PD 8010-2:2015

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Pipeline systems –

Part 2: Subsea pipelines – Code of practice

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Summary of pages

This document comprises a front cover, an inside front cover, pages i to vi, pages 1 to 162, an inside back cover and a back cover.

Foreword

Publishing information

This part of PD 8010 is published by BSI Standards Limited, under licence from The British Standards Institution, and came into effect on 31 March 2015. It was prepared by Subcommittee PSE/17/2, *Pipeline transportation systems*, under the authority of Technical Committee PSE/17, *Materials and equipment for petroleum*. A list of organizations represented on these committees can be obtained on request to their secretary.

Supersession

This part of PD 8010 supersedes PD 8010-2:2004, which is withdrawn.

Relationship with other publications

The PD 8010 series comprises:

- Part 1: *Steel pipelines on land – Code of practice*;
- Part 2: *Subsea pipelines – Code of practice*;
- Part 3: *Steel pipelines on land – Guide to the application of pipeline risk assessment to proposed developments in the vicinity of major accident hazard pipelines containing flammables – Supplement to PD 8010-1:2004*;
- Part 4: *Steel pipelines on land and subsea pipelines – Code of practice for integrity management*;
- Part 5: *Subsea pipelines – Guide to operational practice*.

This part of PD 8010 has been prepared to take into account the publication of BS EN 14161, which is based on ISO 13623. It provides a more comprehensive approach and covers a number of issues that are outside the scope of BS EN 14161.

Information about this document

This is a full revision of the standard, and introduces the following principal changes:

- general updating of the text to take into account new standards and legislation introduced since the 2004 edition;
- update of the guidance for pipelines carrying carbon dioxide;
- update of the guidance on high integrity pressure protection systems (HIPPS), strain based design, fracture and fatigue;
- limiting of applicability to 500 m water depth.

This part of PD 8010 is intended for use by designers, manufacturers, operators and owners of pipelines. Clause **4** deals with health, safety and assurance and is relevant to all users of this document. Clause **5** to Clause **9** are mainly of relevance to designers. Clause **10** and Clause **11** are mainly of relevance to constructors. Clause **12** might be of relevance to both constructors and operators. Clause **13** and Clause **14** are mainly of relevance to operators.

The International System of Units (SI) (see BS EN ISO 80000-1) is followed in this part of PD 8010, except for units of pressure where the bar equivalent is provided for information.

NOTE 1 bar = 10^5 N/m^2 = 10^5 Pa. All references to pressure are gauge pressure, unless otherwise stated.

Hazard warnings

WARNING. This part of PD 8010 calls for the use of substances and/or procedures that can be injurious to health if adequate precautions are not taken. It refers only to technical suitability and does not absolve the user from legal obligations relating to health and safety at any stage.

Use of this document

As a code of practice, this part of PD 8010 takes the form of guidance and recommendations. It should not be quoted as if it were a specification and particular care should be taken to ensure that claims of compliance are not misleading.

Any user claiming compliance with this part of PD 8010 is expected to be able to justify any course of action that deviates from its recommendations.

It has been assumed in the drafting of this Published Document that the execution of its provisions will be entrusted to appropriately qualified and experienced people, for whose use it has been produced.

Presentational conventions

The provisions of this standard are presented in roman (i.e. upright) type. Its recommendations are expressed in sentences in which the principal auxiliary verb is "should".

Commentary, explanation and general informative material is presented in smaller italic type, and does not constitute a normative element.

Where words have alternative spellings, the preferred spelling of the Shorter Oxford English Dictionary is used (e.g. "organization" rather than "organisation").

Contractual and legal considerations

This publication does not purport to include all the necessary provisions of a contract. Users are responsible for its correct application.

Compliance with a Published Document cannot confer immunity from legal obligations.

Particular attention is drawn to the following specific regulations:

- Coast Protection Act 1949 [1];
- Construction (Design and Management) Regulations 2007 [2];
- Continental Shelf Act 1989 [3];
- Environmental Protection Act 1990 [4];
- Food and Environment Protection Act 1985 [5];
- Gas Safety (Management) Regulations 1996 [6];
- Health and Safety at Work, etc. Act 1974 [7];
- Health and Safety at Work, etc. Act 1974 (Application Outside Great Britain) Order 1995 [8];
- Health and Safety at Work (Northern Ireland) Order 1978 [9];
- Offshore Chemicals Regulations 2002 [10];
- Offshore Installation (Safety Case) Regulations 2005 [11];
- Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 [12];

- Offshore (Oil and Gas) Installation and Pipeline Abandonment Fees Regulations 2012 [13];
- Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 [14];
- Oil and Pipelines Act 1985 [15];
- Petroleum Act 1998 [16];
- Pipe-line Works (Environmental Impact Assessment) Regulations 2000 [17];
- Pipelines Safety Regulations 1996 [18];
- Pipelines Safety Regulations (Northern Ireland) 1997 [19];
- Pipelines Safety (Amendment) Regulations 2007 [20];
- Pressure Equipment Regulations 1999 [21];
- Pressure Systems Safety Regulations 2000 [22];
- Prevention of Oil Pollution Act 1986 [23];
- Radioactive Substances Act 1993 [24];
- Submarine Pipelines (Designated Owners) Order 2010 [25].

Attention is also drawn to guidance notes published by appropriate authorities.

1 Scope

This part of PD 8010 gives recommendations for and guidance on the design, selection, specification and use of materials, construction, installation, testing, commissioning, operation, maintenance and abandonment of steel subsea pipelines in offshore, nearshore and landfall environments. Guidance on the use of flexible composite pipelines is also given.

It is not intended to replace or duplicate hydraulic, mechanical or structural design manuals.

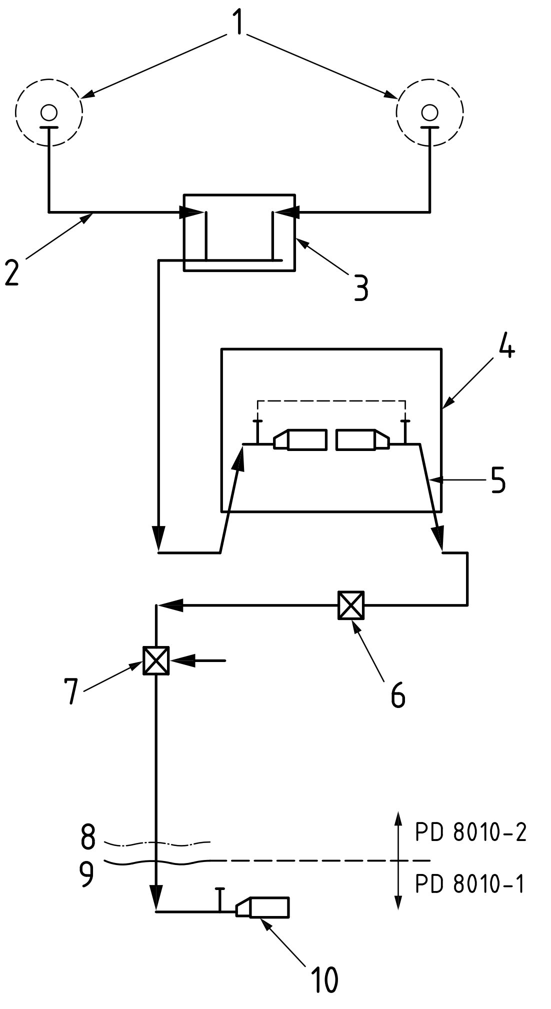
This part of PD 8010 is applicable to subsea pipelines intended for the conveyance of hydrocarbon liquids, hydrocarbon gases, carbon dioxide and other gases, liquids and gases in two-phase flow, fluid-based slurries and water.

NOTE 1 Although primarily concerned with subsea pipelines associated with the oil and gas industry, PD 8010-2 is likely to have application to a wider range of offshore activities.

The extent of pipeline systems covered by this part of PD 8010 is shown in Figure 1. This part of PD 8010 is applicable to pipelines in water depths up to 500 m.

NOTE 2 In deeper water, other international codes such as DNV-RP-F101 are applicable.

Figure 1 **Extent of pipeline systems that are covered by this part of PD 8010**



Key

1 Wellheads
2 Flow line
3 Manifold
4 Offshore installation
5 Riser
6 Valve station
7 Intermediate station
8 Low water
9 High water
10 Receiving facility or AGI
—— Pipeline and facilities covered by PD 8010-2
--- Pipeline and facilities not covered by PD 8010-2
⊠ Intermediate station: valve, tee, wye
Pig trap

This part of PD 8010 does not give recommendations for pipelines on land, which are covered in PD 8010-1. It does not cover sea outfalls (see BS EN 752) or fluid umbilicals (see BS EN ISO 13628-5).

2 Normative references

The following documents, in whole or in part, are normatively referenced in this document and are indispensable for its application. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

Standards publications

ASME B16.5, *Pipe flanges and flanged fittings* [1)]

ASME B16.9, *Factory-made wrought steel buttwelding fittings*

ASME B16.11, *Forged fittings, socket-welding and threaded*

ASME B16.20, *Metallic gaskets for pipe flanges – Ring joint spiral wound and jacketed*

ASME B16.21, *Nonmetallic flat gaskets for pipes flanges*

ASME B16.47, *Large diameter steel flanges*

ASME B31.3, *Chemical plant and petroleum refinery piping – Process piping*

ASME B31.8, *Chemical plant and petroleum refinery piping – Gas transmission and distribution piping systems*

ASME BPVC-VIII-1, *Boiler and pressure vessels code – Section VIII, Division 1: Rules for construction of pressure vessels – Design and fabrication of pressure vessels*

ASME BPVC-IX, *Boiler and pressure vessels code – Section IX: Welding and brazing qualifications*

ASTM A193/A193M, *Specification for alloy-steel and stainless steel bolting materials for high-temperature service* [2)]

ASTM A194/A194M, *Specification for carbon and alloy steel nuts for bolts for high pressure or high-temperature service, or both*

ASTM A262, *Practices for detecting susceptibility to intergranular attack in austenitic stainless steel*

ASTM A264, *Standard specification for stainless chromium-nickel steel-clad plate*

ASTM A265, *Standard specification for nickel and nickel-base alloy-clad steel plate*

ASTM A312, *Standard specification for seamless and welded austenitic stainless steel pipes*

ASTM A320/A320M, *Specification for alloy/steel bolting materials for low-temperature service*

ASTM A790, *Standard specification for seamless and welded ferritic/austenitic stainless steel pipe*

ASTM B423, *Standard specification for nickel-iron-chromium-molybdenum-copper alloy (UNS N08825 AND N08221)* seamless pipe and tube*

1) American Society of Mechanical Engineers (ASME) standards are available from BSI Customer Services, Tel: +44 845 086 9001.

2) ASTM International (formerly American Society for Testing and Materials) standards are available from BSI Customer Services, Tel: +44 845 086 9001.

ASTM B444, *Standard specification for nickel-chromium-molybdenum-columbium alloys (UNS N06625) and nickel-chromium-molybdenum-silicon alloy (UNS N06219) pipe and tube*

ASTM C171, *Specification for sheet materials for curing concrete*

BS 1881 (all parts), *Testing concrete*

BS 3293, *Specification for carbon steel pipe flanges (over 24 inches nominal size) for the petroleum industry*

BS 3518-1, *Methods of fatigue testing – Part 1: Guide to general principles*

BS 3518-3, *Methods of fatigue testing – Part 3: Direct stress fatigue tests*

BS 3799, *Specification for steel pipe fittings, screwed and socket-welding for the petroleum industry*

BS 4482, *Steel wire for the reinforcement of concrete products – Specification*

BS 4483, *Steel fabric for the reinforcement of concrete – Specification*

BS 4515-1, *Specification for welding of steel pipelines on land and offshore – Part 1: Carbon and carbon manganese steel pipelines*

BS 4515-2, *Specification for welding of steel pipelines on land and offshore – Part 2: Duplex stainless steel pipelines*

BS 4882, *Specification for bolting for flanges and pressure containing purposes*

BS 6349-1-4, *Maritime works – Part 1-4: General – Code of practice for materials*

BS 6374-3, *Lining of equipment with polymeric materials for the process industries – Part 3: Specification for lining with stoved thermosetting resins*

BS 6374-4, *Lining of equipment with polymeric materials for the process industries – Part 4: Specification for lining with cold curing thermosetting resins*

BS 7371-12, *Coatings on metal fasteners – Requirements for imperial fasteners*

BS 7448 (all parts), *Fracture mechanics toughness tests*

BS 7608, *Guide to fatigue design and assessment of steel products*

BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*

BS EN 197-1, *Cement – Part 1: Composition, specifications and conformity criteria for common cements*

BS EN 1991-1-4, *Eurocode 1 – Actions on structures – Part 1: General actions – Wind actions*

BS EN 10204, *Metallic products – Types of inspection documents*

BS EN 10224, *Non alloy steel tubes and fittings for the conveyance of water and other aqueous liquids – Technical delivery conditions*

BS EN 10244-2, *Steel wire and wire products – Non-ferrous metallic coatings on steel wire – Part 2: Zinc or zinc alloy coatings*

BS EN 10311, *Joints for the connection of steel tubes and fittings for the conveyance of water and other aqueous liquids*

BS EN 12620, *Aggregates for concrete*

BS EN 13480-3, *Metallic industrial piping – Part 3: Design and calculation*

BS EN ISO 148-1, *Metallic materials – Charpy pendulum impact test – Part 1: Test method*

BS EN ISO 1461, *Hot dip galvanized coatings on fabricated iron and steel articles – Specifications and test methods*

BS EN ISO 3183:2012, *Petroleum and natural gas industries – Steel pipe for pipeline transportation systems* [3)]

BS EN ISO 8501 (all parts), *Preparation of steel substrates before application of paints and related products – Visual assessment of surface cleanliness*

BS EN ISO 8502 (all parts), *Preparation of steel substrates before application of paints and related products – Tests for the assessment of surface cleanliness*

BS EN ISO 8503 (all parts), *Preparation of steel substrates before application of paints and related products – Surface roughness characteristics of blast-cleaned steel substrates*

BS EN ISO 9606-1, *Qualification testing of welders – Fusion welding – Part 1: Steels*

BS EN ISO 12944 (all parts), *Paints and varnishes – Corrosion protection of steel structures by protective paint systems*

BS EN ISO 13628-2, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 2: Bonded flexible pipe systems for subsea and marine applications*

BS EN ISO 13628-15, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 15: Subsea structures and manifolds*

BS EN ISO 14713 (all parts), *Zinc coatings – Guidelines and recommendations for the protection against corrosion of iron and steel in structures*

BS EN ISO 15156 (all parts), *Petroleum and natural gas industries – Materials for use in H2S-containing environments in oil and gas production*

BS EN ISO 15607, *Specification and qualification of welding procedures for metallic materials – General rules*

BS EN ISO 15609 (all parts), *Specification and qualification of welding procedures for metallic materials – Welding procedure specification*

BS EN ISO 15610, *Specification and qualification of welding procedures for metallic materials – Qualification based on tested welding consumables*

BS EN ISO 15614 (all parts), *Specification and qualification of welding procedures for metallic materials – Welding procedure test*

BS EN ISO 15653, *Metallic materials – Method of test for the determination of quasistatic fracture toughness of welds*

BS EN ISO 15589-2, *Petroleum and natural gas industries – Cathodic protection for pipeline transportation systems – Part 2: Offshore pipelines*

BS ISO 1143, *Metallic materials – Rotating bar bending fatigue testing*

BS ISO 7005-1, *Pipe flanges – Part 1: Steel flanges for industrial and general service piping systems*

BS ISO 10474, *Steel and steel products – Inspection documents*

BS ISO 12107, *Metallic materials – Fatigue testing – Statistical planning and analysis of data*

ISO 14313, *Petroleum and natural gas industries – Pipeline transportation systems – Pipeline valves*

ISO 15590-1, *Petroleum and natural gas industries – Induction bends, fittings and flanges for pipeline transportation systems – Part 1: Induction bends*

[3)] API 5L:2012 is the same as BS EN ISO 3183:2012, except that the API standard does not include Annex M.

ISO 15590-2, *Petroleum and natural gas industries – Induction bends, fittings and flanges for pipeline transportation systems – Part 2: Fittings*

ISO 15590-3, *Petroleum and natural gas industries – Induction bends, fittings and flanges for pipeline transportation systems – Part 3: Flanges*

ISO/DIS 13628-14, *Petroleum and natural gas industries – Design and operation of subsea production systems – Part 14: Subsea high integrity pressure protection systems (HIPPS)*

PD 5500, *Specification for unfired fusion welded pressure vessels* [4)]

Industry standards publications

API 5L:2012 (45th edition), *Specification for line pipe*

API 5LC, *Specification for CRA line pipe*

API 5LD, *Specification for CRA clad or lined steel pipe*

API 6A, *Wellhead and Christmas tree equipment*

API 17J, *Specification for unbonded flexible pipe*

API 1104, *Standard for welding of pipelines and related facilities*

API RP 17B, *Recommended practice for flexible pipe*

API RP 170, *Recommended practice for subsea high integrity pressure protection systems (HIPPS)*

AWWA C205, *Cement-mortar protective lining and coating for steel water pipe – 4 in. (100 mm) and larger for water service – Shop application* [5)]

AWWA C602, *Cement-mortar lining of water pipelines in place – 4 in. (100 mm) and larger*

DNV-OS-F101, *Submarine pipeline systems* [6)]

DNV-RP-F103, *Cathodic protection of submarine pipelines by galvanic anodes* [7)]

DNV-RP-F106, *Factory-applied external pipeline coatings for corrosion control*

MSS SP 44, *Specification for steel pipelines flanges* [8)]

NACE MR0175, *Metals for sulfide stress cracking and stress corrosion cracking resistance in sour oilfield environments* [9)]

4) This part of PD 8010 also gives an informative reference to PD 5500:2012+A3:2014.

5) American Water Works Association (AWWA) standards are available from BSI Customer Services, Tel: +44 845 086 9001.

6) This part of PD 8010 also gives informative references to DNV-OS-F101:2013.

7) Det Norske Veritas (DNV) standards are available from BSI Customer Services, Tel: +44 (0)20 8996 9001.

8) Manufacturers Standardization Society (MSS) standards are available from BSI Customer Services, Tel: +44 845 086 9001.

9) National Association of Corrosion Engineers (NACE) standards are available from BSI Customer Services, Tel: +44 845 086 9001.

3 Terms, definitions, symbols and abbreviations

3.1 Terms and definitions

For the purposes of this part of PD 8010, the following terms and definitions apply.

NOTE Additional definitions are given in BS EN 14161 and ISO 13623.

3.1.1 bulkheads

stress distribution diaphragms within an encased bundle or pipe-in-pipe system, or watertight compartment separation diaphragms

3.1.2 bundle

group or configuration of two or more pipelines mechanically joined together for the purpose of combined installation

3.1.3 cathodic protection

system that reduces the rate of external corrosion of steel pipeline, and the ferrous compounds of pipeline components, by regulating the electrical potential between a pipeline and its environment

3.1.4 commissioning

introduction of product into a pipeline to put the system into operation

3.1.5 component

any item that is part of a pipeline other than a straight pipe or field bend

NOTE A component can also be referred to as a fitting.

3.1.6 decommissioning

activities required to take out of service any pipework, station, equipment or assemblies and to isolate them from the pipeline system

NOTE This does not necessarily include abandonment.

3.1.7 design factor

factor applied to hoop stress when calculating the wall thickness or pressure

3.1.8 design life

time period for which a pipeline is to be used for its intended purpose with planned integrity management

3.1.9 design pressure

pressure on which design criteria are based

3.1.10 design temperature

maximum or minimum temperature which determines the selection of material for the duty proposed

NOTE This represents the most arduous condition expected.

3.1.11 emergency

situation which could affect the safe operation of the pipeline system and/or the health, safety and environment of the surrounding area, requiring urgent action

3.1.12 gas

fluid that has a gaseous state at a temperature of 15 °C under normal atmospheric pressure

3.1.13 holiday

flaw in the coating or lining of a pipe

3.1.14 incident
unexpected occurrence that could lead to an emergency situation

3.1.15 installation
equipment and facilities for the extraction, production, chemical treatment, measurement, control, storage or offtake of the transported fluid

3.1.16 intermediate station
pump, compressor, valve, pressure control, heating or metering station, etc. located along a pipeline route between the pipeline terminals

3.1.17 internal design pressure
maximum sustained pressure exerted by the pipeline contents which a pipeline is designed to withhold

3.1.18 incidental pressure
level of pressure that occurs incidentally within a system, at which a safety device becomes operative

3.1.19 installation temperature
temperature arising from ambient or installation conditions during laying or during construction

3.1.20 isolation joint
fitting having high electrical resistance, which can be inserted in a pipeline to electrically insulate one section of pipeline from another

3.1.21 J-tube
J-shaped tube installed on a platform, through which a pipeline can be pulled to form a riser

3.1.22 lay corridor
corridor in which an offshore pipeline is to be installed, usually determined prior to construction

3.1.23 line pipe
standard length of pipe (**3.1.31**) as supplied for the construction of pipelines

3.1.24 lining
durable material applied to the internal surface of steel pipes and fittings to protect the metal from corrosion, erosion or chemical attack

3.1.25 maximum allowable operating pressure (MAOP)
maximum pressure at which a system can be operated continuously under normal conditions at any point along the pipeline and which is the sum of the static head pressure, the pressure required to overcome friction losses and any required backpressure

3.1.26 operating pressure
pressure that occurs within a pipeline system under normal operating conditions

3.1.27 operating temperature
temperature that occurs within a pipeline system under normal operating conditions

3.1.28 operator
person or organization having control over the conveyance of fluid through a pipeline system at any time during all stages of its life cycle

NOTE Further information on the definition of "operator" is given in the Pipelines Safety Regulations 1996 [18], Regulation 2.

3.1.29 pig
device propelled through a pipeline by fluid pressure, for cleaning, swabbing, gauging, inspection or batch separation

3.1.30 pig trap
device allowing entry to a pipeline for the launching and receiving of pigs, inspection tools and other equipment to be run through a pipeline

3.1.31 pipe
hollow cylinder through which fluid can flow, as produced by the manufacturer prior to assembly into a pipeline

3.1.32 pipe string
continuous assembly of pipe joints

3.1.33 pipe-in-pipe
system of two pipes, constructed with one inside the other, usually concentric

NOTE The annulus (space) between the two pipes is usually filled with an insulating material, which is protected from the sea by the outer pipe.

3.1.34 pipeline
continuous line of pipes of any length, without frequent branches, used for transporting fluids

NOTE 1 Pipelines do not include piping systems such as process plant piping within refineries, factories or treatment plants. However, the pipeline system covers the pipeline plus all operational equipment needed to control and operate the pipeline. Refer to Figure 1 for physical clarification of a pipeline system and a pipeline limit.

NOTE 2 A subsea pipeline is a pipeline laid under maritime waters and estuaries and the shore below the high water mark. A pipeline on land is a pipeline laid on or in land, including those sections laid under rivers, lakes and inland watercourses. Recommendations for pipelines on land are given in PD 8010-1.

NOTE 3 Various examples of the interfaces of pipelines with other piping systems are given in Clause ***5*** *and while these are indicative, they give an illustration of the limits where the application of PD 8010 can be applied.*

3.1.35 pipeline system
full pressure envelope from the pressure source to the receiving vessel or pressure letdown station

NOTE Attention is also drawn to the definition given in the Pipelines Safety Regulations 1996 [18]. The extent of pipeline systems covered in this part of PD 8010 is illustrated in Figure 1.

3.1.36 pipework
assembly of pipes and fittings

3.1.37 pre-commissioning
activities, including cleaning, pigging, testing, de-watering, purging and drying as appropriate, carried out prior to commissioning

3.1.38 pressure
gauge pressure of the fluid inside a system, measured in static conditions

3.1.39 re-commissioning
activities required to put a decommissioned pipeline, associated stations and equipment back into service

3.1.40 redundancy
incorporation of components in parallel in a control system, in which the system fails to operate only if all its components fail to operate

3.1.41 reliability
probability of a device or system performing in the manner desired for a specified period of time

3.1.42 riser
section that extends between a pipeline on the sea floor and the pipeline termination point on a platform or similar facility

3.1.43 spacer
non-stress distribution element provided to locate and support pipelines within the configuration of strapped or encased bundles

3.1.44 splash zone
zone in which a structure can be subject to the effects of both wind and sea

3.1.45 station
plant or facility for the operation of a pipeline system and/or the processing of fluid

3.1.46 strength test
specific procedure used to ascertain whether the pipeline, pipework and/or station meets the recommendations for mechanical strength

3.1.47 surge pressure
maximum pressure caused by:

a) rapid closure of valves during pipeline operation;

b) pump trips and re-start operations;

c) vacuum cavities in the pipeline;

d) reverse flow operations;

e) a combination of the above usually caused by mal-operation

NOTE Surge pressure is applied to liquid lines and multi-phased lines. Uninhibited surge pressure is the maximum of the combination of liquid surge pressure at maximum operation conditions and the pump shut-in head pressure.

3.1.48 subsea pipeline
pipeline laid under maritime waters and estuaries, or under the shore below high water mark

3.1.49 tapping
mechanical cutting into a pipeline to enable a connection to be made

3.1.50 test pressure
pressure to which a system is subjected to ascertain whether it can operate safely

3.1.51 tie-in weld
weld carried out between two sections of pipeline to join the sections together before or after a pressure test

NOTE A tie-in weld after pressure test is also known as a non-pressure-tested closure weld (golden weld).

3.1.52 transient pressure

pressure fluctuation created by an upset in the steady state flow conditions in a pipeline

NOTE Transient pressure is normally caused by valve operation, pump start or trip-out, or by the fluctuation of a control valve and inaccuracies of instrument set points.

3.1.53 trim/weight chain

chain attached to bundle for the purpose of buoyancy adjustment to suit installation by towing

3.2 Symbols

For the purposes of this part of PD 8010, the following symbols apply.

A cross-sectional area of pipe wall, in square metres (m^2)

C_D drag coefficient

C_L lift coefficient

C_M inertia coefficient

C_f flattening coefficient

C_p ovalization magnification factor accounting for pressure effects

C_s slamming coefficient

D total pipe outside diameter including coating and marine growth, in metres (m)

D_i inside diameter of a pipe given by $D_o - 2t$, in metres (m)

D_{max} maximum (oval) outside diameter, in metres (m)

D_{min} minimum (oval) outside diameter, in metres (m)

D_o outside diameter of a pipe, in metres (m)

E Young's modulus of elasticity, in newtons per square metre (N/m^2)

F_D hydrodynamic drag force per unit length, in newtons per metre (N/m)

F_I hydrodynamic inertia force per unit length, in newtons per metre (N/m)

F_L hydrodynamic lift force per unit length, in newtons per metre (N/m)

F_W wave slam force, in newtons per metre (N/m)

F_s shear force applied to a pipeline, in newtons (N)

F_x axial force (compressive), in newtons (N)

F_{xc} mean axial compressive load, in newtons (N)

F_y yield load, in newtons (N)

f total ovalization of a pipe

f_d design factor (see Table 2)

f_o initial ovalization of a pipe cross-section

NOTE 1 The term "initial" refers to the deflection due to influences, including fabrication and bending loads, other than hydrostatic pressure.

g gravitational constant, in metres per second squared (m/s^2)

H_B height of breaking wave, in metres (m)

H_c characteristic upheaval buckle imperfection height, in metres (m)

H_{m0} spectral significant wave height, in metres (m)

H_{max} maximum wave height, in metres (m)

H_s significant wave height, in metres (m)

I second moment of area, in metres to the power 4 (m^4)

L_c characteristic length associated with upheaval buckle imperfection, in metres (m)

L_0 deep water wavelength, in metres (m)

M bending moment, in newton metres (N·m)

M_c characteristic bending moment, in newton metres (N·m)

M_p full plastic moment capacity of pipeline cross-section, in newton metres (N·m)

m_0 zeroth spectral moment

NOTE 2 This is equal to the variance on the sea surface elevation.

m_2 second spectral moment

n inner bend radius divided by pipe diameter for wall thinning formulae

P external overpressure (buckling), in newtons per square metre (N/m^2)

P_c characteristic external pressure (collapse), in newtons per square metre (N/m^2)

P_{cm} carbon equivalent for lean chemistry carbon alloy steels

P_e critical pressure for an elastic circular tube, in newtons per square metre (N/m^2)

P_{eff} effective axial force, in newtons (N)

P_i internal pressure, in newtons per square metre (N/m^2)

P_o external pressure, in newtons per square metre (N/m^2)

P_p buckle propagation pressure, in newtons per square metre (N/m^2)

P_y yield pressure, in newtons per square metre (N/m^2)

R riser diameter, in metres (m)

S_F stability safety factor

T torque applied to a pipeline, in newton metres (N·m)

T_S significant wave period, in seconds (s)

T_m mean wave period, in seconds (s)

T_p period at which peak occurs in the wave spectrum, in seconds (s)

T_z zero-crossing wave period, in seconds (s)

t_{corr} corrosion allowance, in metres (m)

t_{fab} fabrication tolerance allowing for permitted wall thickness variations, in metres (m)

t_{min} minimum wall thickness, in metres (m)

NOTE 3 This excludes corrosion allowance and mill tolerance.

t_{nom} nominal wall thickness, in metres (m)

t_{thin} wall thinning, as a percentage (%)

u water particle velocity normal to the pipe axis, in metres per second (m/s)

NOTE 4 This incorporates components due to both wave action and steady current.

u_s	velocity of water surface normal to the pipe surface (water surface vertical velocity), in metres per second (m/s)
V_i	increased velocity, in metres per second (m/s)
V_u	uniform flow velocity, in metres per second (m/s)
W_s	submerged weight of pipeline per unit length, in newtons per metre (N/m)
Z	pipe section modulus, in cubic metres (m^3)
z	distance between the centre line of an obstruction to the point of measurement, in metres (m)
α	wave-induced water particle acceleration normal to the pipe axis, in metres per second squared (m/s^2)
α_{fab}	fabrication factor
α_τ	torsion coefficient
γ	factor used in the calculation of load combinations
ε_b	maximum bending strain
ε_{bc}	characteristic bending strain
ε_p	equivalent plastic strain
ε_{pL}	principal longitudinal plastic strain
ε_{ph}	principal circumferential (hoop) strain
ε_{pr}	radial plastic strain
Φ_L	imperfection coefficient
Φ_W	download coefficient
μ	lateral soil friction coefficient
ν	Poisson’s ratio
ρ	mass density of seawater, in kilograms per cubic metre (kg/m^3)
σ_A	allowable stress (hoop or equivalent), in newtons per square metre (N/m^2)
σ_L	longitudinal stress (combination of direct and bending stresses), in newtons per square metre (N/m^2)
σ_e	equivalent stress (von Mises), in newtons per square metre (N/m^2)
σ_h	hoop stress, in newtons per square metre (N/m^2)
σ_{hb}	hoop stress used in buckling analysis, in newtons per square metre (N/m^2)
σ_{hcr}	critical compressive hoop stress when pressure is acting alone, in newtons per square metre (N/m^2)
σ_{hE}	critical compressive hoop stress for completely elastic buckling, in newtons per square metre (N/m^2)
σ_y	SMYS of pipe wall material, in newtons per square metre (N/m^2)
τ	shear stress, in newtons per square metre (N/m^2)
τ_C	characteristic torsional shear stress, in newtons per square metre (N/m^2)
τ_y	yield shear stress, in newtons per square metre (N/m^2)
ω	submerged weight of pipe plus over-burden, in newtons per metre (N/m)

3.3 Abbreviations

For the purposes of this part of PD 8010, the following abbreviations apply.

AGI	above-ground installation
ALARP	as low as reasonably practicable
AUT	automated ultrasonic testing
CE	carbon equivalent
CRA	corrosion-resistant alloy
DEH	direct electric heating
DP	dye penetrant
DWT	deadweight tester
DWTT	drop weight tear testing
ECA	engineering critical assessment
ESDV	emergency shutdown valve
HAZ	heat-affected zone
HIC	hydrogen-induced cracking
HIPPS	high integrity pressure protection systems
LPG	liquefied petroleum gas
MAHP	major accident hazard pipeline
MAOP	maximum allowable operating pressure
MPI	magnetic particle inspection
NDT	non-destructive testing
NGL	natural gas liquid
ROV	remotely operated vehicle
SCC	stress corrosion cracking
SMYS	specified minimum yield strength
SSC	sulfide stress cracking
SSIV	subsea isolation valve
UT	ultrasonic testing

4 Health, safety and assurance

4.1 Health, safety and the environment

The recommendations included in this part of PD 8010 are based upon considerations of safety extending throughout the lifetime of a pipeline system.

Experienced and competent engineering judgement should be employed to assess the individual requirements of each pipeline project undertaken.

The design, chosen materials, route, environmental impact and hazard/risk analysis should all be fully assessed and the most appropriate measures selected to ensure as far as possible that the pipeline system will be fit for service throughout its lifetime.

4.2 Competence assurance

The design, construction, testing, operation, maintenance and abandonment of the pipeline system should be carried out by suitably qualified and competent persons, under the supervision of an experienced chartered engineer or equivalent.

NOTE The best manufacturing and construction methods cannot compensate for inadequate design.

Procedures should be established and maintained to control and verify the design, construction and testing of the pipeline, to ensure that the pipeline specification is met, and to minimize error during this process.

4.3 Quality assurance

4.3.1 General

Quality assurance procedures should be applied throughout the feasibility, investigation, design, procurement, construction, testing, operation, maintenance and modification of a pipeline system to ensure compliance with all the relevant standards.

An efficient document control system is essential. A quality plan should be developed appropriate to the duty and nature of the substance to be carried. For pipelines conveying category A, category B or category C substances, some of the quality recommendations given in Annex A may be omitted as appropriate for the nature of the hazard and the pressure of the system, provided that it can be demonstrated that the integrity of the pipeline and quality system can be maintained. For pipelines conveying category D or category E substances, all of the recommendations given in Annex A should be followed.

***Assessed capability**. Users of this Published Document are advised to consider the desirability of quality system assessment and registration against the appropriate standard in the BS EN ISO 9000 and BS EN ISO 14001 series by an accredited third-party certification body.*

4.3.2 Inspection

The level of inspection should be such as to meet the requirements of the quality plan (see Annex A and **B.6**). Inspection activities should be certified by appropriately qualified personnel.

4.3.3 Records and document control

All documents, specifications, drawings, certificates and change orders relating in any way to project quality should be retained, cross-referenced and filed in accordance with the quality plan.

Annex B gives details of the documents that should normally be included in the quality system.

For pipelines conveying category A, category B or category C substances, some of these documents may be omitted due to the low risk nature of the hazard and the low pressure of the system, provided that it can be demonstrated that the integrity of the pipeline and its essential documentation can be maintained.

NOTE The control of pipeline records and operations can be improved by the use of electronic systems, such as pipeline databases and geographical information system (GIS).

All design, procurement, construction, testing, inspection and survey documentation should be retained for the life of the pipeline.

4.4 Design, construction and commissioning assurance

A design assurance system should be established, such as the one shown in Figure 2, which should include all aspects of the design process. As a minimum it should include all of the issues addressed in Clause **5** to Clause **9**. It should also address practicalities and limitations associated with construction (Clause **10** and Clause **11**), and requirements for pre-commissioning and commissioning (Clause **12**), operation (Clause **13**), and abandonment (Clause **14**).

The construction through to commissioning process should reflect the design and should take into account, validate and record any changes or deviations from the original design (see also **4.6.3**).

NOTE The pipeline design flowchart shown in Figure 2 has been developed to give general guidance on the design process. This flowchart may be used as a guide through the design process. It does not attempt to show all the various pathways required to arrive at the chosen design.

4.5 Operation and abandonment assurance

The operation and abandonment process should take into account the design, any changes made during or subsequent to construction, and the condition of the system (see Clause **13** and Clause **14** for more detailed recommendations).

4.6 Plans and drawings

4.6.1 Routeing plans

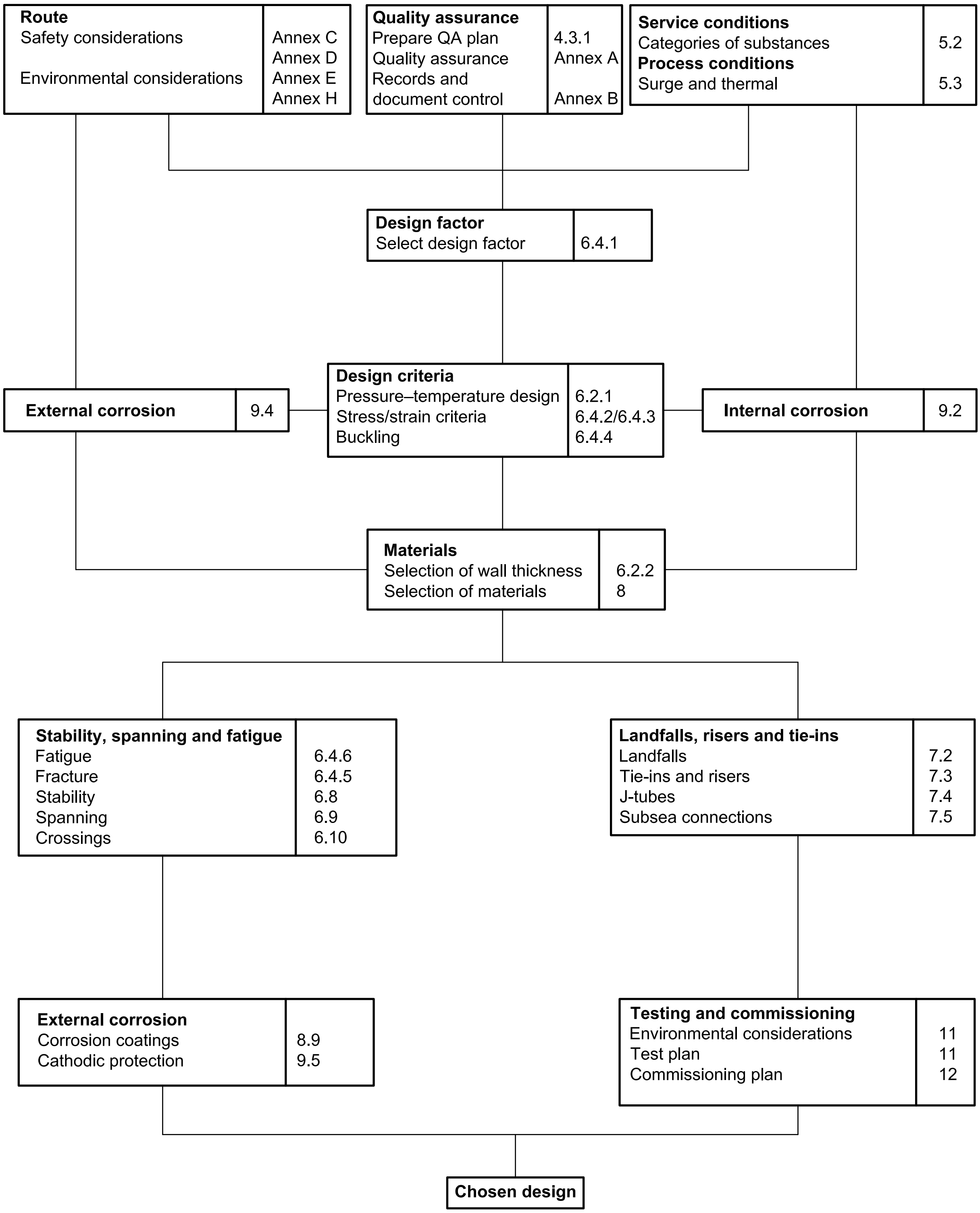
Routeing plans should be developed at an appropriate scale showing the overall pipeline route, proximity of adjacent infrastructure, e.g. other pipelines, cables, offshore production facilities, exploration block ownership, seabed bathymetry and geotechnical features. Features such as pipeline tie-ins and crossings should be indicated.

Marine charts should be updated to show the pipeline route.

4.6.2 Alignment drawings

Detailed alignment drawings should be prepared from survey data to an appropriate scale. Any vertical section or profile along the pipeline route should be shown to a scale appropriate to the variations in seabed elevation. Crossings should be detailed on separate drawings that should be cross-referenced to the appropriate alignment drawing. Details of pipeline parameters along the route such as pipeline wall thickness, coating and anode details, trenching and burial details and installation tolerances should be shown.

Figure 2 **Example of a pipeline design flowchart**



NOTE The numbers shown in the flowchart boxes refer to the subclause numbering of this part of PD 8010.

4.6.3 As-built plans

If during construction of the pipeline there are any changes or deviations from any issued plans following discussions with third parties or changes in design, as-built plans (to the same scale as the original plans) should be issued to all the original recipients on completion of the work.

5 Design – System and safety

*COMMENTARY ON CLAUSE **5***

This clause addresses the safety of the entire pipeline system, including pipeline process engineering.

The extent of a pipeline system covered by this part of PD 8010 is shown in Figure 1.

An example of a design flowchart is given in Figure 2.

5.1 System definition

The extent of the pipeline system, its functional requirements and applicable legislation, including proposals for future abandonment, should be defined and documented.

The extent of the system should be defined by describing the system, including the facilities with their general locations and the demarcations and interfaces with other facilities.

The definition of functional requirements should include the intended design life and design conditions. The design conditions should include foreseeable normal operating conditions, upset and operational extremes, including shut-in operating conditions. It should also include possible ranges in flow rates, pressures, temperatures, fluid compositions and fluid qualities.

Battery limits should be classified as follows.

a) At the landfall, the pipeline may extend onshore to a terminal.

   *NOTE Recommendations for the on-shore section of such pipelines are given in PD 8010-1. The demarcation is described in **7.2.1**.*

b) At a platform, the pipeline extends from the seabed to include the riser and other associated pipework up to and including the pig trap. Any branch connections (e.g. "kicker" lines) are included up to the first valve on such branches. If there is no pig trap, the termination point is up to and including the first valve above sea water level or the emergency shutdown valve (ESDV) if fitted for either internal or external risers. If the pig trap or any associated pipework is located within a process area, standards appropriate to the process area can also apply.

c) At subsea wells, the pipeline normally terminates at the well christmas tree pull-in connection or wing valve. The christmas tree does not form part of the pipeline.

d) At an underwater installation where none of the above limits are applicable, the pipeline terminates at the pull-in connection. The tie-in spool piece is deemed to be part of the pipeline.

e) At an offshore loading system, the pipeline includes the first valve on a permanently moored tanker, or the connecting device that is associated with the loading system, when a transient tanker is used.

Instrument tappings on the pipeline are deemed to be part of the pipeline, but the instrumentation is not.

5.2 Categorization of substances

5.2.1 General

The substances to be transported should be categorized, with respect to hazard potential in respect of public safety, into one of the five categories given in Table 1.

NOTE 1 Attention is drawn to the Pipelines Safety Regulations 1996 [18] for the definition and classification of dangerous fluids (hazardous substances).

Table 1 **Categorization of substances according to hazard potential**

Category	Description	Typical examples
A	Typically non-flammable water-based fluids	Water, brine, dilute effluents
B	Flammable and/or toxic fluids that are liquids at ambient temperature and at atmospheric pressure conditions	Oil and petroleum products Methanol
C	Non-flammable fluids that are non-toxic gases at ambient temperature and atmospheric pressure conditions	Nitrogen, oxygen, argon and air
D	Non-toxic, single-phase natural gas	—
E	Flammable and/or toxic fluids that are gases at ambient temperature and atmospheric pressure conditions and are conveyed as gases and/or liquids Mixtures of petroleum or chemical substances, having a Reid vapour pressure greater than 31 kPa absolute	Hydrogen, carbon dioxide, natural gas (not otherwise covered in category D), ethane, ethylene, liquefied petroleum gas (e.g. propane and butane), natural gas liquids, ammonia and chlorine Spiked or live crude oil

Gases or liquids not specifically included by name should be classified in the category containing substances most closely similar in hazard potential to those quoted. If the category is not clear, the more hazardous category should be assumed.

NOTE 2 Guidance is given in a number of publications including HSE publication L82 [26], and ICE publication Nomenclature for hazard and risk assessment *[27].*

NOTE 3 Additional guidance on CO_2 pipelines is given in DNV-RP-J202.

5.2.2 Hazard potential

COMMENTARY ON ***5.2.2***

In the event of a rupture of a pipeline conveying a gas, the blast effect owing to stored energy is an important factor in the hazard potential of the substance. The rupture of a pipeline conveying a liquid has a much lower blast effect owing to the relatively incompressible nature of liquids. Gases conveyed as liquids have an intermediate effect. The characteristics of some hazardous substances commonly conveyed in pipelines are described in Annex C, to assist the designer in determining the category into which hazardous substances are to be placed.

See also Annex D, which gives recommendations for safety evaluation.

The designer should determine the category into which hazardous substances are to be placed.

5.3 Pipeline process design

5.3.1 General

All pipelines should have a pipelines process data sheet or document including:

a) means of pressure;

b) fluid characteristics;

c) process;

d) pipeline size;

e) fluid volume;

f) fluid transfer rates;

g) modes of pipeline operation;

h) process operating conditions;

i) hydraulic route analysis;

j) maximum operating and surge pressure;

k) direction of flow;

l) maximum shut-in head;

m) surge pressure and surge control;

n) proposed relief systems;

o) thermal relief control.

5.3.2 Hydraulic analysis

The hydraulics of the pipeline system should be analysed to demonstrate that the system can operate safely at the design conditions identified in **5.3.1**, and to identify and determine the constraints and requirements for its operation. The analysis should cover steady state and transient operating conditions.

NOTE Examples of constraints and operational requirements are:

- *allowances for pressure surges;*
- *prevention of blockages, e.g. caused by the formation of hydrates and wax deposition;*
- *measures to prevent unacceptable pressure losses from higher viscosities at lower operating temperatures;*
- *measures for the control of liquid slug volumes in multi-phase fluid transport;*
- *flow regime for internal corrosion control;*
- *erosional velocities and avoidance of slack line operations.*

5.3.3 Pressure control and overpressure protection

The internal design pressure should be selected to take account of the maximum steady shut-in pressure and also, where pipelines are connected to wells, the well kill pressure. During the design process the target MAOP is generally identical to the internal design pressure, and protection systems should be designed to prevent the transient pressures from exceeding 110% of the MAOP. Provisions such as pressure control valves or automatic shutdown of pressurizing equipment should be installed, or procedures implemented, if transient pressures could exceed 110% of the MAOP.

NOTE The MAOP excludes surge pressure and other variations and may be less than the design pressure.

5.3.4 High integrity pressure protection systems

High integrity pressure protection systems should meet the requirements of API RP 170 or ISO DIS 13628-14.

HIPPs protected pipelines may be designed to be burst resistant or burst critical. Fortified zones should be used where necessary on sections of the pipeline close to the manned facilities.

NOTE The HSE website provides guidance on design criteria in document SPC/TECH/OSD/31 [28] [10]*.*

5.3.5 Heated pipeline systems

Seven main types of active heating systems may be used to heat the contents of a subsea pipeline in order to prevent wax or hydrate formation, namely:

a) open loop direct electric heating (DEH);

b) closed loop DEH;

c) pipe-in-pipe DEH (centre or end fed);

d) trace heating;

e) induction heating;

f) skin effect (SECT) heating;

g) hot water circulation.

Account should be taken of the safety, technical reliability, electrical efficiency, repair difficulty and system track record of the proposed system. The impact on the surrounding seawater, coatings and cathodic protection systems should be assessed.

5.3.6 Operation and maintenance

The requirements for operation and maintenance of the pipeline system should be established and documented. For operation and maintenance plans, the specific recommendations given in Clause **13** should be followed.

5.4 Public safety and protection of the environment

*COMMENTARY ON **5.4***

The recommendations given in this subclause are expected to be adequate for public safety and environmental protection under conditions usually encountered in pipelines, including those in offshore and nearshore areas. However, these recommendations do not replace the need for appropriate experience and competent engineering judgement.

Materials and practices not specifically recommended in this part of PD 8010 may be used providing they can be shown to achieve comparable safety standards.

5.4.1 General

The provision of suitable and safe access for in-service inspection should be included at the design stage.

*NOTE The safety and reliability of a pipeline system can be improved by the application of quality assurance procedures in design (see Clause **4**).*

[10] Available at http://www.hse.gov.uk/foi/internalops/hid_circs/technical_osd/spc_tech_osd_31.htm [last accessed 19 March 2015].

5.4.2 Safety evaluation

A safety evaluation should be carried out in accordance with Annex D.

The design of a pipeline should take into account the extra protection that might be necessary to prevent damage arising from any of the hazards identified during the safety evaluation. The effect of the extra protection should be assessed during the safety evaluation to determine whether risks have been reduced to be as low as reasonably practicable (ALARP).

*NOTE Typical examples of extra protection are given in **D.9**.*

5.5 Route selection

Safety, environmental, technical and economic considerations should be the primary factors governing the choice of pipeline routes. The shortest route might not be the most suitable, and physical obstacles, environmental and other factors should be taken into account.

Route selection should further take into account the design, construction, operation, maintenance and abandonment of the pipeline.

For pipeline route selection, the specific recommendations given in Annex E should be followed.

6 Design – Mechanical integrity

*COMMENTARY ON CLAUSE **6***

*This clause deals with the mechanical integrity of a pipeline. Recommendations for pipeline system and safety design are given in Clause **5**.*

6.1 General

The methods used in designing pipelines should be selected in accordance with good engineering practice. Methods of analysis may be based on analytical, numerical or empirical models, or a combination of these methods.

6.2 Design criteria

*COMMENTARY ON **6.2***

The design criteria or design basis of a pipeline are determined by how hazardous the fluid to be conveyed is and how difficult the route is. The more hazardous the fluid, the higher the design quality and the more detailed the design.

6.2.1 Process conditions (pressure–temperature ratings)

6.2.1.1 Pipe and components having specific pressure–temperature ratings

The pressure–temperature ratings for pipe and components should be consistent with the appropriate component standard(s) selected for the project.

6.2.1.2 Components not having specific pressure–temperature ratings

If components not having specific pressure–temperature ratings are to be used, the pressure design should be based on sound engineering analysis supported by proof tests, experimental stress analysis and/or engineering calculations as appropriate.

6.2.1.3 Normal operating conditions

For normal operation the MAOP should not exceed the internal design pressure and pressure ratings for the components used. It should exclude surge pressure, thermal relief pressure and other variations that can occasionally occur above the design pressure.

NOTE The MAOP may be reviewed and revised during the lifetime of the pipeline according to the pressure source, overall pipeline system integrity and condition of the pressure envelope.

6.2.1.4 Allowance for variations from normal operation

NOTE Surge pressures that occur in liquid pipelines can be produced by sudden changes in flow, for example, following valve closure, pump shutdown, pump start-up or blockage of the moving stream.

Surge pressure calculations should be carried out to assess the maximum positive and negative surge pressures in the system. Account should be taken of surge pressures produced within the pipeline affecting systems that are outside the scope of this part of PD 8010, such as upstream of pumping stations or downstream of pipeline terminals.

6.2.1.5 Overpressure protection

Controls and protective equipment should be provided to ensure that the incidental pressure which is the sum of the operational pressure, the surge pressure, thermal relief pressure or other variations from normal operations does not exceed the internal design pressure at any point in the pipeline system by more than 10%.

NOTE The safe operating limit defined in the Pipelines Safety Regulations 1996 [18] is equal to or greater than the incidental pressure.

6.2.1.6 Different pressure conditions

When two pipeline systems operating at different pressure conditions are connected, the valves or components separating the two pipeline systems should be designed for the more severe design conditions.

6.2.2 Pressure design of pipeline and pipeline components

6.2.2.1 Straight pipe under internal pressure

The nominal thickness of steel pipe, minus the specified manufacturing tolerance on wall thickness and the designated corrosion allowance where applicable, should be not less than the design thickness used in the calculation of hoop stress (see **6.4.2.2**). A nominal pipe wall thickness should be selected to ensure structural integrity in construction handling and welding.

6.2.2.2 Straight pipe under external loading

Pipe wall thickness should be sufficient to prevent collapse under conditions during construction or operation when the external pressure exceeds the internal pressure, taking into account pipe mechanical properties, bending stresses, dimensional tolerance and external loads (see BS EN 13480-3 or ASME B31.3).

For pipelines assuming a natural curvature that incurs a permanent elastic bending stress, the minimum bending radius should be determined at the design stage through stress analysis.

6.2.2.3 Bends

All bends should be free from buckling, cracks or other evidence of mechanical damage. The nominal internal diameter of a bend should not be reduced in ovality by more than 2.5% at any point around the bend. Sufficient tangent lengths should be left at each end of a bend to ensure good alignment and to facilitate welding. Pipes bent cold should not contain a girth weld within the bent section.

The wall thickness of finished bends, should take into account wall thinning at the outer radius and the torus effect, and therefore should be greater than the design thickness shown in **6.2.2.1**. An indication of wall thinning as a percentage can be calculated using equation (1).

$$t_{\text{thin}} = \frac{50}{n+1} \tag{1}$$

This formula does not take into account other factors that depend on the bending process, and the bend manufacturer should be consulted where wall thinning is critical.

*NOTE 1 See **8.3.5** for materials aspects of bending.*

Mitred, wrinkled or gusseted bends should not be used in pipelines, with the exception of pipelines conveying category A substances at low pressure (see Note 2). Account should be taken of the use of cleaning, scraper and internal inspection devices (pigs) when specifying the radius of bends intended for installation in pipelines.

NOTE 2 For existing pipelines with mitred, wrinkled or gusseted bends, a fitness-for-purpose assessment is needed for revalidation to ensure structural integrity.

Factory-made bends and factory-made wrought steel elbows may be used provided that they are in accordance with **8.3.5** and the present subclause.

NOTE 3 Additional forces might need to be taken into account.

6.3 Loads

6.3.1 General

The design should account for loads that can cause or contribute to pipeline failure or loss of serviceability. The design should be for the most severe coincident conditions of pressure, temperature and loading which could occur during normal operation or testing.

The loads described in Annex F should be taken into account, and the recommendations in Annex F should be followed for each type of load.

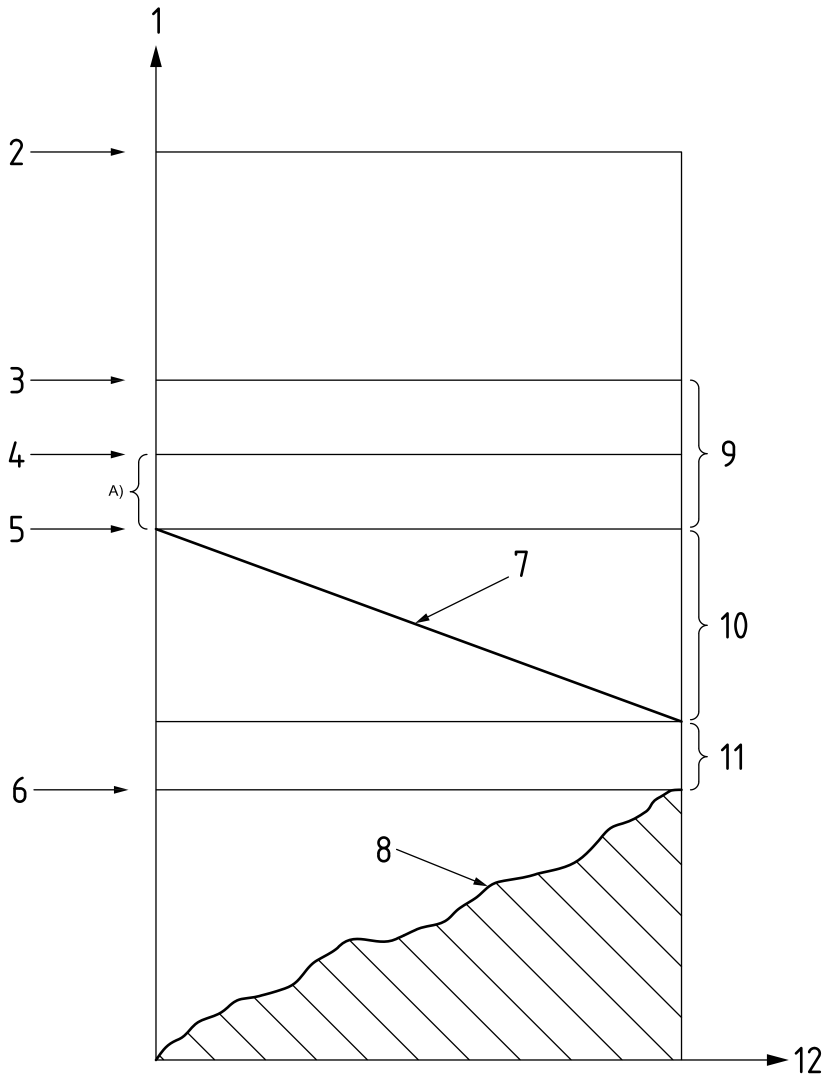
6.3.2 Internal design pressure

The internal design pressure used in design calculations should be not less than the MAOP at that point.

NOTE 1 The MAOP is the sum of the operating pressure, static head pressure, the pressure required to overcome friction losses and any necessary backpressure.
The net internal design pressure used in design calculations may be modified by taking into account the difference in pressure between the inside and outside of any pipeline component.

NOTE 2 The pressure definitions are illustrated in Figure 3.

Figure 3 **Design and test pressure**



Key

1 Pressure
2 Test pressure
3 1.10 × internal design pressure
4 Net internal design pressure A)
5 Maximum allowable operating pressure A)
6 Static head pressure
7 Hydraulic gradient
8 Ground profile
9 Surge pressure, thermal and other variations
10 Pressure recommended to overcome friction losses
11 Recommended backpressure
12 Distance along the pipe

A) The MAOP may vary between these limits dependent upon the test pressure.

6.4 Strength

6.4.1 Design factors

The design factors, f_d, in Table 2 should be used for the stress-based design method in **6.4.2**. The design factors for strain-based design method are given in **6.4.3**.

NOTE BS EN 14161 allows a design factor of up to 0.83 to be used. The design factors recommended for UK use are shown in Table 2. Higher design factors may be used for all or part of a pipeline system, provided that an equivalent level of safety is achieved throughout the system under consideration, and across all relevant limit states. A full risk assessment (see Annex D) is recommended if higher design factors are used, and might be subject to regulatory review.

Table 2 **Design factor, f_d**

Hoop stress		Equivalent stresses resulting from functional and environmental or accidental loads		Equivalent stresses arising from construction or hydrotest loads	
Riser/ landfall	**Seabed including tie-in**	**Riser/ landfall**	**Seabed including tie-in**	**Riser/ landfall**	**Seabed including tie-in**
0.6	0.72	0.72	0.96	1.0	1.0

Where the application of a reliability-based limit state design method leads to a reduction in the wall thickness that is necessary to meet the recommendations for pressure containment, particular attention should be paid to installation and operability considerations, i.e. it should be demonstrated that the selected wall thickness is appropriate for all the load conditions and combinations that can reasonably be expected throughout the life of the pipeline.

Account should be taken of the variation of strength with temperature on the basis of verifiable test data appropriate to the material under consideration.

6.4.2 Stress-based design

6.4.2.1 Allowable stress

Stress in the pipeline system should meet the inequality shown in equation (2).

$$\sigma_A < f_d \sigma_y \qquad (2)$$

where σ_A is determined in accordance with **6.4.2.2** or **6.4.2.4** as appropriate.

The effect of temperature re-rating on the SMYS should be included.

NOTE In the absence of more directly applicable data, the derating data in DNV-OS-F101 may be used.

6.4.2.2 Hoop stress

Hoop stress should be calculated using equation (3) (thin wall) when the ratio of D_o/t_{min} is greater than 20.

$$\sigma_h = \left(P_i - P_o\right)\frac{D_o}{2t_{min}} \qquad (3)$$

The wall thickness used for hoop stress calculation should be the minimum value allowing for permitted wall thickness variations, such as fabrication tolerances, and subtracting any corrosion allowance, i.e. as shown in equation (4).

$$t_{nom} = t_{min} + t_{fab} + t_{corr} \qquad (4)$$

NOTE For clad or lined pipelines, the strength contribution of the cladding or lining is usually not taken into account, unless it is necessary to contribute to the structural integrity.

Equation (5) (thick wall) should be used when the ratio of D_o/t_{min} is less than or equal to 20.

$$\sigma_h = (P_i - P_o)\frac{(D_o^2 + D_i^2)}{(D_o^2 - D_i^2)} \qquad (5)$$

For all other stress checks in this section, t_{nom} should be used in the calculation of component stresses.

6.4.2.3 Expansion and flexibility

Pipelines and piping should be designed with sufficient flexibility to prevent expansion or contraction causing excessive forces or stresses in pipe material, joints, equipment, anchors or supports.

Expansion calculations should be carried out on pipelines where flexibility is in doubt, and where temperature changes are expected. Thermal and pressure expansion or contraction can cause movement at termination points, changes in direction or changes in size. The necessary flexibility should be provided if such movements are unrestrained. Account should be taken of buckling forces that can be imposed on pipelines (see **6.4.4**).

The effect of restraints, such as support friction, branch connections and lateral interferences, should be taken into account.

Calculations should take into account stress intensification factors found to be present in components such as bends and field joints (other than plain straight pipe). Account should be taken of any extra flexibility of such components and field joints.

NOTE In the absence of more directly applicable data, the flexibility factors and stress intensification factors given in BS EN 13480-3 or ASME B31.3 may be used.

Pipelines can be restrained so that the longitudinal movement owing to thermal and pressure changes is absorbed by direct axial compression or tension of the pipe. In such cases expansion calculations should be carried out taking into account all the forces acting on the pipeline. Account should be taken of elastic instability due to longitudinal compressive forces.

Where movement is restrained, flexibility should be provided by means of loops, offsets or special fittings. The total operating temperature range should be taken as the difference between the maximum and minimum metal temperatures for the operating cycle under consideration and should be used in calculating stresses in loops, bends and offsets.

The temperature range used in the calculation of reactions on anchors and equipment should be taken as the difference between the maximum or minimum metal temperatures and the installation temperature, whichever gives the greater reaction.

Where there is a likelihood of repeated stress changes (including thermal stress) giving rise to fatigue conditions, the stress range and allowable number of cycles should be calculated in accordance with **6.4.6**.

Nominal pipe wall thickness (including any corrosion allowance) and nominal outside diameter should be used for expansion and flexibility calculations.

6.4.2.4 Equivalent stress

Unless a strain-based design approach is adopted (see **6.4.3**), equivalent stresses should be evaluated using the von Mises stress criterion shown in equation (6).

$$\sigma_e = \left(\sigma_h{}^2 + \sigma_L{}^2 - \sigma_h\sigma_L + 3\tau^2\right)^{0.5} \tag{6}$$

NOTE 1 Nominal wall thickness may be used in the evaluation.

The total component longitudinal stress should be the sum of the longitudinal stresses arising from pressure, bending, temperature, weight (force), other sustained loadings and occasional loadings. Accidental loads should be taken into account as indicated in **F.7**. Account should be taken of the variation in axial restraint throughout the pipeline.

NOTE 2 A pipeline is deemed to be totally restrained when axial movement and bending resulting from temperature or pressure change is totally prevented.

The shear stress, τ, should be calculated from the torque and shear force applied to the pipeline using equation (7).

$$\tau = \frac{T}{2Z} + \frac{2F_S}{A} \tag{7}$$

6.4.2.5 Pipeline fittings and equipment

The pipeline design should take account of the flexibility of bends and other fittings in the pipeline. Stress intensification in bends and other fittings should be taken into account (see BS EN 13480-3).

Flexibility calculations should be based on nominal dimensions and the modulus of elasticity at the appropriate temperature(s).

6.4.3 Strain-based design

The limit on equivalent stress recommended in **6.4.2.4** may be replaced by a limit on allowable strain, provided that all the following conditions are met.

a) The allowable hoop stress criterion (see **6.4.2.1** and **6.4.2.2**) is met.

b) Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.005 (0.5%).

c) The reference state for zero strain is the as-built state (after pressure test). The plastic component of the equivalent uniaxial tensile strain should be calculated using equation (8).

$$\varepsilon_p = \left\{\frac{2}{3}\left(\varepsilon_{pL}{}^2 + \varepsilon_{ph}{}^2 + \varepsilon_{pr}{}^2\right)\right\}^{0.5} \tag{8}$$

This analysis can be performed conservatively by assuming a linearly elastic – perfectly plastic stress/strain curve. Other, more realistic stress/strain curves may be used. However, it is essential that the assumed curve is validated as being conservative by material stress/strain curves from the manufactured pipe.

d) Any plastic deformation occurs only when the pipeline is first raised to its maximum operating pressure and temperature, but not during subsequent cycles of depressurization, reduction in temperature to the minimum operating temperature, or return to the maximum operating pressure and temperature.

This should be determined via analytical methods or an appropriate finite element analysis. The analysis should include an estimate of the operational cycles that the pipeline is likely to experience during the operational lifetime.

e) The D_o/t_{nom} ratio does not exceed 60.

f) Axial or angular misalignment at welds is maintained within defined tolerances.

g) A fracture analysis is carried out in accordance with **6.4.5**.

h) A fatigue analysis is carried in accordance with **6.4.6**.

i) The weld metal yield stress matches or overmatches the longitudinal yield stress of the pipe.

j) For welds where allowable defect sizes are based on an ECA, UT supplements radiographic testing, unless automated ultrasonic testing (AUT) is performed.

k) Additional limit states are analysed as follows:

1) bending failure resulting from application of a moment in excess of the moment capacity of the pipe;

2) ovalization – distortion of the pipe wall associated with bending to high strain levels (see **6.4.4.2** and Annex G);

3) local buckling (see **6.4.4.1** and Annex G);

4) global buckling – lateral or upheaval buckling due to overall axial compression (see **6.4.4.1** and Annex G).

Plastic deformation reduces pipeline flexural rigidity; this effect can reduce resistance to upheaval buckling and should be checked if upheaval buckling might occur. The effects of strain localization should be taken into account in the strain-based design.

NOTE Strain localization is associated with discontinuities in stiffness of the pipeline (bending or axial) and can therefore develop in the following locations:

- *changes in wall thickness;*
- *buckle arrestor locations;*
- *locally thinned regions, e.g. due to corrosion;*
- *field joints and coatings;*
- *welds, due to under matching of the strength of the weld.*

6.4.4 Buckling

6.4.4.1 General

The following buckling modes should be taken into account:

a) local buckling of the pipe wall due to external pressure, axial tension or compression, bending and torsion or a combination of these loads (see **G.1**). For fabrication processes which introduce cold deformations giving different strength in tension and compression, a fabrication factor, α_{fab}, should be determined;

NOTE 1 Guidance on the selection of a suitable fabrication factor is given in DNV-OS-F101:2013, Section 5.

b) propagation buckling due to external pressure, following the formation of local buckles or localized damage (see **G.2**);

c) restrained pipe buckling due to axial compressive forces, induced by high operating temperatures and pressures. This can take the form of horizontal snaking of pipelines, or vertical upheaval of trenched or buried pipelines (see **G.3**).

NOTE 2 The formulae given in Annex G define one approach to analysis. Alternative approaches are available and may be used where justified.

NOTE 3 To supplement the above methodology, the approaches defined within DNV-OS-F101 and DNV-RP-F110 may be adopted.

In all buckling analyses, the nominal wall thickness should be used.

6.4.4.2 Ovality

Ovality, or out-of-roundness, of pipes or a section of pipeline that could cause buckling or interference with pigging operations should be avoided.

NOTE 1 In some situations, where loading is dominated by bending, buckling might not occur but unacceptable levels of ovalization can result.

*NOTE 2 Ovalization may be calculated in accordance with **G.4** in the absence of a more rigorous evaluation.*

6.4.4.3 Coatings

Any beneficial effect of weight coating or insulation coating on buckling should not be taken into account in an analysis, unless analytical and experimental evidence is provided that indicates its effectiveness in providing additional stiffness.

6.4.4.4 Controlled deformation

Internal pressure and temperature can lead to transverse movements if the pipeline is not restrained, e.g. by burial. For exposed pipes in contact with the seabed, lateral movement is more likely and analysis for snaking and buckling should be performed. For buried pipelines, upheaval buckling analysis should be performed (see **6.4.4.5**).

*NOTE Annex G, **G.1** gives information on the critical strain limits. **G.1.7** provides a conservative estimate of the bending strain.*

6.4.4.5 Upheaval buckling

For exposed pipelines in contact with the seabed, lateral buckling can develop at relatively low levels of effective compression and checks should be carried out to demonstrate the pipeline's fitness for purpose.

An upheaval buckling design should demonstrate integrity of the buried pipeline with an overall agreed safety margin, taking into account the variability of all design parameters. The design should establish cover levels along the route taking into account the as-laid vertical, out-of-straight pipeline profile and the long-term and short-term characteristics of the cover material. Additionally, the stress/strain levels along the pipeline should be shown to be within allowable limits.

The effect of soil liquefaction should be taken into account.

6.4.5 Fracture

6.4.5.1 Fracture control

A pipeline should be designed to prevent brittle and ductile fracture.

*NOTE 1 The principal means of fracture control is by the selection of materials with adequate toughness through notched bar impact testing (see **8.2.5**).*

The material properties should be in accordance with **8.2.5** such that brittle fracture initiation or propagation does not occur, and that ductile fracture propagation is limited in length.

NOTE 2 Pipelines conveying a gas or a volatile liquid are susceptible to long running fractures (also known as propagating fractures). Toughness requirements for preventing long running fractures are given in BS EN ISO 3183:2012, Annex G.

6.4.5.2 Engineering critical assessments (ECA)

Weld flaw acceptance criteria may be based on workmanship acceptance levels or fitness-for-service limits, determined by either an ECA, or segment or full-scale testing. Fitness-for-service limits should take into account all static and cyclic (dynamic) loading that occurs during installation and operation. It should be demonstrated that fabrication flaws in the weld metal and heat-affected zone (HAZ) will not cause failure during installation or operation.

ECA should be conducted in accordance with BS 7910. The equations of BS 7910 are potentially non-conservative for strain-based design (>0.4% strain). In this case assessment should be confirmed by numerical simulation [finite element analysis (FEA) crack modelling]. If necessary, account should be taken of relevant results of full scale pipe tests, with pre-cracked girth welds, subjected to internal longitudinal strain and internal pressure.

NOTE 1 Guidance on conducting an ECA of pipeline girth welds is given in DNV-OS-F101:2013, Appendix A and DNV-RP-F108.

NOTE 2 An ECA is not normally required if the maximum total strain is less than or equal to 0.4%.

NOTE 3 Full scale testing is time consuming and complex to produce a statistically significant amount of data. ECA based on small scale (segment) tests is the main method.

ECA requires fracture toughness testing of representative welds to determine the fracture toughness of the weld and HAZ. The fracture toughness should be determined under representative environmental and service conditions. Fracture toughness testing should be conducted in accordance with BS EN ISO 15653 and BS 7448 as appropriate.

NOTE 4 BS 7910 gives guidance on the fracture toughness testing required for an ECA. DNV-OS-F101 and DNV-RP-F108 give guidance on testing pipeline girth welds.

6.4.6 Fatigue

6.4.6.1 General

All cyclic stresses due to pressure, thermal, or external loading, occurring during the entire life of the pipeline, should be taken into account when establishing the predicted significance or effect of fatigue.

In the assessment of stress ranges, the effect of construction activities that can cause stress concentrations should be taken into account.

All cyclic stresses between the threshold limit and the MAOP should be addressed (see ASTM E1049).

NOTE Typical sources of cyclic stresses include:

- *transportation, installation and testing activities;*
- *dynamic stresses (wind, waves, currents, vortex shedding);*
- *pulsation-induced vibration (at or near stations, reciprocating pumps and compressors);*
- *vibrations caused by surge and product flow;*
- *full stress cycles (start-up to shutdown cycles);*
- *fluctuations in operational (pressure and thermal) cycles;*

- *external thermal stress cycles (above-ground pipelines);*
- *earthquakes and ground movements.*

6.4.6.2 Fatigue life

The fatigue life of a pipeline is determined from the total number of full stress cycles together with the number of equivalent stress cycles (i.e. range of stress cycles that are expected or experienced by the pipeline) which could cause fatigue failure. Pipelines should be designed to provide a fatigue life that exceeds the proposed design life of the pipeline.

The need for a fatigue analysis depends upon the number and value of stress cycles predicted to occur over the operational life of the pipeline and should be assessed in accordance with **6.4.6.3**. In the case of revalidation it should be based on the actual number and known stresses experienced by the pipeline, plus the predicted life. Where required, the fatigue analysis should be carried out in accordance with **6.4.6.4**.

6.4.6.3 Assessment of need for fatigue analysis

Any engineering assessment undertaken to revalidate a pipeline for a change of operating conditions, including an extension of the design life, should include an assessment of the fatigue life.

A simplified assessment should be carried out to establish whether a pipeline fatigue analysis is required. A fatigue analysis is not required if either:

a) the maximum hoop stress cycle experienced by the pipeline is less than 35 N/mm^2; or

b) the system designed can be shown to replicate closely a previously analysed acceptable design.

The 35 N/mm^2 criterion should not be used for girth welds or circumferential flaws.

NOTE 1 Fatigue of girth welds depends mainly on the longitudinal stress range rather than hoop stress range.

NOTE 2 Additional guidance on the requirement for a fatigue analysis can be obtained from:

- *ASME B31.3 and ASME BPVC-VIII-1 for pipelines designed in accordance with ASME standards;*
- *PD 5500:2012+A3, Annex C, which includes criteria for establishing whether a detailed fatigue analysis is required, and gives guidance on how to conduct a fatigue analysis;*
- *DNV-RP-F105 for pipeline span and riser fatigue assessment.*

BS EN 13480-3 and PD 5500 may be used in combination with BS 7608 for the appropriate equivalent material S–N curves.

6.4.6.4 Fatigue analysis

A fatigue analysis should be carried out to determine the fatigue life of the pipeline unless shown otherwise in **6.4.6.3**.

NOTE 1 The fatigue life is dependent upon the number and range of stress cycles that are expected to occur, and the maximum size of defect that can exist.

The fatigue analysis should be carried out using one of the standards listed in Note 2 to **6.4.6.3** together with an appropriate *S–N* curve (i.e. one that is specific to the material type, environment, frequency, workmanship and quality achieved during construction).

Account should be taken of stress concentrations owing to pipe ovality, misalignments, material type change and local shape deviations.

The fatigue analysis method, material properties and other input data used in the assessments should be documented and fully justified.

The actual cycles accumulated during operation should be recorded and maintained for future evaluation of the pipeline.

Where an appropriate *S–N* curve is not available then an *S–N* curve should be produced through fatigue testing or a fracture mechanics based fatigue analysis should be conducted.

NOTE 2 The S–N curves in BS 7608 might not be applicable to low cycle, high strain fatigue loading that might be encountered in a strain-based design.

The *S–N* curves recommended in BS 7608 have been developed for application to normal structural joints which are in general accessible to inspection and have a level of redundancy. Pipelines are non-redundant structures and accessibility for inspection is limited, so an appropriate factor of safety should be included on the fatigue life predicted using the *S–N* technique.

The safety factor should be selected and justified as part of the design fatigue analysis, taking into account accessibility for and reliability of inspection, uncertainty in the number and value of stress cycles and the severity of consequences of failure.

NOTE 3 Safety factors typically applied to pipeline fatigue design analysis range from 1 for non-hazardous, non-critical pipelines to between 3 and 10 for hazardous pipelines.

6.4.6.5 Re-qualification of pipeline design

A fatigue analysis should be carried out to re-qualify the pipeline if an extension to the current design life or a change in the duty of the pipeline (i.e. change in product or service causing a modification which raises the internal pressure, or introduces more pressure cycles) is proposed.

The analysis should demonstrate that the largest defect in the system will not grow through fatigue to failure during the re-qualified design life of the pipeline. The largest defect size should be determined through non-destructive testing (NDT) methods such as the use of an in-line inspection tool or, if necessary, a repeat hydrotest (conducted at a level determined by the largest defect that may be accepted). Any NDT approach should be capable of detecting and reliably sizing crack-like defects, particularly in the longitudinal direction.

Mid-wall (lamellar) defects should be taken into account in the fatigue analysis, and a specific fitness-for-purpose assessment of these defects undertaken.

NOTE API RP 579 contains guidance on the assessment of dents, gouges and laminations.

6.5 Design of flexible pipelines

Flexible pipelines are proprietary items that do not lend themselves readily to direct application of the methods set out in **6.4**, although equivalent design checks for pressure containment, in-place strength, buckling and fatigue should still be carried out. Their component design should be based on a recognized standard such as API RP 17B or BS EN ISO 13628-2.

The design of flexible risers should be in accordance with appropriate standards such as API RP 17B and API 17J.

6.6 Bundles and multiple pipelines

6.6.1 General

6.6.1.1 Bundles

*COMMENTARY ON **6.6.1.1***

A strapped bundle piggy-back comprises one or more pipelines strapped to the main pipeline. The main pipeline is usually the only one laid under tension and it supports the strapped-on pipelines. An encased bundle comprises one or more pipelines fabricated within a sleeve, also known as a carrier pipe.

The characteristics of the smaller line of a bundle, and its impact on the bundle, should be taken into account at the design stage.

6.6.1.2 Sleeve pipe

The sleeve should be designed to fulfil one or more of the following functions:

a) provide buoyancy during installation;

b) control stresses and stiffness during installation;

c) protect internal lines from accidental loads;

d) provide containment for the corrosion prevention medium;

e) provide primary corrosion protection to the internal lines;

f) provide submerged weight and stability to flowlines with foam insulation.

NOTE The sleeve may also be designed for carrying an internal pressure as a means of leak detection and containment from a pressurized internal pipe.

6.6.1.3 Additional bundle components

The following components, where applicable, should be taken into account when designing a bundle:

a) tow/trailing head at the ends of the bundle, which may also incorporate alignment devices and termination facilities;

b) trim/weight chains;

c) bulkheads;

d) spacers;

e) thermal insulation systems.

*NOTE Flowlines might require thermal insulation. This can take the form of either a dedicated insulation coating or provision of an insulating medium in the annulus (see **8.9**).*

6.6.1.4 Stress

The combined section properties of all pipelines within the bundle configuration, including the sleeve pipe, should be used for installation and functional stress assessment. Component and combined stresses for all elements of a bundle should be calculated in accordance with **6.4**. The calculation of longitudinal strain and associated stresses should take account of the interconnection between all components.

When integral or external buoyancy is provided to assist installation, the effect of that buoyancy on bundle stressing should be assessed for installation and functional conditions.

6.6.2 Fabrication and installation

6.6.2.1 Fabrication and launch considerations

The following fabrication and launch factors should be taken into account in the design:

a) fabrication/launch site, including:

   1) onshore launch site topography;

   2) type and condition of launchway;

   3) nearshore launch site bathymetry;

   4) provision for nearshore extension of launchway;

   5) seabed soil conditions;

   6) nearshore environmental conditions;

b) launch forces, including:

   1) static and dynamic friction between bundle and launchway;

   2) environmental forces on partially or completely launched bundles.

6.6.2.2 Tow considerations

The following tow factors should be taken into account in the design:

a) for an on-bottom tow:

   1) static and dynamic friction variations along the route due to seabed soil conditions (see **H.2.7**), and the ability of the coating to resist abrasion;

   2) extent of stability provided by bundle against current and wave forces (both nearshore and offshore);

   3) bathymetry along the corridor of the tow route;

   4) towing tension conditions and drag forces;

   5) towhead lift-off;

   6) vessel configuration;

   7) seabed debris and existing pipelines and cables;

b) for an off-bottom, mid-depth, near-surface and surface tow:

   1) effect of current and wave forces (see Annex H);

   NOTE The design environmental loads may be reduced where the tow procedures and surveyed route corridor allow the bundle to be manoeuvred into an orientation that minimizes the effect of severe weather.

   2) type and location of buoyancy provided;

   3) drag on trim/weight chains resulting from current and wave forces, momentum, and contact with the seabed;

   4) bundle configuration during tow, with reference to tow vessel positioning, and tow tension in combination with drag and lift forces.

The effect on stress levels of bundle tie-in manoeuvring should be taken into account in conjunction with environmental loading, which should be determined in accordance with Annex H.

The effects of changes of buoyancy during installation should be taken into account.

6.6.3 Loads and load combinations

The design of bundled pipelines should take into account the same loads and load combinations as recommended in **F.2**.

The following factors should also be taken into account:

a) for construction:

   1) forces due to onshore site topography;

   2) forces due to launchway configuration;

   3) pull forces during launch;

   4) tow forces;

   5) bending between spacers;

   6) environmental loadings;

b) for operation:

   1) temperature and pressure expansion forces due to interconnection of pipelines and sleeve;

   2) spanning between spacers.

6.6.4 Design factors and stress

The following factors should be taken into account:

a) design factors;

   NOTE 1 Provided that suitable stability is established against environmental loading, then encased pipelines between pressure bulkheads (but not risers) are deemed to belong to the seabed section for the application of design factors (see Table 2).

b) stress evaluation.

Account should be taken of the installation method and the relative strengths of all pipelines in the bundle.

*NOTE 2 See also **6.4.1**, **6.4.2** and **6.4.3**.*

6.7 Pipe-in-pipe systems

6.7.1 General

6.7.1.1 Outer pipe

In a pipe-in-pipe system, the outer pipe contributes to the pipe-in-pipe structural performance and should be taken into account at the design stage.

The sleeve should be designed to fulfil one or more of the following functions:

a) provide primary corrosion protection to the inner line;

b) protect the internal line from accidental loads;

c) contain insulation material. The behaviour of the insulating material should also be taken into account.

6.7.1.2 Additional pipe-in-pipe components

The pipe-in-pipe design should include the following components where necessary:

a) intermediate bulkheads to provide watertight compartment separation diaphragms and/or waterstops positioned within the pipe-in-pipe annulus;

b) spacers to ensure concentricity of inner pipe within outer pipe.

NOTE It might also be necessary to provide "lay-stops" to provide mechanical connection between inner pipe and outer pipe during the installation operation.

6.7.1.3 Stress

The combined section properties of inner pipe and outer pipe within the pipe-in-pipe system should be used for installation and functional stress assessment. Component and combined stresses for all elements of the bundle should be calculated in accordance with **6.4**.

The calculation of longitudinal strain and associated stresses should take account of the interconnection between the inner and outer pipeline, including the effect of the insulation material.

6.7.2 Loads and load combinations

The design of pipe-in-pipe systems should take into account the same loads and load combinations as recommended in **F.2**.

The following should also be taken into account:

a) for installation:

   1) forces between inner pipe and outer pipe during installation;

   2) bending between spacers;

b) for operation:

   1) temperature and pressure expansion forces due to interconnection of inner pipe and outer pipe;

   2) spanning between spacers.

6.8 Stability

6.8.1 Approach

6.8.1.1 General

The pipeline should be designed to be stable during construction and operation. Where movement is permitted this should not adversely affect the integrity of the pipeline.

The stability analysis should take into account:

a) hydrodynamic forces resulting from the action of near-seabed, wave-induced and steady currents on the pipeline;

b) lateral soil forces;

c) vertical stability;

d) historic stability of seabed;

e) axial forces in the pipeline, where appropriate.

*NOTE In most cases, a two-dimensional analysis method (see **6.8.1.2**) is acceptable for determining the stability of a pipeline. In areas where excessive stabilization is predicted, a more complex three-dimensional analysis method (see **6.8.1.3**) may be used.*

6.8.1.2 Two-dimensional analysis method

If the two-dimensional analysis method is used (see Figure 4), the lateral soil friction coefficient, μ, should be greater than or equal to the stability safety factor, S_F, as shown in equation (9).

$$\mu(W_S - F_L) \geq S_F(F_D + F_I) \tag{9}$$

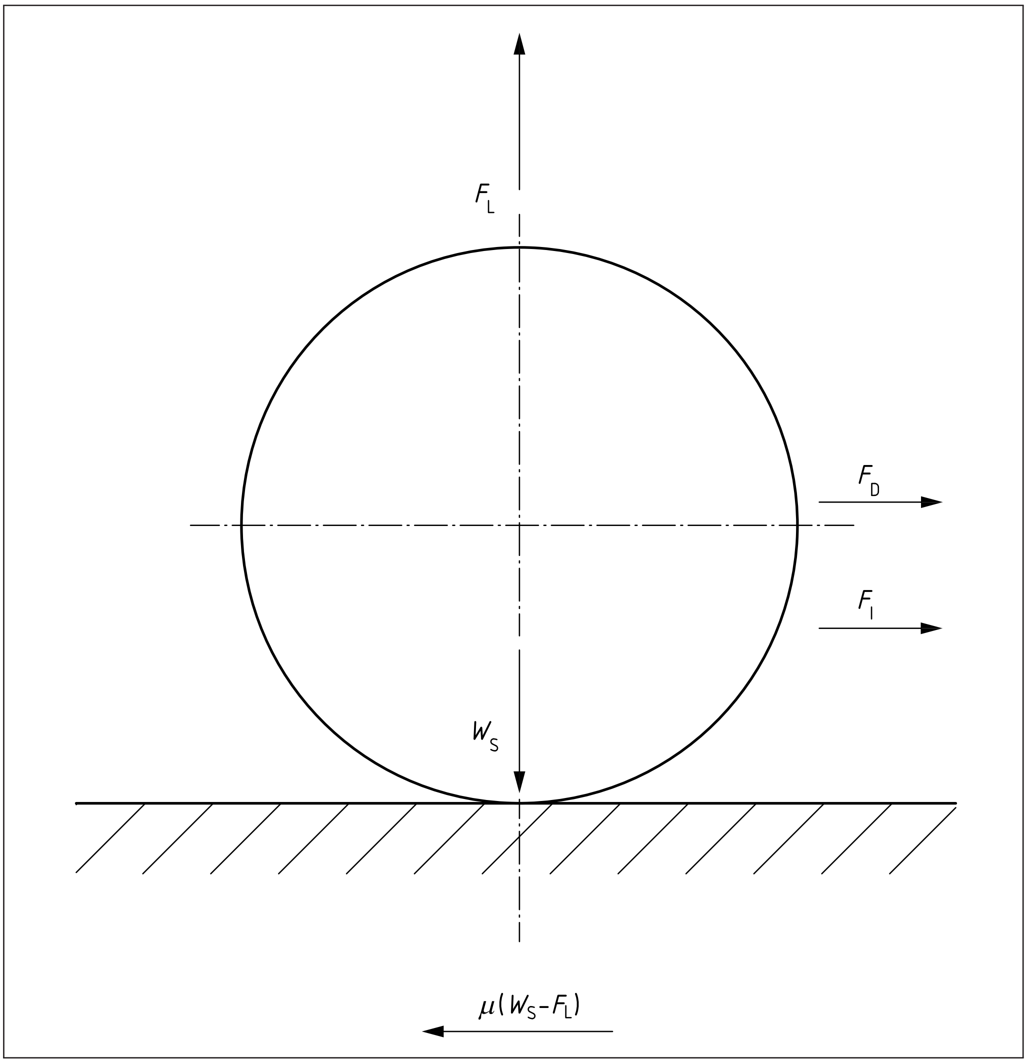
NOTE 1 A value of 1.1 is commonly used for the safety factor. In exceptional circumstances, where environmental conditions are known to a high degree of certainty, a lower value can be applied.

NOTE 2 Guidance on the derivation of these parameters is given in Annex H.

The influence of wave phase angle on F_L, F_D and F_I should be taken into account when determining the most unfavourable combination of forces acting upon the pipeline.

NOTE 3 To supplement the above methodology, the approaches defined within DNV-OS-F101 and DNV-RP-F109 may be adopted.

Figure 4 **Two-dimensional stability analysis method**

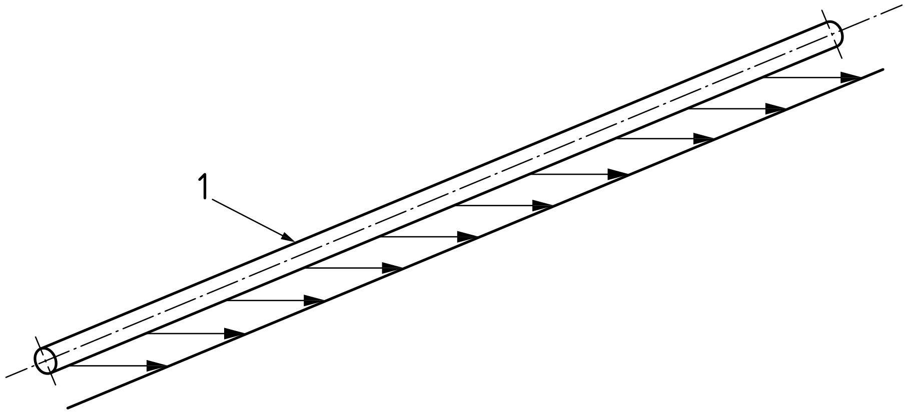


6.8.1.3 Three-dimensional analysis method

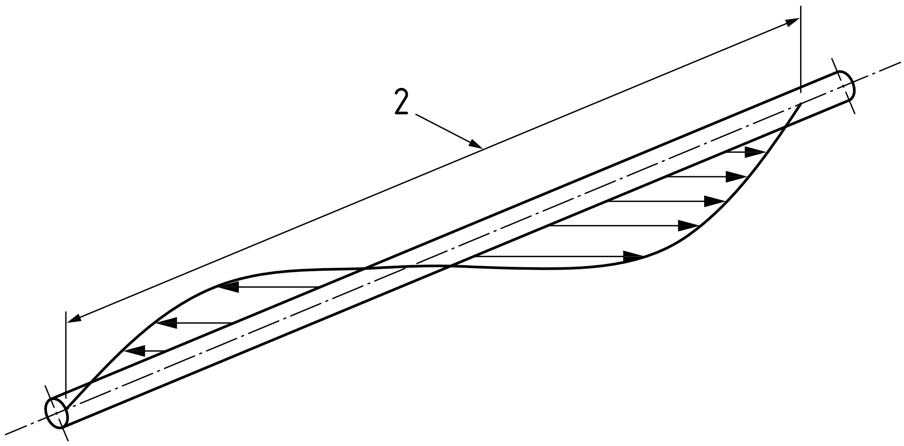
If the three-dimensional stability analysis method is used (see Figure 5), allowable movements should be based on acceptable stress levels and fatigue. Account should also be taken of the possible loss of concrete due to movement and damage to the pipeline by third-party activity.

NOTE The approaches defined in DNV-OS-F101, DNV-RP-F109 and the American Gas Association publication Submarine pipeline on-bottom stability *[29] may also be used.*

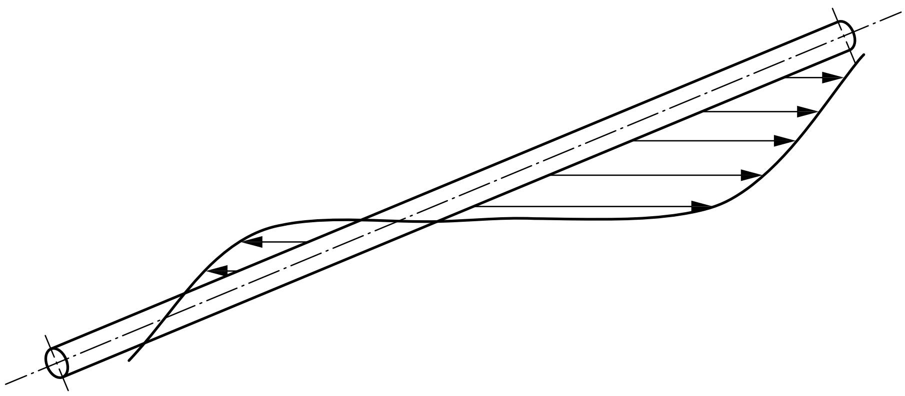
Figure 5 **Three-dimensional stability analysis method**



a) Force due to steady current



b) Force due to short crested waves



c) Combined force due to steady current and short crested waves

Key

1 Pipeline

2 Wave crest length

6.8.2 Submerged weight

When calculating the submerged weight the following factors should be taken into account:

a) the total mass of a steel pipeline including all attachments and contents;

b) the increase in mass resulting from water absorption;

*NOTE For subsequent analysis cases, water absorption may be taken into account (see **8.9**).*

c) the specific gravity of the surrounding medium.

6.8.3 Hydrodynamic forces

Hydrodynamic forces should be determined in accordance with Annex H.

6.8.4 Soil instability and vertical stability

6.8.4.1 Soil characteristics

Soil characteristics that should be established include:

a) soil type;

b) shear strength;

c) grain size distribution;

d) specific weight.

6.8.4.2 Soil instability

Suitable stability enhancement methods (see **6.8.4.4**) should be used when a pipeline is routed through an area of potential soil instability.

NOTE Soil instability can be initiated by:

a) seismic activity;

b) wave action and seabed current;

c) overloading due to submerged weight of pipeline;

d) deposition or scouring of seabed soil material;

e) pipeline trenching;

f) pockmark and gaseous emissions;

g) slope fail.

6.8.4.3 Vertical stability

When assessing the vertical stability of a pipeline the following should be taken into account:

a) the specific weight of the soil;

b) the soil shear strength;

c) seabed liquefaction.

If sinking is likely to occur, then the following adverse effects on the pipeline should be taken into account:

1) overstressing of the pipeline due to uneven sinking;

2) obstruction of future access to the pipe.

6.8.4.4 Stability enhancement methods

When enhancing stability, one or more of the following methods should be used:

a) increasing wall thickness;

b) concrete weight coating;

c) trenching;

d) piling anchors;

e) installing concrete saddles;

f) installing gravity anchors;

g) installing suction anchors;

h) installing flexible mattresses;

i) using grout bags;

j) rock placement;

k) artificial seaweed mats;

l) pipe-in-pipe.

When determining the type, holding capacity (horizontal and vertical) and spacing of additional pipeline restraint devices, the following factors should be taken into account:

1) overall equilibrium of the pipeline;

2) loads transferred between the pipeline and individual restraint devices;

3) direct hydrodynamic loads imposed on individual restraint devices;

4) horizontal and vertical bending stresses induced in the pipeline;

5) possibility of flow-induced vibration of the pipeline sections between individual restraint devices;

6) possible consequences of pipeline expansion, including buckling of the pipeline between individual restraint devices and additional lateral loads on the restraints (see Annex G);

7) risk of pipeline damage during installation of restraint devices;

8) possibility of inducing scour around and between restraints.

6.8.5 Trenching and partial burial

6.8.5.1 Trenching

Trenching can enhance pipeline stability by the following means:

a) trench walls inhibiting sideways movement;

b) the trench tending to act as a sediment trap, leading to an accumulation of deposited soil around the pipe (natural backfill);

c) the trench side slopes providing some shelter from hydrodynamic forces.

NOTE 1 The effectiveness of the stability enhancement mechanisms is influenced by the depth, width and side slope angle of the trench.

These influences should be analysed, with allowance being made for uncertainties in predicting the actual trench profile.

NOTE 2 These may be analysed by inclusion of modified lateral friction coefficient in the pipe soil interaction model, and modified hydrodynamic coefficients.

6.8.5.2 Partial burial

Partial burial can enhance stability by the following means:

a) increased lateral soil restraint;

b) reduction in hydrodynamic forces.

6.8.5.3 Self-burial

Where knowledge of seabed conditions and historical stability indicates that self-burial to the required depth of cover is likely, self-burial can enhance artificial trenching or burial operations. The design should provide for artificial burial where burial is required and self-burial does not occur.

NOTE The distinction is normally made between self-burial resulting from sediment mobility, and pipeline sinking resulting from shear failure of the seabed soil.

6.9 Spanning pipelines

6.9.1 Geometry

The geometry and support conditions of a span should be defined with reference to the following:

a) end support conditions;

b) length of span;

c) profile of gap below the span;

d) end slope conditions;

e) adjacent spans.

NOTE For more detailed guidance on pipeline spanning, see DNV-RP-F105.

6.9.2 Evaluation

The span should be evaluated for the full range of loading conditions (see **6.3** and Annex F), and for interference with other legitimate users of the sea.

NOTE For assessment of pipeline interaction with trawl gear, see DNV-RP-F111. Guidance is also given in HSE publication OTH 561 [30].

Spans that are likely to interact should not be analysed individually.

6.9.3 Static analysis

The static analysis should take into account the allowable stress, or strain, criteria identified in **6.4.2** and **6.4.3** as appropriate and the potential for lateral instability.

Free spans can occur as a consequence of the seabed topography or scour action after a pipeline has been laid. In either case, they should be evaluated for both static and dynamic conditions, and if estimated stresses are in excess of those allowable, measures should be taken to reduce the effective span length.

6.9.4 Vortex shedding and fatigue

Pipeline or riser span oscillations induced by internal or external fluid flow should be taken into account. The design should either prevent pipeline oscillation or show the oscillations to be acceptable with respect to the following:

a) service considerations;

b) strength;

c) fatigue (see **6.4.6**);

d) coating integrity.

NOTE For guidance on cross-flow and in-line vortex-induced vibration fatigue in pipelines and risers, see DNV-RP-F105 and DNV-RP-F204.

6.10 Pipeline and cable crossings

6.10.1 General

Each crossing should be designed such that separation is maintained between the new pipeline and the existing pipeline or cable.

The mass of the new pipe should not be supported by the existing pipeline or cable, unless an interaction analysis can demonstrate that the integrity of the crossed line is not impaired, taking account of short-term and long-term settlement and overburden loads.

The crossing design should accommodate pipeline expansion effects.
The cathodic protection should be isolated.

6.10.2 Design

6.10.2.1 Consultation

At the initial stages of the design of a crossing there should be consultation with the operator of the existing pipeline or cable.

6.10.2.2 Pipeline route

Where possible, the route of each new pipeline should be selected such that:

a) the use of stacked pipeline or cable crossings is avoided;

b) the crossing angle is preferably greater than 30° and as close as possible to 90°.

6.10.2.3 Condition of existing system

The design of a crossing should be based on the following data on the existing system:

a) age and condition;

b) pipe/cable size and submerged weight;

c) burial or trenching details;

d) details of rockfill, mattresses, grout bags or protection/support structures;

e) coating type and condition;

f) details and condition of cathodic protection;

g) pipeline operating pressures and temperatures;

h) pipeline contents;

i) cable operating specification;

j) accuracy of as-surveyed data;

k) interaction with fishing gear during and following crossing construction.

6.10.2.4 Lowering the existing system

If the existing pipeline or cable needs to be lowered:

a) the design of the crossing should be based on the following environmental data:

   1) soils description;

   2) bathymetry and history of seabed mobility;

   3) bearing capacity of seabed;

   4) wave and current details and water depth;

   5) fishing and other marine activities;

b) a sufficient transitional length on each side of the crossing should be lowered such that pipeline bending is maintained within recommended stress levels and pipeline buckling is prevented (see **6.4**).

An assessment of the need to reduce the pressure in the existing pipeline during the lowering operation should be carried out.

6.10.2.5 Elevating new pipeline

The design of the elevated pipeline section should minimize free spans and should be assessed for upheaval buckling loads.

6.10.2.6 Support structures

Support and protective structures, ramps or separators should be designed to prevent scour. Any structure that is exposed, or could become exposed, on the seabed should be profiled to avoid snagging of fishing gear.

6.10.3 Installation

6.10.3.1 Notification

The crossing installation programme should be discussed and agreed with the operator of the existing pipelines or cables, who should be notified prior to mobilization for each of the pipelay and crossing activities.

6.10.3.2 Survey

The condition of the seabed and the installed facilities should be surveyed at the following stages of construction of a pipeline crossing:

a) after trenching or protecting the existing pipelines or cables and prior to crossing pipe installation;

b) after crossing pipe installation;

c) after completion of pipeline crossing including all support and protection structures.

6.10.3.3 Installation and survey tolerances

Installation and survey tolerances should be taken into account to ensure that the new pipeline can be accurately positioned over the central section of the prepared crossing.

6.10.4 Protection of crossings

The profile of the completed crossing should be such that light anchors and fishing gear are deflected smoothly over the top, and scour erosion and damage to fishing gear are avoided or minimized.

6.11 Leak detection

The designer should determine whether a leak detection system needs to be incorporated into the design of a pipeline. The method chosen for leak detection should be appropriate to and effective for the substance to be conveyed.

NOTE Typical leak detection methods include continuous mass balance of pipeline contents, detection of pressure waves, monitoring of rate of change of pressure and flow, and dynamic modelling by computer.

The leak detection system should be part of the overall pipeline management system, which should incorporate route inspection in accordance with **13.3.2**.

6.12 Fabricated pressure-containing components

If fabricated pressure-containing components are used, the design pressure should be equal to the internal design pressure of the pipeline.

The design should take account of static loading, transients during slug arrival, anchor and support requirements and the provision of sample points. When carrying out flexibility and stress analysis calculations, account should be taken of momentum and dynamic effects.

Fabricated pressure-containing components other than headers and manifolds generally should be designed in accordance with BS EN ISO 13628-15, PD 5500 or ASME BPVC-VIII-1.

7 Design – Landfalls, risers and tie-ins

7.1 Selection of location

In selecting the location for landfalls, risers and subsea tie-in connections (tees, wyes, etc.), account should be taken of:

a) tie-ins to existing facilities;

b) practicalities of construction (pipeline approaches);

c) hazards from other operational facilities;

d) safety of operations;

e) other marine activities;

f) public safety and the environment;

g) anticipated developments.

7.2 Landfalls

*COMMENTARY ON **7.2***

The landfall is generally that section of a pipeline that extends from the low water on the beach or nearshore area to a point onshore where normal onshore construction can be carried out.

The landfall extent is determined by the following features:

a) a different method of pipeline installation from that of the main offshore pipeline, required as a result of physical characteristics such as water depth, surf or inter-tidal zone conditions, topographic or geotechnical conditions or environmental impact considerations;

b) additional temporary or permanent engineering works, required to install the pipeline in the nearshore area;

c) *differing pipeline design requirements (e.g. levels of safety; lower stress factors than for offshore).*

Certain aspects of PD 8010-1 are also relevant to the shore area.

Principal methods of installation of landfalls (see ***7.2.2*** *and* ***10.17****) usually include installation of the pipeline for some distance above low water mark. Clause* ***7*** *is therefore also relevant to the portion of the pipeline above low water, where that portion is installed by the same method and in the same operation as the landfall.*

This guidance is also applicable to short nearshore pipelines.

7.2.1 General

7.2.1.1 Routeing

Routeing of a landfall should take into account the same general factors as the remainder of the submarine pipeline (see **6.3** and Annex E). Additional aspects that should be taken into account include:

a) environmental conditions caused by adjacent coastal features;

b) location of the landfall to facilitate installation;

c) feasibility of installation methods (see **6.10.3**);

d) environmental impact;

e) landline route;

f) the potential for future adjacent construction works or pipeline and cable installations;

g) consultation with third parties and the appropriate authorities.

7.2.1.2 Surveys

Survey information needed for a landfall is similar to that for the remainder of the submarine pipeline with respect to environmental, bathymetric and geotechnical data as described in **E.6**. Additional data that should be taken into account include the following:

a) investigations into transportation of seabed material and history of seabed level changes;

b) investigation of coastal erosion;

c) investigation of ground conditions;

d) presence of rock outcrops;

e) possible need to breach sea defence works.

7.2.2 Installation

There are several different installation methods that may be used (see **10.13**). The design should take into account the intended installation method and the following:

a) self-weight of the pipe;

b) loads imposed during installation;

c) period of installation.

7.2.3 Loads

A wave theory should be selected that is appropriate to the landfall zone (see Annex H) to determine the hydrodynamic loads. Account should be taken of the following:

a) refraction shoaling and breaking of waves in the nearshore area;

b) interaction with steady currents due to tide, surge and wave related onshore movement.

Where buoyancy aids are to be utilized during installation, account should be taken of the hydrodynamic forces imposed on the buoyancy aids and their effect on pipeline stability.

*NOTE See also **6.3** and Annex F.*

7.2.4 Design factors and stress evaluation

Design factors for the landfall should be as given in Table 2.

*NOTE See also **6.4.2** and **6.4.3**.*

7.2.5 Protection and stabilization

7.2.5.1 Pipeline protection

Pipelines in the landfall zone should be buried, unless a risk assessment demonstrates that burial is not necessary.

*NOTE See also **6.2**.*

7.2.5.2 Pipeline stabilization

The relatively short period of time during which the pipeline is exposed during installation may be taken into account for hydrodynamic forces through the use of lower return period waves in order to reduce the amount of weight coating.

Where restraints or anchors are needed, the method of installation should take account of the environmental conditions prevailing in the nearshore area.

7.2.5.3 Pipeline burial

The burial depth should be such that the pipeline is not likely to become exposed during its life. Minimum cover should also be related to accidental loads (see **F.7**).

7.3 Tie-ins and risers

7.3.1 General

Offshore tie-ins and risers are critical to an offshore installation and its exposure to environmental loads and mechanical service connections, and the design should be subjected to a full stress analysis. Due to the importance of the safety of offshore installations, offshore risers are subject to lower design factors than the main pipeline as given in Table 2. Specific attention should be paid to slam loading and corrosion protection in the splash zone (see **7.3.6**). When selecting design stress values, the design should take into account that there might be a reduced inspection capability during operations.

Induced movements and velocity amplification can also be pertinent to riser design, especially when risers are closely spaced, and should be taken into account. The potential for platform settlement should be addressed (see **7.3.3**).

*NOTE Riser protection is important and may be enhanced by location of the riser within the supporting structure (see **7.3.6**). It might be expedient for the riser and spool pieces to be pressure-tested separately from the pipeline.*

7.3.2 Expansion evaluation

7.3.2.1 General

The design should take into account the effect of expansion or contraction under the following conditions:

a) operating conditions;

b) hydrotest conditions;

c) shut-in wellhead pressure.

Pipeline expansion should be controlled using one of the following methods:

1) axial anchoring systems;

2) expansion offsets;

3) containment within a sleeve;

4) snaked pipeline routeing.

7.3.2.2 Seabed friction factors and soil restraint

Where longitudinal friction factors cannot be determined from soil survey data, the minimum values given in Annex H, Table H.1 should be used for guidance. Increased frictional resistance resulting from pipeline embedment should be taken into account.

Frictional resistance to expansion can be increased by engineered backfill. The design of the backfill should take into account the uncertainties inherent in its method of placement.

7.3.2.3 Temperature changes

The heat loss through the pipeline system should be taken into account when undertaking stress calculations.

NOTE Gas pipelines can cool to below ambient temperatures due to the Joule-Thomson effect.

7.3.3 Loads

7.3.3.1 Installation loads

Installation loads should include wave slam, self-weight during lifting, rigging loads, and dynamic amplification factors.

*NOTE See also Clause **10**.*

7.3.3.2 Environmental loads

Environmental loads should be determined in accordance with Annex H or with an alternative approach that can be shown to give equivalent results. In addition, the following loads should be taken into account:

a) platform displacements, including long-term settlement;

b) scour effects that can occur around any structure on the seabed;

c) vortex shedding (see **6.9.4**).

Velocity amplification effects should be taken into account where risers are located close to structural members (see **H.1.6**).

The effects and interaction of loads applied to riser support structures should also be taken into account.

NOTE Horizontal sections of risers in the splash zone are subject to wave slam loads. Wave slam loads can also be applied to horizontal riser support members.

7.3.3.3 Dynamic forces induced by pipeline operations

Dynamic loads due to pipeline operations should be taken into account. Local loads can occur as a result of discontinuities in the flow. The combination of such loads should take account of their frequency of occurrence.

The effect of cyclic loads due to fluctuations in operating pressure and flow rate should be taken into account.

7.3.3.4 Deadweight loads

Deadweight loads should include the mass of:

a) topside pipework;

b) valves;

c) any fittings in the risers;

d) anodes.

NOTE The SLARP JIP is developing guidance and analysis methods covering slug loadings on tie-in spools.

7.3.3.5 Accidental loads

Account should be taken of:

a) routeing of risers (see **7.3.6.1**);

b) providing additional mechanical protection in hazardous areas.

7.3.4 Design factors and stress evaluation

Design factors for the risers and tie-ins should be as given in Table 2.

*NOTE For certain riser installation conditions, strain criteria may be applied in accordance with **6.4.3**.*

7.3.5 Tie-in spool design

7.3.5.1 Flexibility

Where the movement of the expansion spool is restricted, this should be taken into account when evaluating the spool flexibility. In the absence of specific data, the values of friction factor given in Annex H, Table H.1 should be used.

NOTE The main purpose of the expansion spool is to limit the loads transmitted to the riser due to movement of the pipeline. The stresses in the spool and loads transmitted to the riser are dependent on the frictional resistance of the seabed.

7.3.5.2 Stability

Local lateral stability under environmental loading cannot be achieved, as it is necessary for the expansion spool to move relatively freely. Where spool displacement is allowed to occur, a stress analysis should be carried out under maximum environmental conditions to ensure that the spool will not be overstressed.

There should always be vertical stability, i.e. the submerged weight of the spool should be greater than the maximum lift force acting on the spool.

7.3.6 Riser design considerations

NOTE Risers are more likely than other parts of the pipeline to be subject to material loss due to erosion and corrosion, and the protection of riser sections in the splash zone is essential. External inspection techniques are limited as some areas are beyond the normal operating limits of divers or remotely operated vehicles (ROVs).

7.3.6.1 Riser location

Risers should whenever possible be located inboard of the structure, minimizing the possibility of damage due to impact by marine vessels and dropped objects. Risers should be routed away from accommodation facilities and safety zones. Riser location should take into account the protection recommendations given in **7.6.3**.

7.3.6.2 Riser supports

The design and location of riser supports should take into account:

a) loads in the supports and adjacent structure;

b) static stress in the riser;

c) vortex shedding (see **6.9.4**);

d) bar buckling;

e) fatigue;

f) access for inspection;

g) thermal expansion;

h) platform settlement.

Riser supports should not be placed in the splash zone.

7.3.6.3 Bundled risers

Bundled risers should be either:

a) installed in a sleeve or J-tube (see **7.4**); or

b) connected together but uncased.

Account should be taken of the potential effects of the failure of a riser on other risers or umbilicals within the bundle.

Bundled risers should be designed in such a way that they can be inspected and any leaks within the sleeve can be detected.

Interaction effects between bundled risers should be taken into account, including:

1) axial expansion forces;

2) differential expansion of bundled components.

Interaction effects between all components should also be taken into account.

7.3.7 Fatigue of risers

Fatigue analysis of risers should be performed in accordance with **6.4.6**. The degree of fixity imposed by the riser supports on the riser should be assessed in the evaluation of local stresses used in determining the fatigue life.

7.4 J-tubes and sleeves

7.4.1 Configuration and routeing

The following should be taken into account in the choice of J-tube or sleeve arrangement:

a) riser support requirements;

b) possible requirements for future risers;

c) access to entry point at bottom of J-tube to facilitate a direct pull;

d) diameter of J-tube;

e) minimum radius of J-tube.

7.4.2 Loadings

J-tubes and sleeves should be treated as structural attachments to a fixed offshore structure, and should be designed in accordance with the design code for the structure.

7.4.3 Design

The design of J-tubes and sleeves should take into account:

a) possible buckling of the J-tube due to pull-in loads (see Note);

b) suitability of the J-tube diameter and bend radius for the anticipated riser;

c) fatigue due to environmental and other loadings;

d) security of attachments to structure;

e) gas permeation from flexible risers;

f) support of pipeline between J-tube exits and seabed;

g) the monitoring, retention and replenishment of an annulus inhibition system;

h) the need to detect leaks.

NOTE The analysis of J-tube buckling needs to take into account the effect of the large eccentricity present in the bend. Arch buckling theory may be employed. See Theory of elastic stability *[31]. FEA methods may also be used.*

7.5 Subsea connections and valves

7.5.1 Connection design

7.5.1.1 Connection types

Connections to a subsea pipeline should be made using one of the following:

a) tee;

b) Y-piece;

c) tapping.

7.5.1.2 Tees

Tees should be meet the general recommendations for fittings given in **8.3.6.1**. Typical types of pipeline tees are:

a) plain tee;

b) barred tee;

c) full flow sphere tee.

If plain tees are used, the relative diameters of the branch and main line should be taken into account. Full flow sphere tees minimize the tendency of spherical pigs to expand into or be bypassed at the tee branch. The bars of barred tees should not protrude into the bore of the main line, and the bars should be sized and spaced to prevent interference with the pig run.

7.5.1.3 Y-pieces

Connection by Y-piece allows unidirectional pigging of the main and branch pipeline. The internal geometry of a Y-piece should be designed such that the design flow conditions can be achieved and that it can be pigged. Both branches of the Y-piece should have the same diameter if it is to be pigged conventionally.

7.5.1.4 Tapping

NOTE Tapping is a method of connection into an operational pipeline.

One of the following two techniques should be used for tapping:

a) hot tapping: where the pipeline can remain at operational pressures throughout the tapping process;

b) cold tapping: where the pipeline pressure is reduced to ambient conditions and the product removed before the tapping process.

Tappings should be subjected to NDT, strength and leak-testing during installation.

7.5.2 Valve arrangements at subsea connections

The design of the valve arrangements at subsea connections should take into account:

a) the number of branches to be connected to the main pipeline;

b) the provision of a valve or valves in the main pipeline;

c) the provision of a valve or valves in the branch(es);

d) arrangements for controlling the direction of flow in the main pipeline and branches;

e) whether the main pipeline is likely to be operational when the branch connection is made, and its operational pressure and contents;

f) the method of connecting the branch to the main pipeline and provisions for the safety of divers;

g) arrangements for pressure-testing, de-watering (and possibly drying) and commissioning of the branch line;

h) the provision of pigging or sphering facilities in the main pipeline and the branch;

i) provisions for maintaining or replacing the valve and its actuator.

7.5.3 Valve selection

Valves to permit the passage of pigs should be full bore and without internal obstructions likely to restrict or damage the pig.

Subsea valve and valve control systems should be protected (see **7.6**). When selecting valves, the following issues should be taken into account:

a) system operating and hydrostatic pressure;

b) all fluids to which the valve might be exposed;

c) service temperatures;

NOTE 1 This can include low internal temperatures due to system depressurization.

d) service life;

e) duration of pre-commissioning period;

NOTE 2 Valves can remain static in open or closed positions for long periods but have to be able to function on demand.

f) presence of debris from product or construction activities;

g) system pigging;

h) in situ seal injection or replacement;

i) installation method;

j) ability to test the valve performance;

k) internal galvanic corrosion;

l) reliability;

m) maintenance aspects;

n) actuation;

o) integrity and achievement of isolation;

p) any restrictions or requirements for differential pressure levels across valves during operation.

Ball, check, gate and plug valves should meet the requirements of ISO 14313.

Bleed and vent valves should take into account the practicalities and limitations of subsea operation.

The face-to-face dimension of flanged valves should be increased from that stated in the appropriate standard when necessary to accommodate specialist bolt tightening equipment. In-line valves should allow the passage of inspection devices.

7.5.4 Actuators

When selecting and designing valve control systems, the following factors should be taken into account:

a) type of actuator;

b) valve function;

c) response time;

d) distance from control source;

e) possible need for secondary control systems for emergency isolation valves;

f) material compatibility of hydraulic/electrical connectors and couplings.

Actuators should be designed such that they can be replaced without affecting pipeline system operation. The design of the connection between valve and actuator should allow visual indication of valve position. The design should be such that the actuator cannot be incorrectly fitted. The actuator should have a visual indicator to show whether the valve is in the “fully open” or “fully closed” position.

7.5.5 Pigging

Pipelines should be designed to accommodate internal inspection tools.
The design for pigging should take into account:

a) provision and location of permanent pig traps or connections for temporary pig traps;

b) isolation arrangements for pig launching and receiving;

c) arrangements for venting and draining for both permanent operations and pre-commissioning;

d) pigging direction(s);

e) permissible minimum bend radius;

f) distance between bends and fittings;

g) maximum permissible changes in diameter;

h) tapering arrangements at internal diameter changes;

i) design of branch connections and compatibility of pipe material;

j) internal fittings;

k) internal coatings;

l) pig signallers;

m) range of flow velocities;

n) number and size of guide bars to be fitted in a barred tee.

7.5.6 Pig traps and closures

The design, fabrication and inspection of closures and details such as nozzle reinforcements, saddle supports and other items not classed as standard pipeline sections should conform to PD 5500 or ASME BPVC-VIII-1.

Closures should be designed such that they cannot be opened while the pig trap is pressurized. This should include an interlock arrangement with the main pipeline valves, at the neck of the pig trap.

Pig traps should be oriented to allow adequate space, and facilities should be provided to open the closure and load/unload pigs.

Detailed procedures should be developed for subsea retrievable pig traps to ensure that deployment recovery presents no risk to the pipeline.

7.5.7 Slug catchers

All vessel-type slug catchers, wherever they are located, should be designed in accordance with PD 5500 or ASME BPVC-VIII-1.

Multi-pipe assemblies which form part of a riser system should be designed accordingly with the limiting hoop stress equal to that required for the riser itself.

7.5.8 Other pressure-containing parts

Other pressure-containing parts for which there is no product standard should be designed with reference to PD 5500 or ASME BPVC-VIII-1.

NOTE The design factors in Table 2 may be used for stress-based design of other pressure-containing components in order to give a consistent level of safety with the connecting pipe.

7.6 Protection

7.6.1 Possible causes of damage

The following potential causes of damage should be taken into account when determining which protection methods to use:

a) dropped objects;

b) anchors, anchor chains or cables;

NOTE 1 Heavy anchors can penetrate the seabed to a depth of several metres depending on anchor mass and soils.

c) seabed fishing activity;

NOTE 2 Expansion spools at tees can require protection against snagging.

d) vessel impact;

e) subsea operations;

NOTE 3 Diver and submersible vehicle activity can cause abrasion and give rise to dropped objects;

f) hydrodynamic loading;

g) seabed mobility;

NOTE 4 Seabed scour, liquefaction or mobility can induce spanning or burial, and can undermine supports.

h) marine growth;

i) seismic activity;

j) snagging of control cables and umbilicals.

7.6.2 Protection methods

7.6.2.1 General

Suitable means of protection should be chosen from the following available options:

a) concrete coating (**7.6.2.2**);

b) anti-corrosion coating (**7.6.2.3**);

c) bundle sleeves (**7.6.2.4**);

d) trenching and backfill (**7.6.2.5**);

e) rock or gravel placement (**7.6.2.6**);

f) grout bags and mattresses (**7.6.2.7**);

g) protective structures (**7.6.2.8**);

h) artificial seaweed mats.

NOTE 1 The selection of these features can be influenced by other design factors (e.g. stabilization and scour prevention). Measures that involve enclosing or covering the pipeline are liable to affect the temperature of the contents and the effectiveness of the pipeline cathodic protection.

*NOTE 2 For protection of pipeline crossings, see **6.10.4**.*

NOTE 3 Further guidance on risk assessment of pipeline protection is given in DNV-RP-F107.

7.6.2.2 Concrete coating

Concrete coatings should be in accordance with **8.9.4** and **8.9.5**.

7.6.2.3 Anti-corrosion coating

Where concrete coating is not applied, the anti-corrosion coating should be selected to give impact resistance and abrasion resistance for the anticipated loadings.

*NOTE See also **9.5.5**.*

7.6.2.4 Bundle sleeves

In addition to protecting the pipeline(s) from impact and abrasion, the strength of the bundle sleeve should be taken into account when determining resistance to trawlboard pull over loads.

7.6.2.5 Trenching and backfill

NOTE Sections of subsea pipeline can be protected from mechanical damage by lowering them beneath the seabed. This can be achieved by trenching only or by trenching and backfill.

When determining the required depth of trenching, any possible variations in seabed level due to sediment mobility should be taken into account.

During the trenching operation, pipeline stress should be maintained within acceptable limits (see Table 2).

Where backfilling of the trench is required, reliance should not necessarily be placed on the natural action of seabed soil mobility.

The design of engineering backfill should take account of the uncertainties inherent in its method of placement (see also **7.6.2.6**).

The effects on pipeline expansion should be taken into account.

7.6.2.6 Rock or gravel placement

NOTE 1 The pipeline can be protected from environmental loads by covering it with suitably graded material. This reduces the possibility of impact and abrasion damage, but penetration of the cover is still possible.

The following factors should be taken into account when stone placement is planned:

a) stability of the placed material;

   NOTE 2 Further information on rock armour is given in BS 6349-1-4.

b) sinking of the placed material into the seabed, particularly where the grain size of the material exceeds that of the underlying seabed;

   NOTE 3 It can be necessary to build up the protective gravel/stone cover in progressively graded layers.

c) possible impact damage to pipe from falling stone during placement;

d) dispersion of gravel or stone material during the placement operation;

   NOTE 4 Dispersion can be reduced by the use of a fall pipe system.

e) damage to the coating as a result of rock or gravel placement.

7.6.2.7 Grout bags and mattresses

The design of grout bag and mattress systems should take into account:

a) stability under environmental loading;

b) location of grout filling points for grout bag systems to allow safe and convenient access and operation;

c) shape, size and flexibility of mattresses to enable accurate placement;

d) the effect of vessel motion when placing mattresses;

e) likely scour effects;

f) the possible need to remove mattresses at some future date.

7.6.2.8 Protective structures

NOTE 1 Protection for valve stations and tees can be accomplished by enclosing them in a protective structure. Protective covers can also be provided for pipelines.

Design criteria for protective structures should include the following.

a) **Stability**. The structure should remain stable under hydrodynamic and accidental loads, and avoid transferring such loads to the pipeline system.

b) **Profile**. The structure should present a smooth profile to minimize the risks of snagging loads and of damage to fishing gear.

c) **Clearances**. In determining clearances between the pipeline system and the structure, account should be taken of:

   1) settlement of the structure foundations;

   2) pipeline expansion movements;

   3) accidental loads;

   4) access for maintenance and repair.

d) **Allowable stresses**. Stresses in the protective structure should be analysed for installation load conditions (including submerged, in air and passing through the splash zone) and in-place load conditions.

   NOTE 2 Analyses are given in BS EN 1992-1-1 for concrete. API RP 2A WSD may also be used for design of steel structures.

e) **Access**. Provision should be made for safe access to the structure for inspection and maintenance. Account should be taken of the risk of detachable access panels being dropped or becoming jammed.

f) **Cathodic protection**. The design of the cathodic protection for the pipeline should be isolated from that of the structure.

7.6.3 Riser protection

Risers and associated pipework should be protected using one or more of the following methods:

a) locating the riser within the structure and routeing pipework to avoid the possibility of impact from falling objects or from vessels;

b) providing a protective fender to exposed risers;

c) providing external fire/explosion protection;

d) providing protective covers, e.g. casting in concrete, where a riser runs horizontally across a support structure such as a concrete gravity structure base caisson.

7.6.4 Flange protection

Profiled flange protectors should be used to prevent snagging of cables.

7.7 Pipeline shutdown systems

NOTE Attention is drawn to the Pipeline Safety Regulations 1996 [18] in respect of emergency shutdown valves (ESDVs) and subsea isolation valves (SSIVs).

Where an ESDV or an SSIV is required, account should be taken of the most appropriate position of the valve.

SSIVs should be installed where they could contribute to the safety of offshore personnel or installations.

8 Design – Materials and coatings

8.1 General

The pressure-containing part of the pipeline should be formed from either low alloy or high alloy steel.

*NOTE Low alloy steels are carbon, carbon manganese and micro-alloyed steels with a ferritic-pearlitic or ferritic-bainitic microstructure. High alloy steels are generally stainless steels with an austenitic, austenitic-ferritic, or supermartensitic microstructure. Further guidance is given in **8.2**.*

Where low alloy steel pipe is to be internally or externally clad, the impact of the cladding process upon the mechanical properties of the pipe and the cladding should be assessed.

When determining whether a pipe material is suitable for a particular application, the following material properties should be taken into account:

a) chemical composition of parent pipe and seam weld (see **8.2.4**);

b) weldability (see **8.2.4**);

c) tensile properties;

d) hardness;

e) fracture toughness and impact resistance (see **8.2.5**);

f) fatigue resistance (see **8.2.6**);

g) corrosion and cracking resistance (see **8.2.7**).

A detailed material specification for each application should be compiled (see also **8.2.2**).

For materials subjected to heat treatment, hot or cold forming, or other processes that can affect the material properties, achievement of mechanical performance in the final condition should be documented. Documentation demonstrating conformity should be provided for:

1) parent metal;

2) weld metal;

3) heat-affected zones;

4) welded pipe, where appropriate.

8.2 Line pipe

8.2.1 General

Carbon and low alloy steel line pipe conveying category A substances should conform to BS EN ISO 3183:2012, PSL 1, API 5L:2012, PSL 1 or BS EN 10224, as appropriate. For pipelines conveying category A fluids associated with oil and gas production (e.g. produced water injection pipelines), line pipe should conform to BS EN ISO 3183:2012, PSL 2 or API 5L:2012, PSL 2.

Line pipe conveying category B, category C, category D or category E substances should conform to BS EN ISO 3183:2012, PSL 2 or API 5L:2012, PSL 2.

PSL 2 pipe for offshore pipelines should conform to the additional requirements specified in BS EN ISO 3183:2012, Annex J or API 5L:2012, Annex J.

Line pipe can be either seamless or welded and a suitable product for the application should be selected.

NOTE 1 Typically, seamless pipe is readily available in diameters up to 610 mm outside diameter in a variety of thicknesses. PSL1 seamless pipe is normally supplied in the hot finished "as rolled" condition. PSL2 pipe is supplied heat treated, either full body normalized (or normalized-rolled) or quenched and tempered (typically for grades L360 and above).

NOTE 2 Welded line pipe up to 508 mm or 610 mm outside diameter, in thicknesses up to 20 mm, is generally produced by the high frequency welding process (HFW). Typically PSL1 HFW pipe is supplied "as welded" whereas PSL2 HFW pipe is generally supplied either full body heat treated or weld line heat treated (where the strip feedstock is produced by either a thermo-mechanical or normalizing rolling process).

NOTE 3 Welded line pipe in diameters above 406.4 mm outside diameter can also be produced by the submerged arc welding (SAW) process. PSL1 SAW pipe is normally produced from hot-rolled plate and is supplied in the as-welded condition. PSL2 SAW pipe is normally produced from thermo-mechanically rolled plate in the as-welded condition with the weld metal being designed to provide equivalent properties to the pipe body. SAW pipe can also be supplied full body heat treated and can be cold expanded, within certain specified limits, to provide improved dimensional tolerances.

Line pipe conforming to BS EN ISO 3183:2012, Annex H should be used for sour service applications.

High alloy steel and other corrosion resistant alloy pipe should conform to an appropriate standard suitable for the purpose of the application, e.g.:

- API 5LC;
- ASTM A312, for austenitic stainless steels;
- ASTM A790, for duplex (austenitic-ferritic) stainless steels;
- ASTM A312, UNS N08904, ASTM B444, N06625 or ASTM B423, N08825, for Ni alloys.

13% chromium super-martensitic steels may also be used in predominantly CO_2 environments.

Clad pipe should conform to API 5LD and should comprise carbon steel line pipe conforming to BS EN ISO 3183:2012 or API 5L:2012 with a suitable corrosion-resistant alloy (CRA) liner. The design and internal corrosion evaluation should address whether the internal stainless steel or non-ferrous metallic layer needs to be metallurgically bonded (clad) or mechanically bonded (lined) or welded (weld overlay) to the outer carbon steel pipe. The minimum thickness of the internal layer should be established during design depending on the product type.

NOTE 4 Weld overlay CRA is frequently used for fittings such as pipe being used for induction bends.

For polymer-lined pipe, the polymeric lining material should be selected to take into account the required mechanical strength of the lining and the corrosion resistance and collapse resistance of the lining material under operational conditions.

8.2.2 Dimensions

The following pipe dimensions should be specified:

a) diameter, quoting either outside diameter or inside diameter;

b) nominal wall thickness;

c) tolerances on diameter and wall thickness;

d) maximum permitted ovality.

The tolerances of clad pipeline systems should be specified to ensure good pipe weld alignment and adequate cladding thickness over the clad surface and at the welded joints.

Line pipe dimensions should be in accordance with the relevant material standard (see **8.2.1**) and the detailed material specification (see **8.1**).

8.2.3 Manufacturing specification

The pipe manufacturer should produce a manufacturing specification, the structure and layout of which should clearly identify and mirror the specified pipe quality standard, including any additional requirements stipulated.

All materials for pipe should be manufactured and used in accordance with the appropriate product standard material specification and this part of PD 8010.

Recommendations in this part of PD 8010 that are not included in the relevant product standard should be specified in the manufacturing specification.

8.2.4 Chemical composition and weldability

The composition of the pipe should be such that weldability is adequate for all stages of manufacture, fabrication and installation of the pipeline. Welding consumables should be selected that avoid the formation of anodic weld metal, which can result in the selective corrosion of weld metal in corrosive environments. Where appropriate, weldability testing of girth welds should be specified at the procurement stage (see BS EN ISO 3183:2012).

The susceptibility of carbon and alloy steel material to hydrogen (cold) cracking due to hardness in the HAZ should be controlled by restricting the allowable value of carbon equivalent (CE).

For traditional carbon manganese steel (C >0.12%), the CE formula shown in equation (10) should generally be used, although for pipelines designed to convey category A substances, where the full chemical formula is typically not reported, the alternative CE formula shown in equation (11) may be used instead.

NOTE 1 All elements in equations (10), (11) and (12) are percentage (%) values.

$$\mathrm{CE} = \mathrm{C} + \frac{\mathrm{Mn}}{6} + \frac{\mathrm{Cr} + \mathrm{Mo} + \mathrm{V}}{5} + \frac{\mathrm{Ni} + \mathrm{Cu}}{15} \qquad (10)$$

$$\mathrm{CE} = \mathrm{C} + \frac{\mathrm{Mn}}{6} + 0.03 \qquad (11)$$

For low carbon content (<0.12%) micro-alloyed steel, carbon content equal to or less than 0.12%, the P_{cm} (cracking carbon equivalent) formula shown in equation (12) should be used.

$$P_{cm} = \mathrm{C} + \frac{\mathrm{Si}}{30} + \frac{\mathrm{Mn} + \mathrm{Cu} + \mathrm{Cr}}{20} + \frac{\mathrm{Ni}}{60} + \frac{\mathrm{Mo}}{15} + \frac{\mathrm{V}}{10} + 5\mathrm{B} \qquad (12)$$

NOTE 2 Guidance on the maximum values for CE and P_{cm} for non-sour and sour service applications is given in BS EN ISO 3183:2012.

For duplex stainless steel, welding consumables should be chosen to match the ferrite/austenite phase balance of the parent material (usually around 50:50). The phase balance in the HAZ tends towards higher ferrite levels. The maximum HAZ ferrite level should be specified, based on the results of weld testing in environments representing the worst anticipated corrosion conditions.

Supermartensitic stainless steels should undergo fitness-for-service testing in the as-welded or post-weld heat-treated condition to demonstrate their suitability for service in the anticipated corrosion conditions under both operating and shut-in conditions.

NOTE 3 Appropriate test methods are described in EFC 17 [32].

In the case of ferritic/austenitic (duplex) stainless steels, the phase ratio should be controlled so as to ensure compatibility between the base material and welding consumables. Tests should be carried out to demonstrate that the corrosion resistance of the HAZ and weld metal matches the parent material and is adequate for service. The weld procedure(s) should ensure that there are no detrimental intermetallic phases formed (e.g. sigma phase) which could impair the mechanical properties or the corrosion resistance.

NOTE 4 This might require supplementary testing to establish that the properties have not been degraded.

NOTE 5 NACE MR0175 and BS EN ISO 15156 give recommendations for materials for use in a sour service environment to prevent sulfide stress corrosion cracking (SSCC).

NOTE 6 NACE TM0284 gives recommendations for testing of materials for use in sour service environments.

8.2.5 Fracture toughness

Parent metal of line pipe for pipelines conveying category C, category D or category E substances should have adequate resistance to brittle and ductile fracture and, where feasible, be capable of arresting running shear fractures. Line pipe should meet the drop weight tear test and Charpy V-notch requirements specified in BS EN ISO 3183:2012. Line pipe for use in pipelines conveying category C, category D or category E substances should also meet the Charpy V-notch requirements given in BS EN ISO 3183:2012, Annex G. Testing should be conducted over a range of temperatures to determine the brittle to ductile transition curve. Charpy V-notch impact testing should be carried out in accordance with BS EN ISO 148-1. A 2 mm radius striker should be used.

The DWTT requirements in BS EN ISO 3183:2012 should be applied to diameters of 323.9 mm and above.

NOTE 1 For high strength steels or pipelines conveying fluids that exhibit two phase behaviour during decompression, the toughness requirements in BS EN ISO 3183:2012, Annex G might not be applicable. It might be necessary to use integral or mechanical crack arrestors to ensure an arrest of a running ductile fracture.

NOTE 2 BS EN ISO 148-1 contains two striker radius options, 2 mm and 8 mm. The 2 mm radius striker is commonly used in Europe, whereas in North America the 8 mm radius is the norm.

In determining the required fracture toughness, the validity of arrest equations should be demonstrated or mechanical crack arrestors should be installed.

In cases where there is no existing full scale fracture propagation test data to confirm crack arrest, or where there has been a change of pipeline parameters or in the fluid being transported, theoretical and experimental studies should be validated using a full scale fracture propagation test to demonstrate crack arrest.

NOTE 3 Full-scale testing has demonstrated that the Battelle Two Curve model for the calculation of fracture arrest toughness does not apply to dense phase CO_2.

8.2.6 Fatigue

Where the mechanical design has identified fatigue loadings, an analysis should be carried out based upon fracture mechanics methods (see BS 7910), or methods utilizing fatigue testing (*S–N* curve) data, to check that the design loading conditions do not exceed the line pipe fatigue resistance within the required design life. Where published *S–N* curves do not exist, fatigue testing of the line pipe should be carried out in accordance with BS 3518-1, BS 3518-3, BS ISO 1143 and BS ISO 12107 as appropriate.

8.2.7 Corrosion and cracking resistance

If CRA selection is the chosen method of internal corrosion control, the pipe material should be resistant to attack from the product and additives over the full range of operating temperatures, pressures and flow rates.

NOTE There are no standard test methods for this; test methods are determined by agreement between the interested parties.

The selection of a corrosion-resistant material should take into account the results of the internal corrosivity evaluations.

8.2.8 High and low temperature service

Where the pipeline is intended to operate below –20 °C or above 50 °C, the required mechanical properties should be clearly defined, documented (unless already specified in the relevant material or product standard) and used in all stages of the design process.

8.2.9 Marking

Marking of line pipe should be in accordance with the requirements of the relevant material or product standard.

8.2.10 Inspection documents

For all pipe materials, an inspection certificate conforming to BS EN 10204, BS ISO 10474 or equivalent should be obtained as a minimum unless otherwise justified by a low potential hazard posed by the pressure and substance to be conveyed.

8.3 Pipeline components

8.3.1 Branch connections

The design and fabrication of welded branch connections and reinforcement, where appropriate, should be in accordance with ASME B31.3 or ASME B31.8. Where welded or forged branch connections are installed in pipelines designed for pigging, special branch connections should be used to ensure that the pig is not damaged whilst passing the connection, and cannot enter the branch or become stuck.

8.3.2 Flanged connections

Flanged connections should meet the requirements of ISO 15590-3 or other internationally recognized standards such as BS ISO 7005-1, ASME B16.5, ASME B16.47 or MSS SP 44.

If proprietary flange designs are used, they should conform as far as is practicable to the relevant sections of PD 5500 or ASME BPVC-VIII-1.

The flange bore should match with the bore of the adjoining pipe wall to facilitate alignment for welding.

External loadings should be taken into account in addition to operational loads. Engineering analysis should be conducted to verify the integrity of the joint.

NOTE 1 The flange standards contain tables giving the bending resistance of standard flanges.

NOTE 2 Finite element analysis can be useful in predicting the load envelopes for proprietary flanges and in reducing conservatisms in standard flanges.

8.3.3 Gaskets

Gaskets should be made of materials that are not likely to be damaged by the fluid in the pipeline system and should be capable of withstanding the pressure and temperature to which they are expected to be subjected in service. The risk of galvanic corrosion should be fully assessed in specifying gasket materials. CRA materials should be used where necessary in areas at risk from crevice corrosion such as ring-type joint grooves and flange facings.

Spiral-wound gaskets should be selected from ASME B16.20 or equivalent with ring material suitable for the product and environment.

Flat-faced and raised-face gaskets should be selected from suitable asbestos-free materials conforming to BS 3293 or ASME B16.21, with the specification and selection of gasket material and profile to suit the substance carried and the machined flange face.

Ring-type joints should be selected from ASME B16.20, API 6A or equivalent. Rings should be of a hardness lower than the flanges.

NOTE Gaskets not featuring reinforced steel brace on internal diameter have been known to crimp and cause obstruction to internal bore of pipelines.

8.3.4 Bolts and nuts

Bolt or studbolt materials should conform to BS 4882, ASTM A193/A193M or ASTM A320/A320M, as appropriate. Nut material should conform to BS 4882 or ASTM A194/A194M, as appropriate.

For non-carbon steel pipelines, bolt materials should be compatible with the pipeline material.

Bolts or studbolts should be full length threaded and should completely extend through the nuts. A detailed assessment of preferred materials for bolting for high alloy flanged connections should be performed.

For sour service duties, bolting should be in accordance with BS EN ISO 15156 or NACE MR0175. For bolted connections where bolt-tensioning devices are to be used, additional bolt length should be provided as applicable.

Where bolting is to be exposed to corrosive conditions or cathodic protection, the material should be selected to take into account the necessary fracture toughness and hardness properties to prevent brittle fracture of high strength bolting.

Where feasible, bolting should be used with hydraulic tensioning equipment to ensure uniformity of loading through the joint.

NOTE The face-to-face dimension of flanged fittings might need to be increased from that stated in the appropriate standard when needed to accommodate specialist bolt tightening equipment.

8.3.5 Bends

8.3.5.1 General

The materials for bends should be similar to those recommended for line pipe (see **8.2.1**). Account should be taken of the properties of the material following the formation of bends, to determine whether any resultant variation from the specified values will be acceptable.

Bends made from straight pipe should be induction bent or mitred. Mitre bends should not be used in pipelines conveying category B, category C, category D or category E substances. They may be used for pipelines conveying category A substances (see ASME B31.3).

Induction bends should meet the requirements of ISO 15590-1, or other internationally recognized standards.

Longitudinal welds should be positioned on the neutral axis of the bend. There should be no wrinkling of the pipe surface.

Because the mechanical properties of a completed bend can differ significantly from those of the straight pipe from which it is made, the bend should be demonstrated to possess mechanical properties compatible with the design of the pipeline system. If necessary, test bends should be produced for destructive testing purposes.

8.3.5.2 Dimensions

Dimensions and tolerances of the ends of the bend cross-section should be compatible with those of the adjoining straight pipe to facilitate joining. If necessary, this may be achieved by the inclusion of straight tangent sections at either or both ends of the bends.

Ovality of cross-section should be restricted such that the bore diameter is reduced by no more than 2.5% of the nominal value at any point along the bend.

NOTE More severe restrictions might be required if inspection devices or well tools are to be used in the line.

The radius of a bend should be chosen to allow for in-line inspection if such inspection is required. The wall thickness of a bend should be not less than the minimum wall thickness of the pipeline.

An allowance should be made for the torus effect and thinning of the parent pipe during bending.

8.3.6 Fittings

The selection of fittings should be based on the same properties as for line pipe (see **8.2.1**). When selecting a fitting, the following should also be taken into account:

a) compatibility with line pipe and weldability;

b) compatibility with product at service temperature;

c) compatibility with product additives at service temperature;

d) compatibility with hydrotest medium and additives;

e) compatibility with seawater, marine growth and marine atmosphere;

f) resistance to abrasion or other mechanical damage likely during installation or service.

In the case of fittings or equipment that contain components made of dissimilar metals, appropriate measures should be taken to prevent or control galvanic corrosion between these metals. Particular attention should be paid to areas where corrosive substances could accumulate or where chemical inhibition might be ineffective.

For materials subjected to heat treatment, hot or cold forming, or other processes that can affect the material properties, achievement of mechanical performance in the final condition should be documented. Documentation should be provided for parent metal and, in the case of welded components, for the weld metal and HAZ.

Fittings should meet the requirements of ISO 15590-2, or other internationally recognized standards such as ASME B16.9.

In-line fittings including connectors, elbows, tees, end caps, reducers and cast or forged transition pieces (e.g. weldolets, sweepolets, nipolets and forged reducers) should be made from fully killed steel. They should be made using recognized practices to provide the intended heat treatment response and notch toughness properties suitable for the duty and fluid category.

8.3.7 Threaded joints

All pipe threads on piping components should be taper pipe threads in accordance with BS 3799 or ASME B16.11. The installation of threaded joints (including compression fittings) should be avoided on buried piping systems. Use of screwed fittings on hydrocarbon systems should be subject to risk assessment. Particular account should be taken of fatigue problems.

8.4 Valves

8.4.1 Valve selection

When selecting valves, account should be taken of factors including, but not limited to:

a) intended duty;

b) system operating pressure and hydrostatic pressure;

c) differential pressure;

d) all fluids to which the valve might be exposed;

e) service temperatures;

NOTE 1 This can include low internal temperatures due to system depressurization.

f) service life;

g) duration of pre-commissioning period;

NOTE 2 Valves can remain static in open or closed positions for long periods but have to be able to function on demand.

h) presence of debris from product or construction activities;

i) system pigging;

j) in situ seal injection or replacement;

k) installation method;

l) ability to test the valve performance;

m) internal galvanic corrosion;

n) reliability;

o) maintenance aspects;

p) actuation;

q) integrity and achievement of isolation.

Ball, check, gate and plug valves should meet the requirements of ISO 14313.

The face-to-face dimension of flanged valves should be increased from that stated in the appropriate standard when necessary to accommodate specialist bolt tightening equipment. In-line valves should allow the passage of inspection devices.

8.4.2 Control of valves

When selecting and designing valve control systems, account should be taken of factors including, but not limited to:

a) type of actuator;

b) valve function;

c) response time;

d) distance from control source;

e) loss of control source and possible need for secondary control systems for emergency isolation valve;

f) power source;

g) material compatibility of hydraulic/electrical connectors and couplings.

8.5 Pig traps and closures

The design, fabrication and inspection of closures, including those designed for repeated opening and closing and details such as nozzle reinforcements, saddle supports and other items not classed as standard pipeline sections, should conform to PD 5500 or ASME BPVC-VIII-1.

Pig traps should be oriented to allow adequate space, and facilities should be provided to open the closure and load/unload pigs. Where possible, the layout and alignment of pig traps should be such that other facilities are not sited immediately behind pig trap doors.

End closures for components including pig traps, filters and prover loops should incorporate an interlocked vent to prevent the closure being opened before the release of pressure from the component. The design should ensure that the hinges and locking mechanism are sufficiently robust to withstand repeated use.

Flat, ellipsoidal, spherical and conical closure heads should be designed in accordance with PD 5500 or ASME BPVC-VIII-1.

8.6 Isolation joints

Electrical isolation joints should be designed in accordance with PD 5500 or ASME BPVC-VIII-1.

The design should take account of vibration, fatigue, cyclic conditions, low temperature, thermal expansion, mechanical abrasion, corrosion, long-term solar or ultraviolet degradation, and construction installation stresses.

Isolation joints should be designed to facilitate travel of internal inspection devices where appropriate.

Before installation into the pipeline the joint should:

a) pass a hydrostatic pressure test without end restraint in accordance with Clause **11**;

b) be tested electrically to confirm the electrical discontinuity.

8.7 Transitions

Nozzle and pipe transitions should be designed to facilitate travel of internal inspection devices where appropriate.

8.8 Other pressure-containing parts

Other pressure-containing parts for which there is no product standard or material standard, e.g. sphere tees, surge and slug catchers, and filters, should be designed in accordance with PD 5500 or ASME BPVC-VIII-1.

8.9 Coatings

*NOTE General recommendations for corrosion coatings and internal coating systems are given in Clause **9**.*

8.9.1 General

The properties needed for a coating can vary along the pipeline and several types of coating could be required. When selecting each coating system, either for internal or external application, the following factors should be taken into account:

a) resistance to moisture penetration;

b) electrical resistivity;

c) ease of application and repair;

d) integrity of coating;

e) adhesion;

f) resistance to impact/damage;

g) resistance to weathering;

h) compatibility with weight coating;

i) flexibility;

j) toxicity to marine life;

k) resistance to cathodic disbondment;

l) suitability at operating temperatures;

m) resistance to biofouling;

n) resistance to ultraviolet light;

o) thermal insulating properties;

p) resistance to slippage.

The coating materials, the coating applicator and the applicator’s procedures should be pre-qualified if they are not covered by a British Standard or acceptable equivalent European, international or other recognized national standard.

8.9.2 Design considerations

Coatings should be designed to resist installation loads and in-service loads. The following types of loads should be taken into account:

a) pipe lay tensioner, roller and lay span loads;

b) pipe tow abrasive loads;

c) pipe trenching loads;

d) fishing activity impact and pull over loads;

e) handling and transportation loads.

The most severe loading which the pipeline is liable to encounter during its lifetime should be taken into account. The design should allow for the transmission of shear loads to prevent coating slip in lay tensioners.

NOTE Concrete does not adhere well to some other coatings, especially fused epoxy powders (otherwise known as fusion-bonded epoxy). Relative movement between the concrete and the corrosion coating may be limited by the application of bands of an aggregate-filled liquid epoxy top coat or a spiral of additional fusion-bonded epoxy coating, before application of the concrete.

For pipelines that are not protected by other means, coatings should be used that are known to resist damage by fishing activities.

8.9.3 Integrity of coating

Concrete should be in accordance with the recommendations given in BS 6349-1-4.

Coating with a 28-day core strength of not less than 3.5×10^7 N/m^2 should be provided (see BS 1881).

NOTE 1 Much higher strengths can be obtained by using application processes capable of working with very low ratios of water to cement of 0.35 and less.

The thickness of the coating should take into account the working limits of the available application processes. Thicknesses less than 45 mm should be evaluated to ensure their suitability for application and endurance under loading.

Strength tests should be carried out on cores cut from coated pipe (see BS EN 12504-1). These tests should be supplemented with strength tests carried out on 100 mm cubes made from concrete taken from the batching plant (see BS EN 12390-3) during concrete application.

NOTE 2 Coating densities less than 2 240 kg/m^3 can require aggregates which reduce the strength of the coating.

Steel reinforcement should be provided to limit spalling and to control cracking (see **8.9.4.4**).

The anti-corrosion coatings can be damaged by concrete coating application. The concrete coating application process should take into account the thickness and type of material being coated and should ensure that coating penetration or unacceptable damage to the anti-corrosion coating does not result.

Water absorption prior to and during production of the weight coating should not exceed a mass fraction of 5%. Testing of dried cured concrete core samples should be in accordance with BS 1881.

8.9.4 Weight coating materials

8.9.4.1 Cement

Cement should be in accordance with BS 6349-1-4 and BS EN 197-1. Sulfate-resisting cement should not normally be used for reinforced concrete in contact with sea water unless chloride limits for the concrete constituents are properly specified and enforced (see BS 6349-1-4).

8.9.4.2 Sand and aggregates

Sand and aggregates should be selected to suit the application method and specified coating properties and should be graded in accordance with BS EN 12620. Limits should be specified on the maximum particle size and the amount of fines smaller than 150 μm.

Aggregates producing a coating density less than 2 240 kg/m^3 should be used with care to ensure that the application process does not damage them.

8.9.4.3 Water

The water used in concrete should be of potable quality (see BS EN 1008).

8.9.4.4 Reinforcement

Reinforcement should be provided by steel bars embedded in the concrete, either in the form of rigid preformed welded cages or as helically wrapped welded mesh. Reinforcement wire and mesh should conform to BS 4482 and BS 4483.

The size and distribution of steel wire reinforcements should be in accordance with Table 3.

Table 3 **Welded reinforcement**

Reinforcement type	Direction of reinforcement	Typical bar diameter mm	Bar spacing mm	Percentage of costing sectional area %
Welded cages	Longitudinal	3 to 8	75 to 400	0.1 to 0.2
	Circumferential	5 to 12	75 to 150	0.45 to 1.0
Wire mesh	Longitudinal	2 to 4	50 to 300	≥0.08
	Circumferential	2 to 4	65 to 100	≥0.4

NOTE Alternative reinforcement materials such as glass fibre may be used if they provide equivalent performance.

Wrapped-in welded wire mesh should be galvanized in accordance with BS EN ISO 1461 or BS EN 10244-2.

Concrete cover should be not less than 15 mm and the clearance between reinforcement and anti-corrosion coating should be not less than 15 mm.

The need for double-layer reinforcement should be assessed if the concrete thickness is greater than 80 mm.

The reinforcement should be electrically isolated from the pipe and rigidly held concentric with the pipe. Cage reinforcement should be positioned by the use of electrically insulating spacers. Spacers should not damage the anti-corrosion coating.

8.9.5 Weight coating application

8.9.5.1 Temperature

Coating should not be applied if:

a) the concrete mix temperature is less than 3 °C, or the pipe temperature is less than 3 °C;

b) ice is present on any of the surfaces or in the constituents;

NOTE Steam heating of aggregates is permissible.

c) the temperature of the pipe, its coating, the reinforcement or the concrete mix exceeds 35 °C.

8.9.5.2 Reinforcement

Steel reinforcement cages should be supported on electrically insulating spacers prior to impingement coating.

When application is made by wrapping, the reinforcement should be tensioned and wrapped with the concrete and supportive outer membrane. Successive wraps of reinforcement should overlap by a minimum of 25 mm.

8.9.5.3 Curing

Unless steam or water spray is used, curing membranes should be applied with the coating or immediately after coating. The curing membrane should be a plastic wrap conforming to ASTM C171 or a spray-applied coating of equivalent performance.

The ambient temperature for pipe storage should not be allowed to fall below 2 °C until the concrete has a minimum strength of 10^7 N/m^2. It should not be allowed to rise to a level which might affect the integrity of the corrosion protection coating.

8.9.5.4 Anodes

Electrical and mechanical attachment of the anode to pipe joint should be made and tested prior to concrete coating.

The anode, including its mechanical and electrical attachments, should be contained within the profile of the concrete coating. The bracelet anode dimensions should, where practicable, be such that the diameter matches that of the concrete coated pipe. Where this is impracticable, the anode outer surface should be tapered to prevent a step at the anode to concrete transition. All gaps between the anode ends and the concrete and between the anode half shells should be filled with a non-conductive mastic or other inert filler material.

Any steel reinforcement in the weight coating should not be in contact with the anodes. Anodes should also be electrically isolated from concrete containing metallic ore aggregates.

8.9.5.5 Tolerances

Tolerances on the submerged weight of each pipe are of primary importance. The tolerance should take into account the possible variations resulting from pipe mill tolerance, corrosion protection coating thickness tolerances, and water absorption.

Submerged weights should be obtained from the calculated displacement of seawater and the measured in-air mass of each pipe.

The submerged weight tolerance should typically be as follows:

a) allowable range for any pipe: $^{+20}_{-10}$%;

b) range per 25 pipes produced: $^{+6}_{-2}$% on a rolling 25 pipe average;

c) range for the daily coating plant production: $^{+4}_{0}$%.

8.9.6 Storage and handling

After coating, pipes should be stored with a minimum amount of handling until the coating is set and fully hardened. Coated and uncoated pipe should at all times be stored out of contact with the ground. Coated pipe, however, should not be placed on skids or racks until the coating has hardened sufficiently to prevent flattening.

Pipes should only be stacked to a height that does not cause flattening of the coating. Concrete coated pipes should not be stacked until the coating has achieved a minimum compressive strength of 1.4×10^7 N/m^2.

8.9.7 Damage

8.9.7.1 Assessment of defects (at coating yard)

Concrete coating should be inspected for defects. Localized repairs are permissible if less than 20% of the coated area is damaged; otherwise total recoating should be carried out.

NOTE Hairline circumferential cracking is not considered to be a coating defect.

8.9.7.2 Repair techniques

Repairs to the coating should be made with materials of equivalent strength and mass to that of the coating.

NOTE Either hand trowelling or guniting are acceptable.

8.10 Insulating materials

Insulating materials are used to maintain operating temperatures in pipelines, and their properties should be taken into account when calculating the submerged mass.

NOTE 1 The following insulating materials may be used:

a) polychloroprene;

b) polychloroethylene;

c) gels (in bundle applications);

d) closed cell polyvinylchloride;

e) syntactic foams based on polyurethane or polypropylene;

f) closed cell polyethylene foam;

g) closed cell polyurethane foam (in pipe-in-pipe systems);

h) mineral wool (in pipe-in-pipe systems);

i) inert low-pressure gas and vacuums (in pipe-in-pipe systems);

j) backfill including rock or sand;

k) nano-gels.

This list is not exclusive, and other insulating materials may be used if they can be shown to lead to the same results.

NOTE 2 Pipeline bundles contained in carrier pipes may be insulated with gels or other insulating materials. Pipe-in-pipe systems may be insulated with foam-based systems, inorganic fillers, half shells or mineral wool.

The load transfer capabilities of the insulating medium should be taken into account where this is necessary to verify overall system structural design performance and response.

All materials should have an established capability for the intended duty, including the ability to withstand the hydrostatic load for the design life.

A suitable outer coating or sheathing should be applied to protect the insulation coating, particularly where concrete coating is to be applied.

9 Design – Corrosion management

9.1 General

Internal and external corrosion of pipeline systems should be managed to minimize the risk of pipeline failure or loss of operability from corrosion within the intended design life of the pipeline. Corrosion management should include:

a) identification and evaluation of potential sources of corrosion (see **9.2** and **9.4**);

b) selection of the pipeline materials;

c) identification of the necessary corrosion mitigation (see **9.3** and **9.5**);

d) definition of the requirements for corrosion monitoring and inspection (see **9.6**);

e) review of the findings from corrosion monitoring and inspection;

f) periodic modification of the requirements of corrosion management, as dictated by experience and changes in the design conditions and environment of the pipeline;

g) maintenance of corrosion mitigation equipment, e.g. chemical injection pumps, corrosion monitoring devices and all cathodic protection equipment.

Internal and external corrosion evaluations should be carried out to determine whether, for the selected material(s), corrosion can be controlled within the design intent over the design life of the pipeline.

The evaluations should be based on relevant operating and maintenance experience, corrosion monitoring, inspection and/or the results of laboratory testing.

Any corrosion allowance should take into account the type and rate of corrosion predicted for the design life of the pipeline.

Possible internal and external corrosion of pipeline materials during transport, storage, construction, testing, preservation, commissioning and operational upset conditions should be included in the evaluations.

*NOTE Examples of the issues that need to be taken into account when selecting a coating system are given in **8.9**.*

9.2 Internal corrosion evaluation

9.2.1 Corrosion mechanisms

A product being transported is deemed to be potentially corrosive if it contains any of the following:

a) free water;

b) oxygen;

c) hydrogen sulfide;

d) carbon dioxide;

e) acids;

f) bacteria;

g) chlorides.

If more than one of these agents is expected, their possible interaction with the pipe should be investigated. The evaluation of corrosivity should take into account all products or combinations of products that are expected to flow through the pipeline throughout its design life.

In systems containing multi-phase mixtures of water and liquid hydrocarbons, the degree of corrosivity is influenced by whether the pipe walls are water-wet or oil-wet. This should be determined by modelling the flow regime for the predicted fluid composition and flow rate at the operating temperature and pressure. Internal corrosion of the pipeline and valves can occur due to the accumulation of water at low points. Pipelines should be de-watered and/or dried (depending on service) and might require regular pigging in service to ensure removal of further accumulations if water is present in the flow stream.

NOTE As long as the water used is treated (e.g. oxygen scavenger, biocide, corrosion inhibitor) it might not be necessary to dry the line depending on the service (oil lines are unlikely to require drying whereas gas lines probably will for hydrate control).

9.2.2 Aqueous corrosion

*COMMENTARY ON **9.2.2***

Aqueous corrosion of carbon and micro-alloyed steels is likely to occur if they are in contact with water containing an acid or a cathodic reactant such as oxygen.

*Both uniform and pitting corrosion are possible. Certain stainless steels and nickel-based alloys are resistant to aqueous corrosion but only in the absence of chloride ions (see **9.2.5**).*

The possibility of aqueous corrosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.3 Corrosion by carbon dioxide

*COMMENTARY ON **9.2.3***

Corrosion of carbon and micro-alloyed steels is likely to occur if carbon dioxide and water are present.

Both general and localized corrosion will occur, the rate depending on temperature, partial pressure of carbon dioxide, flow characteristics and the presence of other corrodents and inhibitors. Certain stainless steels are more resistant to carbon dioxide corrosion than carbon and micro-alloyed steels.

The possibility of carbon dioxide corrosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.4 Corrosion by hydrogen sulfide

If hydrogen sulfide (H_2S) and free water are present in a pipeline, the following types of corrosion are possible and should be taken into account in the design.

a) Micro-alloyed steels are subject to uniform or pitting corrosion.

b) Certain materials are susceptible to sulfide stress cracking (SSC) if exposed to fluids containing H_2S. The risk of SSC depends upon the composition and metallurgical condition of the pipeline material, the concentration of H_2S in the transported fluids and the fluid pressure.

NOTE 1 NACE MR0175 and BS EN ISO 15156 define the limits on pressure and H_2S concentration above which SSC can occur. They also give guidelines on materials selection where a potential for SSC or "sour service" conditions exists.

c) Hydrogen-induced cracking (HIC) can occur in carbon and micro-alloyed steels. The susceptibility of materials to HIC is determined by their microstructure, inclusion morphology and chemical composition.
The resistance of a steel to HIC can be improved by a range of techniques which includes, but is not limited to, reducing the sulfur content, reducing the manganese content, the addition of calcium or rare earth metals to the melt, and selection of an appropriate heat treatment regime.

NOTE 2 NACE TM0177, NACE TM0284 and DNV-OS-F101 give guidance on testing for HIC resistance.

9.2.5 Corrosion in the presence of chlorides

*COMMENTARY ON **9.2.5***

The following forms of attack are likely in the presence of chloride ions in water:

a) accelerated aqueous corrosion of carbon and micro-alloyed steels;

b) crevice corrosion and pitting of stainless steels, especially at elevated temperatures;

c) stress corrosion cracking of austenitic stainless steels under tensile stress at temperatures above approximately 60 °C.

The possibility of chloride corrosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.6 Microbial corrosion

*COMMENTARY ON **9.2.6***

The presence of bacteria or other micro-organisms in a pipeline containing water is likely to give rise to the following corrosive attacks on all types of steels:

a) corrosion through the formation of deposits under which selective dissolution of steels can occur;

*b) corrosive attack by H_2S released by certain species (see **9.2.4**).*

The possibility of microbial corrosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.7 Erosion

*COMMENTARY ON **9.2.7***

Pipe materials can be susceptible to erosion, either by suspended solids or by impinging liquids. Guidance on calculating permissible velocities in pipelines is given in API RP 14E.

DNV-RP-O501 gives guidance on erosion.

The possibility of pipeline erosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.8 Erosion corrosion

*COMMENTARY ON **9.2.8***

Erosion corrosion of the pipe wall can occur if either corrosion protection products or protective coating are removed by impinging liquid or solids.

The possibility of erosion corrosion should be taken into account in the design, with mitigating measures taken where necessary.

9.2.9 Scale formation

Accelerated corrosion can occur under scale. In the event that scale is liable to form, the need for the use of a scale inhibitor [see **9.3.8.2**e)] or descaling agents should assessed.

9.2.10 Combinations of corrosive agents

Where there is no track record of material performance under the specific operating conditions, trials should be carried out to determine the suitability of the proposed material.

9.3 Internal corrosion mitigation

9.3.1 General

The design of a system to control internal corrosion should take into account:

a) pipeline system and lining materials;

b) design life;

c) product composition throughout design life;

d) operating temperature range;

e) operating pressure range;

f) flow characteristics;

g) the need for and frequency of pigging.

9.3.2 Available techniques

Suitable means of controlling internal corrosion should be chosen from the following available options:

a) increased corrosion allowance (see **9.3.4**);

b) corrosion-resistant pipe and welding materials (see **9.3.5**);

c) internal cladding or lining (with corrosion-resistant alloys) (see **9.3.6**);

d) internal lining (with non-metallic coating) (see **9.3.7**);

NOTE Pipe is denoted "clad" if the bond between base and cladding material is metallurgical, and "lined" if the bond is mechanical.

e) product composition control;

f) chemical inhibition;

g) the frequent running of cleaning pigs to remove water and debris accumulation (see **9.2.1**);

h) control of operating parameters, e.g. temperature.

9.3.3 Selection of techniques

The choice of techniques employed for internal corrosion control should be determined by:

a) effectiveness in protection or control of the corrosion mechanisms;

b) reliability of operation over the life of the pipeline;

c) accessibility of the pipeline (for monitoring purposes);

d) ability to monitor internal corrosion;

e) ability of pipeline to pass internal inspection devices.

9.3.4 Corrosion allowance

If corrosion control measures are predicted to be unable to control the integrity of the pipeline over its design life, a corrosion allowance should be provided.

If a corrosion monitoring programme (e.g. product stream analysis, corrosion probes/coupons) indicates that the actual corrosion rate is less than that predicted in design and specification of the corrosion allowance, it might not be necessary to confirm actual wall thicknesses of the pipeline during operation. Otherwise, where a corrosion allowance is used to combat predicted corrosion, a means of demonstrating that the required wall thickness remains should always be provided.

NOTE The provision of a wall thickness greater than that recommended for construction or operational reasons provides some safeguard in the event of unexpected corrosion or other damage occurring.

9.3.5 Corrosion-resistant pipe and welding materials

If the corrosion evaluation indicates that operational mitigation methods are not feasible or not economic, then an assessment of the need for the use of CRA materials should be performed.

9.3.6 Internal cladding

9.3.6.1 Cladding principles

NOTE Cladding can be used as a supplementary means of corrosion protection for areas where corrosion inhibition is likely to be ineffective or where concentrations of corrosive agents are likely to occur, e.g. in areas of high turbulence or in stagnant areas.

Welds, valves and other fittings should be at least as corrosion-resistant as the main pipe. Cladding thickness should be sufficient to ensure:

a) corrosion resistance that is likely to withstand all predictable corrosion upset conditions over the design life;

b) a continuous corrosion-resistant layer after welding.

9.3.6.2 Cladding methods

Plate clad with nickel alloy should conform to ASTM A265. Plate clad with stainless chromium-nickel steel should conform to ASTM A264. The production route should be qualified to ensure that the mechanical properties of the parent metal and the corrosion resistance of the cladding alloy are retained after processing. Testing should include intergranular corrosion and pitting corrosion testing, using methods such as those contained in ASTM A262 (for austenitic stainless steels).

Cladding by weld overlay should be qualified in accordance with ASME BPVC-IX.

9.3.6.3 Joining of clad components

Welding of clad components should be carried out in accordance with qualified procedures. Welds should also be tested for intergranular corrosion and pitting corrosion resistance by the same method as is applicable to the parent cladding material.

9.3.7 Internal lining

Selection of internal lining materials should be based on the following factors:

a) product corrosivity and compatibility with lining;

b) pipeline design life;

c) pigging programme;

d) wear rate;

e) integrity;

f) resistance to blistering under gas decompression;

g) pipeline construction method;

h) available lining application methods (including at field joints);

i) inspection and repair.

NOTE 1 Examples of internal lining materials include:

- *cement mortar linings;*
- *baked and cold-cured thermosetting resins, e.g. epoxy or polyurethane;*
- *thermoplastics, e.g. polyethylene;*
- *elastomers, e.g. nitrile rubber or polyurethane.*

Lining materials, applicators and application procedures should always be pre-qualified.

NOTE 2 In the absence of reliable methods for the measurement of lining integrity during service, it is not recommended that an internal lining be used as the sole means of protection against internal corrosion unless a successful track record is documented for the fluid and flow characteristics expected.

If cement mortar linings are used, centrifugal application methods should conform to BS EN 10311 or AWWA C205 and AWWA C602.

Stoved or cold-cured resins should be applied and inspected as specified in BS 6374-3 and BS 6374-4.

For mill-applied lining, particular care should be taken in selecting the method of coating for the field joints, taking into account the compatibility of the field joint coating with that applied at the factory.

NOTE 3 Because of turbulence at bends, internal lining quality or thickness might need to be higher than for pipe.

9.3.8 Corrosion inhibitors

9.3.8.1 Selection of inhibitors

If inhibitors are to be used in the control of internal corrosion, the following factors should be taken into account:

a) compatibility with pipeline materials, particularly non-metallic materials and valve internal components;

b) product and flow conditions, including the composition of any aqueous phase;

c) inhibitor efficiency in reducing corrosion;

d) solubility and dispersibility of inhibitor;

e) temperature stability of inhibitor;

f) working life of inhibitor;

g) environmental effects, if waste is to be discharged at sea;

h) compatibility with other additives;

i) foaming and emulsifying effects (which could be detrimental to downstream separation);

j) inhibition of upstream facilities, e.g. possibility of carryover of downhole inhibitors;

k) monitoring of effectiveness over the whole pipeline length;

l) application method for optimum effectiveness, e.g. continuous or batch treatment.

9.3.8.2 Types of inhibitor

A number of different types of inhibitor are available. If inhibitors are to be used, the following factors should be taken into account when deciding which one to select.

a) **Film-forming inhibitors**. A relatively high concentration of inhibitor is likely to be required initially in order to build up a protective film on the steel surface, after which smaller quantities might be required to maintain the film. Film-forming inhibitors are ineffective against erosion and in areas of high velocity and turbulence. Stable films of inorganic salts may be used to inhibit corrosion in aqueous lines.

b) **Neutralizing inhibitors**. These inhibit corrosion by altering the pH, thereby reducing corrosion by carbonic and other acids. Their compatibility with other inhibitors should be taken into account.

c) **Biocides**. These can be used to control growth of bacteria and other micro-organisms. Some biocides also alter the pH and can therefore require a neutralizing inhibitor. Environmental issues should be taken into account if biocides are proposed.

d) **Scavengers**. These react with corrosive constituents of the process stream, such as hydrogen sulfide, oxygen and residual water.

e) **Scale inhibitors**. These can be used to prevent scale build-up in aqueous lines. Adjustment of the pH of the fluid might be required for optimal performance.

It can be necessary to introduce several inhibitors, either sequentially or as a mixture. The compatibility of the inhibitors should be taken into account.

The pipeline operator should work closely with the chemical suppliers to determine the optimum product for the fluids and operating conditions. Where no parallel track records exist, the selection of the most appropriate chemical should be supported by laboratory testing and field trials.

9.4 External corrosion evaluation

9.4.1 General

Environments that should be taken into account when evaluating the possibility of external corrosion include:

a) atmosphere (marine/industrial);

b) sea water (tidal zone/shore approach);

c) other facilities.

Environmental parameters that should be taken into account include:

1) ambient temperatures;

2) resistivity, salinity and oxygen content of the environment;

3) bacterial activity;

4) water flow;

5) degree of burial.

The evaluation of corrosion measures should take into account the probable long-term corrosivity of the environment, rather than be solely confined to the as-installed corrosivity.

9.4.2 Corrosion mechanisms

9.4.2.1 Atmospheric corrosion

*COMMENTARY ON **9.4.2.1***

Atmospheric corrosion of pipes can occur in two instances:

a) before installation (during transport or storage of pipes);

b) in the atmospheric zone of risers.

Dry storage and temporary rust preventatives to control corrosion of pipes during storage should be used where appropriate. Atmospheric corrosion of risers should be controlled by application of a coating.

9.4.2.2 Aqueous corrosion

*COMMENTARY ON **9.4.2.2***

For uncoated pipe, the rate of attack is dependent on:

a) metal surface temperature;

b) salinity of the water;

c) aeration of the water;

d) pipe material;

e) velocity of the water;

f) pH of the water;

g) suspended matter in the water;

h) biofouling properties of the water.

Protection of pipes from aqueous corrosion should be provided through coating, cladding, cathodic protection or the use of sleeves filled with chemically inhibited water or an inert medium.

Particular attention should be paid to the protection of risers in the splash zone.

9.4.2.3 Attack in the presence of chlorides

*COMMENTARY ON **9.4.2.3***

The presence of chloride ions enhances:

a) the rate of attack on carbon and micro-alloyed steels;

b) pitting and crevice corrosion of stainless steels;

c) stress corrosion cracking of stainless steels under stress.

An assessment of the suitability of the proposed methods for application and maintenance of coatings to prevent chloride attack on carbon steels should be performed.

An assessment of need for the use of the following methods to minimize localized attack on stainless steels should be performed:

a) avoidance of crevices in steel surfaces and joints at the pipeline design stage, supplemented by avoidance of crevices during the fabrication stage;

b) selection of resistant materials;

c) cathodic protection;

d) eliminating or minimizing coating holidays;

e) avoidance of contamination with carbon steel (e.g. weld spatter, steel filings).

9.4.2.4 Microbial corrosion

The potential for SSC and general corrosion should be taken into account if sulfate-reducing bacteria (SRB) are present.

NOTE 1 Cracking can be prevented by:

a) selection of resistant materials;

b) limitation on weld and base metal hardness;

c) external coating.

NOTE 2 Other micro-organisms can cause crevice corrosion or corrosion beneath deposits.

9.4.2.5 Marine growth

Marine growth can cause crevice corrosion and can hide or enhance existing corrosion. Anti-fouling coating should be applied or mechanical removal carried out if marine growth is likely. The effect on the environment of anti-fouling systems should be taken into account.

9.4.2.6 Effects of elevated temperature

Account should be taken of the effect of temperature on all corrosion processes. Attention should be paid to additional corrosion mechanisms likely to occur at elevated temperatures which do not occur at lower temperatures. High temperatures affect the choice of corrosion coating and anode material. Account should be taken of the actual surface temperatures experienced at the external surface, including the effect of pipeline burial whether planned or natural.

9.5 External corrosion mitigation

9.5.1 General

The design of a system to control external corrosion should take into account:

a) pipeline system;

b) design life;

c) operating temperature range;

d) pipeline installation method;

e) environmental conditions (including soil properties);

f) presence of bacteria;

g) adjacent structures and cathodic protection;

h) degree of burial, whether planned or due to natural settlement.

A corrosion allowance should be made if any corrosion of the pipeline is anticipated.

9.5.2 Available techniques

A suitable means of controlling external corrosion should be chosen from the following available options:

a) external coating (see **9.5.4**, **9.5.5**, **9.5.6** and **9.5.7**);

b) external cladding (see **9.5.8**);

c) corrosion-resistant pipe;

d) cathodic protection (see **9.5.9**);

e) chemical inhibition of environment (e.g. for a pipeline or risers inside a closed caisson or sleeve pipe).

9.5.3 Selection of techniques

The choice of techniques employed for external corrosion control should be determined by:

a) effectiveness in preventing or controlling the corrosion mechanisms;

b) requirements for installation, inspection and maintenance of the system;

c) reliability of operation over the life of the pipeline and consequences of protection system failure or damage;

d) pipeline installation techniques;

e) application of weight coating.

NOTE The type of corrosion protection employed may vary for different parts of the pipeline.

9.5.4 Non-metallic coatings and linings

9.5.4.1 Coating selection

When selecting coatings the following should be taken into account:

a) environment to which the pipe is likely to be exposed (from fabrication through to end of service life);

b) temperatures to which the pipe is likely to be exposed;

c) available means of application (e.g. site or mill application);

d) exposure to moisture;

e) means and ease of inspection and repair;

f) extent of coating breakdown throughout design life;

g) pipe installation method;

h) durability required for the coating.

9.5.4.2 Surface preparation

NOTE 1 Good surface preparation is essential to satisfactory coating performance. General guidance for all aspects of surface preparation is given in BS EN ISO 8501.

Deposits of oil and grease on the steel surface should be removed by solvent cleaning. Cleaning, including blast cleaning of carbon and micro-alloyed steel, should be carried out in accordance with BS EN ISO 8501.

Supplementary cleaning (in addition to that achieved by blast cleaning, or for small areas of steel) should be carried out using power or hand tools in accordance with BS EN ISO 8501.

Where used as a substitute for blast cleaning, pickling should conform to BS EN ISO 8501. After pickling, all acids and deposits should be rinsed off the pipe before the coating proceeds.

The standard of cleanliness after preparation should be judged in accordance with BS EN ISO 8501.

Surface roughness should be specified with due account taken of the thickness of subsequent coating, and its adhesion to steels. Methods of measuring profile should be in accordance with BS EN ISO 8501.

Non-ferrous abrasives only should be used to prepare stainless steel surfaces. A first quality finish in accordance with BS EN ISO 8501 and a high surface profile should be achieved to ensure good coating adhesion. Surface roughness should be assessed in accordance with BS EN ISO 8503.

The maximum allowable time between preparation and coating should be limited, taking into account humidity and pipe temperature.

All prepared surfaces should be tested in accordance with BS EN ISO 8502 to ascertain levels of soluble salt contamination. Surfaces found to be contaminated should be washed with potable water, dried and re-tested.

NOTE 2 In the presence of chlorides, high profile surfaces can cause crevice corrosion.

9.5.5 External coatings

9.5.5.1 Reinforced bitumen and enamels

Bitumen (asphalt)-based materials and primers should not be used as they have generally been superseded by alternative and environmentally acceptable alternatives.

9.5.5.2 Cold-applied tape wraps and shrink sleeves

The need for the use of cold applied wraps and shrink sleeves should be assessed.

NOTE Cold-applied tape wraps and shrink sleeves may be used for the following applications:

a) field joint coating;

b) added protection of pre-coated pipes;

c) coating of short lengths of pipe or fittings.

9.5.5.3 Polyethylene

Polyethylene coatings should conform to DNV-RP-F106. Acid washing and chromate or phosphate pre-treatment should be used where appropriate. The fusion-bonded epoxy layer thickness should be chosen taking into account the blasted profile. It should typically be not less than 100 μm, and a thicker layer should be used where appropriate.

9.5.5.4 Epoxy and associated systems

Fusion-bonded epoxy coatings used to protect the externals of pipe should conform to DNV-RP-F106. Liquid-applied epoxy coatings used for the protection of bends and fittings should have a proven track record in immersion service and should be resistant to cathodic disbondment.

9.5.5.5 Elastomers

The need for the use of elastomers should be assessed.

NOTE Polychloroprene and related elastomers, such as ethylene propylene diamine monomer (EPD M), provide a coating of high integrity and resistance to mechanical damage when suitably compounded and vulcanized. They are commonly used for protection of risers, particularly in the splash zone.

9.5.5.6 Polypropylene

NOTE Three-layer polypropylene coatings are similar to three-layer polyethylene coatings in that a fusion-bonded epoxy coating is applied as a first layer and a second layer of copolymer adhesive. However, they are able to withstand a higher operating temperature than polyethylene.

If polypropylene coating generally and three-layer polypropylene coating in particular are used, they should conform to the requirements in DNV-RP-F106. Acid washing and chromate or phosphate pre-treatment should be used where appropriate. The fusion-bonded epoxy layer thickness should be chosen taking into account the blasted profile. It should typically be not less than 100 μm, and a thicker layer should be used where appropriate.

9.5.5.7 Paint systems

NOTE 1 Parts of risers, J-tubes, spool pieces and piping, whether submerged, in the splash zone or above water, can be protected by painting with solvent-based or chemically cured paint.

Paint systems should be in accordance with BS EN ISO 12944.

NOTE 2 Further guidance is given in BS EN ISO 14713 (all parts).

9.5.5.8 Polymer cement coatings

The need for the use of poly cement coatings should be assessed.

NOTE Polymer cement coatings may be used to provide mechanical protection to thin film anti-corrosion coatings. They generally consist of a polymer-modified cement mortar reinforced with glass fibres.

9.5.5.9 Anti-fouling coating

NOTE 1 Anti-fouling coatings are usually only used to minimize wave loadings on critical areas such as risers in the splash zone. They may be applied over the anti-corrosion coating and may consist of:

a) paint which is toxic to marine life;

b) copper or copper alloy particles embedded in coatings;

c) low surface energy coatings.

The environmental effects of any anti-fouling compound should be taken into account.

NOTE 2 Organotin compounds are banned for marine use.

9.5.6 Field joint coating

9.5.6.1 Coating selection

When selecting a field joint coating system the following should be taken into account:

a) compatibility with the construction method;

b) good adhesion of coating to pipe and existing coating;

c) resistance to heat;

d) resistance to the subsea environment;

e) compatibility with cathodic protection;

f) resistance to installation loads (particularly of infill materials);

g) toxicity to marine life;

h) impact resistance;

i) maintenance of overall diameter;

j) compatibility of coating and infill materials;

k) inspection and repair during application.

NOTE 1 For concrete-coated pipelines, the field jointing system may comprise both an anti-corrosion coat and an infill system.

NOTE 2 Further guidance on field joint coatings is given in DNV-RP-F102.

9.5.6.2 Wraps and sleeves

The need for the use of wraps and sleeves should be assessed.

NOTE Some self-adhesive tapes are suitable for offshore application. Heat-shrinkable sleeves and wraps are also suitable for offshore use.

9.5.6.3 Mastic or foam infill

When using mastic or foam infills, account should be taken of:

a) temperature range for the mastic before pouring or foam before mould-injecting;

b) cooling of the joint before the pipe is laid;

c) effects on primary anti-corrosion coating.

9.5.6.4 Half shell infill

NOTE Pre-formed half shells may be used for field joints to provide either continuous thermal insulation or mechanical protection.

When using half shell infills, account should be taken of:

a) method of application and fastening, risk of snagging by installation equipment, fishing gear, etc.;

b) application of a bonded coat to the steel pipeline surface under the half shells and risk of seawater ingress under half shell;

c) load transfer through half shell.

9.5.7 Metallic coatings and claddings

9.5.7.1 Selection

NOTE Metallic coatings may be used for the protection of components for which other coating systems are unsuited (e.g. those that are more suited to bulk coating of pipe and bends).

When selecting a metallic coating, account should be taken of:

a) corrosivity of the environment;

b) service temperatures;

c) design life.

9.5.7.2 Zinc coatings

NOTE Zinc coatings are most often applied to fasteners or other items ancillary to the pipeline itself.

Zinc should be applied to steel by one of the following methods:

a) galvanizing;

b) electroplating;

c) spraying;

d) painting.

Zinc coatings for steel structures and equipment in a marine environment should conform to the guidelines given in BS EN ISO 14713 (all parts). The plating of threaded components should conform to BS 7371-12.

Zinc does not reduce the need for cathodic protection. If zinc-coated pipeline is employed with cathodic protection, care should be taken with the choice of sacrificial anode material.

9.5.7.3 Nickel plating

Electroplating with nickel should be used to provide an anti-corrosive coating.

NOTE 1 Electroless nickel plating can be used as a corrosion-resistant overlay on valve components but difficulty might be experienced in obtaining a high-integrity coating. The corrosion protection performance of electroless nickel is dependent on the phosphorous content of the coating.

For threaded components, electroplated nickel coatings should conform to BS 7371-12.

NOTE 2 Unlike zinc, nickel is noble to steel, and in the event of coating damage, it is likely to accelerate corrosion of the base metal.

9.5.7.4 Sprayed aluminium

The need for the use of sprayed aluminium should be assessed.

NOTE Thermally sprayed aluminium can provide a sacrificial protection system with a finite life related to its thickness. It can also reduce the requirement for cathodic protection.

9.5.8 External cladding

External cladding is particularly suited to the protection of risers in the splash zone. When selecting cladding, account should be taken of:

a) corrosion resistance in the splash zone;

b) resistance to biofouling;

c) resistance to mechanical damage, e.g. minor impacts;

d) weldability;

e) ease of repair.

NOTE Suitable materials for splash zone protection include:

- *nickel-copper alloys;*
- *cupronickels;*
- *certain copper-containing stainless steels.*

Hydrogen can accumulate under cladding, causing failure.

There should be no leak paths that allow water to penetrate between cladding and substrate. The effect of a clad riser on the cathodic protection of the pipeline and platform should be taken into account.

9.5.9 Cathodic protection

9.5.9.1 General

Defects in external coating systems enable the pipeline steel to come into contact with its surroundings, resulting in pipeline corrosion. Cathodic protection should be installed to mitigate this corrosion. Cathodic protection may be applied by the sacrificial anode or impressed current method.

NOTE The application of impressed current cathodic protection to a pipeline can cause adverse effects on structures close to the protected pipeline.

9.5.9.2 Design

Cathodic protection should be designed in accordance with DNV-RP-F103 or other internationally recognized standard such as BS EN ISO 15589-2, and with the recommendations given in this subclause.

The current density should be appropriate for the pipeline temperature, the selected coating, the environment to which the pipeline is exposed and other external conditions affecting the current demand. Coating degradation, coating damage during construction or caused by third-party activities, and metal exposure over the design life should be predicted and taken into account when determining the design current densities.

When solid CRAs are selected the minimum cathodic protection voltage should be established, depending upon the hydrogen cracking resistance of the pipeline material.

Cathodic protection should normally be provided by sacrificial anodes.

The design of sacrificial anode cathodic protection systems should be documented and should include reference to:

a) pipeline design life;

b) pipeline operating conditions;

c) design criteria and environmental conditions;

d) applicable standards;

e) requirements for electrical isolation;

f) calculations of the pipeline area to be protected;

g) performance of the anode material in the design temperature range;

h) number and design of anodes and their distribution;

i) protection against the effects of possible a.c. and/or d.c. electrical interference.

Zinc should not be used as a sacrificial anode at temperatures above 70 °C; corrosion of steel can be accelerated at this temperature by contact with zinc in certain environments.

9.5.9.3 Connections

Cathodic protection anodes and cables should be joined to the pipeline by connections with a metallurgical bond.

The design of the connections should take into account:

a) the requirements for electrical conductivity;

b) the requirements for adequate mechanical strength and protection against potential damage during construction;

c) changes to the metallurgy of the parent metal due to localized heating during the attachment process. Doubler plates should be used when connecting anodes and cables to pipelines.

Possible interference by extraneous sources in the vicinity of the pipelines and the possible effect of protection of the new pipeline on existing protection systems should be evaluated.

The shielding by thermal insulation and pipeline protection systems (shrouds, covers, etc.) and possible adverse effects of stray currents from other sources should be taken into account when selecting cathodic protection for insulated pipelines.

9.6 Monitoring programmes and methods

9.6.1 General

Corrosion monitoring programmes should be established on the basis of the predicted corrosion mechanisms and corrosion rates (see **9.2** and **9.4**), the selected corrosion mitigation methods (see **9.3** and **9.5**), and safety and environmental factors.

Internal inspection tools should be used where monitoring of internal or external corrosion or other defects is needed over the full length of the pipeline. Approximate rates or trends of corrosion degradation may be determined by analysis of the results of consecutive metal loss inspections.

An internal or external inspection of the pipeline soon after commissioning should be carried out to record and identify the as-installed condition of the pipeline, and to provide a baseline for the interpretation of future surveys.

9.6.2 Monitoring internal corrosion

9.6.2.1 Selection of methods

The selection of methods for monitoring internal corrosion should take into account:

a) anticipated type of corrosion;

b) potential for water separation, erosion, etc. (flow characteristics);

c) anticipated corrosion rate (see **9.2**);

d) required accuracy of metal loss measurement;

e) available internal and external access;

f) hindrance of passage of pigs or inspection devices by internal obstructions.

NOTE 1 Techniques that can be used to assess fluid corrosivity include the installation of mass loss coupons and probes and fluid sampling points. However, as these require ready access by personnel, they can only be located at the extremities of the pipeline and might not be representative of the most corrosive conditions.

NOTE 2 Effective monitoring techniques and applications for pipelines are shown in Table 4.

9.6.2.2 Location of test points for local corrosion monitoring

Subject to availability and practicability of access, test points for corrosion monitoring should be located along the pipeline or associated facilities, where representative indications of corrosion in the pipeline are most likely to be obtained.

Corrosion probes should be fitted flush with the internal wall of the pipe where pigging might occur. Additional probes in areas of high velocity flow should be installed where necessary.

Table 4 **Monitoring methods**

Technique	Application	Notes
Corrosion coupons	All forms of corrosion	Not suitable for SCC or SSC
Electrical resistance probes	Uniform corrosion	Not always suitable for sour service applications
Hydrogen probes	Sour corrosion HIC and SSC	Not suitable for other forms of corrosion
Linear polarization probes	Uniform corrosion	Require continuous electrolyte
Product analysis	General corrosion rates	Will not detect very localized corrosion or environment assisted cracking
Thin layer activation probes	Uniform corrosion and erosion	Double activated layers required to detect localized corrosion
Galvanic probes	Product corrosivity	Suitable to monitor oxygen ingress, etc.
Ultrasonic thickness gauges	Uniform corrosion and erosion	Does not reliably detect localized corrosion
Radiography	Localized	HIC and other forms of cracking might not be detected
Inspection devices	General corrosion and erosion and localized pitting	HIC and other forms of cracking might not be detected

9.6.3 Monitoring external pipeline condition

Accessible pipeline sections should be visually surveyed periodically to assess the conditions of the pipeline, and where applied, its coating. Buried or submerged pipelines should also be inspected when exposed.

Close visual examination of the coating should be carried out periodically at locations with a high probability of severe corrosion.

NOTE Periodic continuous potential surveys of the pipeline using ROVs can be used for this purpose where the area of possibly severe attack cannot be visually examined.

9.6.4 Monitoring cathodic protection

Periodic surveys should be carried out to monitor the level of cathodic protection. The frequency of these surveys should be based on:

a) the method of cathodic protection;

b) the uniformity of soil properties along the pipeline and the degree of burial, either engineered or natural;

c) the coating quality;

d) safety and environmental concerns;

e) possible interference from electrical sources;

f) alteration in pipeline operating conditions (i.e. temperature);

g) results from previous surveys.

Continuous "over the line" cathodic protection surveys using an ROV should be performed when abnormal coating damage, severely corrosive conditions and/or stray current interference are suspected.

NOTE Such surveys provide more detailed information concerning the corrosion protection of the pipeline.

9.6.5 Evaluation of monitoring and inspection results

Permanent records of the corrosion control measures should be maintained. These include:

- internal and external coating;
- cathodic protection monitoring results;
- details and locations of bonding to third-party systems;
- results of surveys.

All findings of the monitoring and inspection activities should be analysed to:

a) review the adequacy of the corrosion management;

b) identify possible improvements;

c) indicate the need for further detailed assessment of the pipeline condition;

d) indicate the need to modify the corrosion management methods.

9.7 Corrosion management documentation

The following aspects of corrosion management should be documented:

a) assessment of the corrosion threats and associated potentials for failure (see **9.1**, **9.2** and **9.4**);

b) choice of materials and corrosion mitigation methods (see **9.1**, **9.3** and **9.5**);

c) selection of inspection and corrosion monitoring techniques and inspection frequencies (see **9.6**);

d) any specific decommissioning and abandonment issues associated with the selected corrosion management approach.

10 Construction – Fabrication and installation

10.1 General

Work should be carried out in such a way as to ensure the safety of the workforce, third parties and the protection of property and the environment.

Competent personnel, capable of assessing the quality of the work within the scope of this part of PD 8010, should be employed for the supervision, inspection and execution of the construction project.

Contractors appointed by the operator should possess the qualifications necessary for the execution of the work.

*NOTE The safety and reliability of a pipeline system can be improved by the application of quality assurance procedures in construction (see **4.3**).*

10.2 Safety plan and procedures

NOTE 1 Attention is drawn to the following legislation in respect of the health, safety and welfare of all employees and members of the public in connection with the design, construction, operation and maintenance of pipelines:

- *Construction (Design and Management) Regulations 2007 [2];*
- *Construction (Lifting Operations) Regulations 1961 [33];*
- *Control of Major Accident Hazard Regulations 1999 [34];*
- *Control of Major Accident Hazards (Amendment) Regulations 2005 [35];*
- *Factories Act 1961 [36];*

- *Factories Act (Northern Ireland) 1965 [37];*
- *Gas Safety (Management) Regulations 1996 [6];*
- *Health and Safety at Work, etc. Act 1974 [7];*
- *Health and Safety at Work (Northern Ireland) Order 1978 [8];*
- *Ionising Radiations Regulations 1999 [38];*
- *Offshore Installations (Safety Case) Regulations 2005 [39];*
- *Pipelines Safety Regulations 1996 [18];*
- *Pressure Systems Safety Regulations 2000 [22];*
- *all regulations enacted under these.*

Attention is also drawn to guidance notes and Approved Codes of Practice published by appropriate authorities.

The safety plan should describe requirements and measures for the protection of:

a) the health and safety of the public;

b) personnel involved in the construction;

c) the environment.

It should contain references to the relevant legislation and applicable standards, identification of hazards and measures needed for their control, and should highlight any emergency procedures needed in the completion of the construction.

High standards of safety should be maintained at all times. Safety training should be given to all employees engaged in supervision and construction of pipelines. Safety procedures and equipment should be provided for normal installation and contingency conditions.

*NOTE 2 See also **10.13**.*

Supervisors should be appointed who are responsible for ensuring that the necessary safety procedures are implemented.

10.3 Construction plan

A construction plan should be prepared by the principal contractor before commencement of construction to assist in the control of the work. This plan should be commensurate with the complexity and the hazards of the work and should contain as a minimum:

a) a description of the construction;

b) a programme of the construction;

c) a quality plan;

d) a health and safety plan;

e) an environmental plan;

f) methods of controlling and handling materials;

g) marine traffic management plans.

The description of the construction should include methods, personnel and equipment needed for the construction and working procedures.

10.4 Construction near other facilities

All facilities that could be affected by construction of a pipeline system should be identified prior to beginning the work.

Temporary provisions and safety measures necessary to protect the identified facilities during construction should be established. Owners and operators of the facilities should be consulted when defining these temporary provisions and safety measures, and should be given timely notification of the commencement of construction.

NOTE Facilities that could be affected include existing platforms, wells, crossings, pipelines and cables.

10.5 Transport and handling of materials

A material control system should be adopted to monitor material throughout, from supplier, transport, lifting and handling, to receipt at site, quality checks, storage and issue.

A risk assessment should be carried out prior to the handling of materials to ensure that the activity is carried out in a safe manner and to avoid damage.

Transport and handling procedures might be needed, which should identify the equipment to be used and the stacking requirements.

NOTE 1 API RP 5L1 and API RP 5LW provide guidance on the transport of line pipe.

Care should be taken to prevent damage to pipes, fittings and coating during handling. Slings or equipment used for handling pipes should be designed to prevent pipe or coating damage. Pipes should be visually inspected for possible damage in transit. Any damaged areas should be inspected for non-conformity to the relevant material specifications. Materials should not be installed until the material certification can be verified and any damage and/or defects have been removed or repaired.

If an electromagnet is used to lift the line pipe, the residual magnetism should be measured. If residual magnetism is found to exist, methods should be adopted to de-magnetize the pipe and enable arc welding to be carried out.

During storage the pipes should be protected against damage and corrosion and, where necessary, should be separated from one another by suitable means (see **9.1**).

NOTE 2 It is essential that these storage facilities are safe and stable at all times.

Materials not conforming to the relevant material specification should be isolated and quarantined from all other materials, until the quality and correctness can be confirmed. If materials fail they should be returned to the manufacturer or supplier for replacement.

10.6 Construction supervision

Competent and experienced staff should be appointed to supervise the full range of pipeline construction activities.

Particular attention should be given to environmental matters, quality assurance and public safety aspects of pipeline construction.

10.7 Working season

Wherever possible, the construction period for pipelines should take into account fishing and spawning cycles, tourist seasons, inclement weather, etc.

10.8 Administration

10.8.1 Communications

Good reliable communications should be established within the working areas, and between the working areas and the construction central base office, to ensure safety, and quick emergency response. Modern communication equipment should be used and the workforce should be trained and competent in the use of this equipment.

10.8.2 Quality of materials and workmanship

A quality control system should be introduced to ensure that construction activities are carried out in accordance with the approved quality plan and design specifications. Items such as welding records, material and test certificates, and coating records should form part of the as-built documentation.

10.9 Environmental issues

Work should be carried out with minimum disturbance to the environment. Care should be taken not to create pollution, e.g. fuel and chemical spillage.

If an environmental management plan is required, it should include details of commitments made from the process of carrying out an environmental impact assessment (EIA).

In order to carry out the construction works efficiently, a traffic management plan should be developed. This plan should be discussed with the marine authorities at the earliest opportunity. The plan should ensure that any disturbance to marine traffic and other users of the sea, e.g. fishing organizations, is minimized.

10.10 Welding and joining

10.10.1 Welding

Welding of pipeline systems should be carried out in accordance with BS 4515-1 and BS 4515-2. Examination of construction welds in pipeline systems should be performed in accordance with BS 4515-1 and BS 4515-2 and, except as allowed for tie-in welds, the weld examination should be carried out before pressure-testing.

Low hydrogen welding consumables should be used for welds in carbon manganese steel because they are less susceptible to delayed hydrogen cracking. Cellulosic coated electrodes should not be used.

All welds should be fully examined by radiography or ultrasonics.

Examination should cover the weld over its full circumference. The examination should be appropriate to the joint configuration, wall thickness and pipe diameter.

Welds should meet the acceptance criteria specified in the appropriate part of BS 4515, API 1104 or DNV-OS-F101. Welds not meeting these criteria should either be removed or, if permitted, repaired and reinspected.

Welder qualification should be in accordance with BS EN ISO 9606-1. Welding procedures should be in accordance with BS EN ISO 15607 and BS EN ISO 15609. Welding consumables should be in accordance with BS EN ISO 15610. Welding procedure qualification should be in accordance with BS EN ISO 15614.

10.10.2 Joining other than welding

Where selecting a non-welded joining method, account should be taken of:

a) pipeline operating conditions;

b) installation methods, stresses and loads;

c) corrosion resistance;

d) joint mechanical properties;

e) joint reliability;

f) joint maintenance requirements;

g) joint inspection and testing techniques during and after construction.

The non-welded joint should provide structural integrity and corrosion resistance equal to or better than the design requirements for the parent pipe.

A connection method should wherever possible have proven reliability under the proposed operating conditions. Proving trials should be performed where this is not the case.

10.11 Marine operations

10.11.1 Vessels

Prior to mobilization to site of construction vessels such as lay vessels, trench vessels and diving support vessels, an inspection or survey should be performed to determine whether the principal equipment is suitable for the intended work.

10.11.2 Anchors and station keeping

10.11.2.1 General

The station keeping system should have redundancy or back-up systems to minimize the possibility of other marine vessels or installations being endangered by its partial failure.

10.11.2.2 Anchor patterns

Any construction vessel using anchors to maintain position should do so in accordance with a predetermined anchor pattern. The anchor pattern should be shown on a bathymetric chart, of appropriate scale, containing the following information:

a) position of each anchor and cable touch down point;

b) location of existing pipelines and installations;

c) vertical clearance between anchor cables and pipelines;

d) proposed pipeline route and lay corridor;

e) temporary works present during the construction period;

f) anchor patterns of other vessels in the vicinity;

g) vessel position for running each anchor;

h) working position(s) of vessel once anchor running is complete;

i) prohibited anchoring zones;

j) wrecks and other potential obstructions;

k) estimated residual anchor mound height.

Care should be taken in correlating different survey data.

Vessels should have a procedure for leaving the work location in an emergency or when anchors cannot be recovered.

10.11.2.3 Anchor and cable clearances

To prevent damage to existing facilities, minimum clearances should be established between anchor and anchor cables and fixed structures, subsea installations or other pipelines. The clearance to be imposed between an anchor, its cable, and a fixed structure, subsea installation or pipeline should take account of:

a) duration at location;

b) prevailing weather direction and seasonal weather;

c) other work locations and emergency stand-off location;

d) type of soil conditions;

e) anchor system and loading;

f) planned movement of vessel both towards and away from a structure;

g) tidal and current variations;

h) additional measures implemented to prevent damage.

10.11.2.4 Anchor handling

All anchors transported over subsea installations or pipelines should be decked onto the anchor-handling vessel and should be secure.

Construction vessel anchor winches should be equipped with a cable footage and load indicator. These should be calibrated during mobilization.

Attention should be paid to anchor running in shallow water when anchor cables might not follow the straight line route between anchored vessel and anchor.

10.12 Vessel positioning

10.12.1 Positioning systems

Horizontal surface positioning should form the basis for locating prime construction vessels, pipeline position and points of reference for local positioning systems.

The system chosen should be able to give a continuous position compatible with the positioning tolerances, availability and redundancy imposed by the choice of the pipeline route and anchor locations.

The system should feature a 100% redundancy or standby to allow for breakdown. It should provide the following information:

a) position relative to the chosen grid reference system;

b) geographical position;

c) visual display and record of planned and actual pipeline route and actual track;

d) visual display and record of other positionally fixed structures;

e) offsets from antenna position.

NOTE During installation within congested areas or during start-up and laydown, a local positioning system of greater accuracy might be necessary, such as acoustic transponder systems. ROVs may be used to monitor the touchdown point.

10.12.2 Calibration

Prior to performing construction activities, the positioning system should be calibrated to ensure that all functions are operating within the prescribed limits of accuracy. The survey system used offshore should be correlated with the onshore survey system when the pipeline system includes a shoreline crossing.

10.13 Installation of pipelines

10.13.1 General

10.13.1.1 Procedures

Procedures should be developed to demonstrate that construction can be performed in a safe and efficient manner.

10.13.1.2 Survey

Prior to installation, a survey should be carried out along the proposed pipeline route corridor (see **E.1**).

10.13.1.3 Material transportation and storage

Care should be taken to prevent damage to pipes, fittings and coatings during handling. Slings or equipment used for handling pipes should be designed to prevent pipe or coating damage.

Storage of pipes should be in pipe racks with protection to minimize damage to pipes and coatings. Maximum stacking heights should be established which do not impose excessive loads on the pipe or its coatings.

All material should be recorded on a manifest and pipe tracking records maintained.

10.13.1.4 Welded fabrication

Prior to welding, each pipe should be checked for mechanical damage both to the pipe steel and to any pipe coating. All pipe alignment and welding should be in accordance with **10.10**. As each joint is welded, the pipe number should be recorded together with the length of the pipe. The laying sequence number should be painted on either side of the pipe in contrasting paint.

10.13.2 S-lay method

10.13.2.1 Pipeline fabrication

Dimensions and tolerances should be in accordance with **8.2.2**. Care should be taken to avoid disruption at the lay vessel work stations through the use of successive short or long lengths of pipe.

10.13.2.2 Field joint coating

Field joint coating should be in accordance with **9.5.6**.

10.13.2.3 Pipeline installation configuration

The pipe should be maintained under controlled tension to ensure that it is lowered onto the seabed within the stress limits given in **6.4.2** or allowable strain given in **6.4.3**.

10.13.2.4 Pipeline support

The pipeline should be supported along the length of the vessel on rollers or tracks that allow the pipe to move axially. The rollers should be faced with a material that is not likely to damage the pipe coating, field joint coatings or anodes.

The height and spacing of the rollers should be adjusted to ensure a smooth transition from the vessel to the stinger, and should be spaced to maintain the loads in the pipeline within the limits given in **6.4.2** and **6.4.3**. Pipeline fittings should be prevented from hooking behind rollers.

10.13.2.5 Stinger

The pipeline supports on the stinger should be similar to those on the lay vessel and should be equipped with load cells. If the stinger is of the buoyant type, the last roller mounted on the vessel should also be equipped with a load cell.

A video camera should be maintained at the end of the stinger to view the pipeline at the last roller.

10.13.2.6 Buckle detection

The need for use of a buckle detector during laying should be assessed, such that reductions in diameter of the pipe of 5% or greater are detected.

The buckle detector should always remain behind the touch down point of the pipe on the seabed. The effects of pipeline tees or fittings on buckle detectors should be taken into account.

10.13.2.7 Contingency procedures

Contingency procedures should be planned so that repairs can be performed if any damage occurs during pipelaying operations.

NOTE Possible types of damage include:

a) dry buckle;

b) wet buckle;

c) loss of weight coating;

d) loss of corrosion coating;

e) abandonment and recovery.

The pipelay start-up head should be equipped with the necessary valves and pre-installed pigs to enable the pipeline to be de-watered in the case of a wet buckle.

10.13.2.8 Instrumentation and recording

Instrumentation should be provided to monitor and record:

a) pipe tension at each tensioner;

b) total tension;

c) tension and footage of constant tension winch during abandonment and recovery;

d) barge and stinger roller loadings;

e) pipeline position with respect to stinger tip;

f) stinger configuration and tip depth, if buoyant;

g) anchor cable loads.

10.13.3 Towing methods

10.13.3.1 General types of tow

NOTE General types of tow include:

a) bottom tow (including off-bottom tows), in which the pipeline remains in contact with or in close proximity to the seabed;

b) mid-depth tow, in which the pipeline is towed well clear of the seabed yet remains submerged well below the water surface;

c) surface or near-surface tow, in which the pipeline is supported by temporary buoyancy.

Surface tow methods are only used for short lengths of pipeline or where wave and current actions are minimal.

Notification should be given to operators of pipelines and cables that will be crossed during a pipeline tow operation, the coastguard, fishermen and other users of the sea.

A monitoring vessel should be used to prevent interference with the pipeline by third-party vessels. A precise material and weight control system should be implemented during fabrication.

The individual pipe strings should be hydrostatically tested prior to tow-out in addition to other hydrostatic testing recommendations (see Clause **11**). The need for air testing of the sleeve pipe to confirm its integrity should be assessed.

10.13.3.2 Procedures

Procedures should be prepared for:

a) towing route survey;

b) make-up of pipe string onshore;

c) ballast control;

d) pipe string configuration analysis;

e) weather restrictions and contingency for adverse weather conditions;

f) pipe string positioning during tow and for placement;

g) pipeline/cable crossing procedures;

h) deballasting;

i) tie-in;

j) implementation of contingency plans;

k) monitoring the towing tensions.

10.13.3.3 Bottom tow

Care should be taken to ensure that the pipeline route avoids rock outcrops or other obstacles that could damage the pipeline, coating or anodes during installation. The selected pipe coating system should be protected from, or resistant to, abrasion damage during the tow.

10.13.3.4 Mid-depth tow

The towing speed and tensions should be controlled and monitored to maintain the required pipeline configuration. Profile measurements during the towing operation should be made for configuration confirmation.

10.13.4 Reel lay method

10.13.4.1 Procedures

Procedures should be prepared for:

a) loading the reel;

b) start-up;

c) lay-down;

d) control of tension;

e) abandonment and recovery;

f) installing/joining additional pipe strings;

g) implementation of contingency plans.

10.13.4.2 Laying

Account should be taken of the effect on material characteristics, coatings and circumferential welds. The possibility of buckling and excessive ovality of the pipe should be taken into account. Flexible pipelines should be laid in accordance with the manufacturer's recommendations (see **6.5**).

Steel pipe should be unreeled and straightened prior to or during passage through a tensioner. The reel should not be used to control the tension of the pipeline during laying, unless it can be shown that there are unlikely to be any detrimental effects.

10.13.4.3 Loading the reel

Fabrication of the pipe strings should be performed in accordance with **10.10**. The pipe should be supported during reeling and measures should be taken to prevent damage to protective coatings.

A sample of pipe should be passed through the pipe straightener to test the setting during mobilization of the vessel to determine whether ovality and straightness are maintained within the necessary limits.

10.13.4.4 Anodes

NOTE It is usually necessary to install anodes after the pipe has passed through the straightener and tensioner.

The anodes and their attachment should be designed to pass through trenching equipment if post-lay trenching is to be performed.

10.13.5 J-lay method

10.13.5.1 Procedures

Pipelines in deeper water may be installed by the J-lay method. Procedures are needed for all stages of the operation and should follow the recommendations for the S-lay method given in **10.13.2**.

10.13.5.2 Pipeline fabrication

The method of J-lay fabrication should be assessed and defined based on the vessel configuration.

NOTE Pipes may be joined either in the horizontal position and upended or in the vertical position, dependent on the installation vessel capability. Different welding techniques might be needed for each position.

10.13.5.3 Laying

The pipe should be maintained under controlled tension to ensure that the catenary profile is maintained and that stresses do not exceed the limits given in **6.4.2** or allowable strains given in **6.4.3**.

10.13.6 Other installation techniques

The strapping arrangement of bundles should be such that the smaller line cannot slip and that it does not foul any part of the installation equipment.

Precautions should be taken when trenching these pipelines to minimize the possibility of damage to the smaller pipe.

NOTE Other installation methods may be used in particular instances.

10.14 Span rectification

10.14.1 General

Span rectification should be undertaken when the state of the span is unacceptable in terms of the criteria given in **6.9** or where there is a need to avoid spanning because of potential damage from fishing activities or a risk of upheaval buckling.

In some situations, the presence of a pipeline span, although deemed acceptable structurally, can have potential for interference with fishing vessels and their gear as well as other legitimate users of the sea. Where the possibility of interaction is identified and the risk created to fishing vessels or other users of the sea is unacceptable then action should be taken to rectify the span. Regular inspection surveys should be undertaken.

10.14.2 Seabed preparation

Pre-lay seabed preparation should be undertaken if the predicted span exceeds the allowable span length for the as-laid, empty, construction load condition (see **6.9**). The preparation should include:

a) infilling of seabed depressions;

b) removal of high-spots.

Pipe lay tolerances should be taken into account in determining the width of the prepared corridor.

10.14.3 Post-lay span rectification

Account should be taken of the potential for span generation and extension resulting from scour or differential seabed settlement.

10.15 Pipeline crossings

10.15.1 General

Crossing locations, anchor patterns and handling should be pre-determined and agreed by all parties prior to installation (see **6.10**).

10.15.2 Pre-set supports

The location, position and condition of the existing pipeline should be accurately established prior to setting the supports. Vessel anchoring should be conducted in accordance with **10.11.2** for crossing other subsea installations. Owing to the close tolerances necessary, the crossing should be monitored by ROV to confirm proper placement of the pipeline.

NOTE Horizontal surface positioning systems alone are not normally sufficiently accurate to position the pipeline over the supports.

A continuous support and a smooth profile over the pipeline should be achieved to reduce risk of damage to the pipeline and fishing vessels from impact.

10.16 Pipeline tie-ins

10.16.1 Stresses

Installation stress induced in short discrete sections of pipe such as expansion offsets and post-installed risers should be controlled to below the limits determined in accordance with **7.3**.

Tie-in ends should be positioned within the tolerances determined in the design stress analysis. If the as-built positions and dimensions of the tie-in are outside the allowable analysis limits, a new analysis should be carried out to determine the acceptability of the tie-in configuration.

10.16.2 Jointing

10.16.2.1 Hyperbaric (dry habitat) welding

Following hyperbaric welding, the exposed joint should be protected against corrosion (see Clause **9**).

10.16.2.2 Mechanical jointing systems

Mechanical jointing systems should be protected by a shroud or cable deflector to prevent cables snagging. When flanges are used for tie-ins, the need for use of a swivel or lap type flange, usually on the installed spool side, should be assessed.

NOTE 1 This facilitates the alignment of the bolt holes of the two mating flange faces.

Hydraulic bolt tension equipment should be used for all flanged connections.

NOTE 2 Many proprietary connector systems allow a degree of axial misalignment which can greatly simplify the tie-in operation.

10.16.3 J-tubes

NOTE If J-tubes are installed, they are usually fitted during platform fabrication.

Before the pipeline is installed:

a) the J-tube bell-mouth should be clear of debris or obstruction;

b) the height of the bell-mouth above the seabed should be within design limits;

c) the bell-mouth, J-tube, and J-tube clamps should be undamaged.

Pipeline installation should be performed by a pull-in winch located on the platform. The cable tension should be monitored by calibrated load cells. Entry of the pipeline into the J-tube bell-mouth should be monitored by an ROV, and if the pull-in is taking place directly from a pipe lay vessel, the touch-down point of the pipeline on the seabed should also be monitored.

Corrosion inhibition and sealing of the annulus of the J-tube should be performed as soon as possible after the pull-in is complete.

10.17 Landfall

10.17.1 Site considerations

10.17.1.1 General

The following factors should be taken into account for any construction scheme:

a) access to site;

b) onshore plant and equipment;

c) site accommodation and services;

d) onshore construction procedures;

e) offshore plant and equipment;

f) temporary works;

g) permanent works;

h) discharge of chemicals;

i) use of explosives;

j) reinstatement;

k) trenching and protection requirements;

l) proximity to other services;

m) possible breaching of sea defence works;

n) impact on environmentally sensitive areas;

o) soil conditions at the landfall location;

p) seabed movement.

10.17.1.2 Pipeline location and marking

The location of any pipelines, cables, or outfalls in the area of the landfall should be determined and clearly marked.

10.17.2 Bottom pull

Where it is necessary to reduce pull loads, buoyancy tanks should be attached to the pipeline. If buoyancy is applied, its effect on the stability of the pipe should be taken into account. When a cable is used to pull the pipe, care should be taken to prevent twisting.

10.17.3 Directional drilling

Where geophysical and geotechnical surveys show that it is feasible, and where environmental and practical considerations restrict other methods, directional drilling should be used.

The following factors should be taken into account:

a) containment and disposal of drilling fluid;

b) selection of a corrosion protection system with high resistance to abrasion and low surface friction;

c) the stability of the pipeline before it is pulled into the directionally drilled hole;

d) the accuracy of determining the drill exit point and the impact of accommodating this on the construction works;

e) the implications of a breach of flood defences when using directional drilling for landfall construction. The relevant authorities, e.g. Environment Agency, should be consulted on measures to be taken to ensure that connectivity between the seaward side and the land behind flood defences does not cause a potential for flooding.

10.17.4 Protection methods

An appropriate protection method should be selected from the following:

a) trenching and backfilling;

b) concrete culvert;

c) shaft and tunnel.

Requirements for inspection and maintenance should be taken into account if either method b) or method c) is adopted.

10.18 Pipeline protection

10.18.1 Trenching

10.18.1.1 General

The trenching depth and profile should be controlled within the limits defined during the design phase to ensure that the pipeline is not overstressed during trenching or operation. Loads imposed on the pipeline during trenching should be monitored. Account should be taken of the extra loads imposed if the pipeline is flooded. Periodic monitoring for boulders, debris and excessive spanning should be carried out. Trenching methods and equipment should be selected to prevent damage to the pipe, coating and anodes and should be suitable for the soil conditions.

The pipe profile data and loads imposed to the pipe should be monitored and recorded. The strength criteria should not be exceeded.

10.18.1.2 Jetting

NOTE Jetting is suited to weak clays and non-cohesive soils.

If jetting is used, care should be taken to maintain an even profile and to avoid damage to the coating when using jet sleds.

10.18.1.3 Ploughing

A plough should be selected and operated to limit the stresses induced in the span behind it. Where a plough is powered by a subsea tractor, account should be taken of the seabed profile and the presence of boulders.

10.18.1.4 Mechanical cutting

NOTE Mechanical cutters are suited to cohesive soils and rock.

If mechanical cutters are used, they should employ pipe-tracking systems enabling them to trench the pipeline without physical contact with it.

10.18.1.5 Dredging

NOTE Dredging is used in shallow water prior to pipeline installation.

Where dredging is carried out, care should be taken to control the dredged profile to reduce the potential for pipeline spanning.

10.18.1.6 Instrumentation

Trenching equipment should be provided with instrumentation to monitor:

a) pitch, roll, heading, depth, and speed of machine;

b) trench profile;

c) tractive force;

d) load on rollers.

10.18.2 Bags, mattresses, gravel and stone placing

Selected material should be placed in such a manner as to achieve a smooth profile and to avoid damage to the pipeline and its coatings (see **7.6.2.6**).

10.19 Flooding, cleaning and gauging

10.19.1 General

Following construction, the pipeline sections should be cleaned by the passage of suitable pigs to remove any dirt or debris. Flooding and gauging of the pipeline should be performed after pipeline installation is completed. Prior to flooding, any free spans greater than that allowable for the flooded condition should be rectified.

10.19.2 Flooding

Flooding (filling) should be carried out in accordance with **11.6.2**.

10.19.3 Gauging

Gauging to confirm the bore of the pipe should be performed with a pig equipped with a gauging plate or with an internal geometry pig. Prior to running a gauging pig the line should be cleaned.

The pigs should be constructed of a material that is not likely to harm the inside of the pipeline.

The gauge plate diameter should be not less than 95% of the minimum internal diameter of the pipeline minus 3.0 mm for weld bead penetration, or 25 mm less than the minimum internal diameter, whichever is the larger.

10.20 As-built survey

The as-built surveys should provide an accurate record of the position and state of the pipeline and associated permanent works.

Survey records should include video tapes and acoustic records of the pipeline, together with drawings showing the pipeline with at least the following marked:

a) kilometre posts;

b) pipeline markers;

c) pipe numbers and weld numbers;

d) free spans and their dimensions;

e) trench profile and depth of cover;

f) bathymetry;

g) scour;

h) damage and repairs;

i) associated works;

j) debris;

k) anodes;

l) riser clamps and pipe supports;

m) pig traps;

n) landfall details (see PD 8010-1);

o) valves and other fittings;

p) pipeline position (eastings and northings).

11 Construction – Testing

11.1 General

Pipelines should be pressure-tested hydrostatically after all construction work has been completed, to determine their strength and leak-tightness prior to commissioning.

NOTE 1 Prefabricated assemblies and tie-in sections may be pre-tested before installation provided that no subsequent construction or installation activity is likely to impair the component integrity.

NOTE 2 Pneumatic testing is not acceptable for a strength test.

The pressure test should follow an approved procedure and should address provision for relieving excess pressure.

Equipment which is not to be subjected to the test pressures should be isolated from the pipeline or replaced by flanged test spools during testing. This should be achieved by introducing battery limit isolations to clearly limit portions of the system under test.

Valves should not be used as end closures during pressure-testing, unless rated for the differential pressure across the valve during testing. All devices used as end closures should have current certification defining sufficient strength to withstand the test pressure.

Temporary testing manifolds, temporary pig traps and other testing components connected to the test section should be designed and fabricated to withstand the internal test pressure of the pipeline. Temporary testing equipment should also have full documentation and its working pressure should be greater than or equal to the pipeline test pressure.

Pre-tested assemblies should be tested to at least the test pressure that is necessary for their location within the pipeline system (see **11.11**).

All testing should be carried out under the supervision of a suitably experienced and competent engineer.

11.2 Safety

11.2.1 General

Work on, or near, a pipeline under test should not be permitted for the period from the start of the increase in pressure to the reduction in pressure at the end of the test, except where necessary for conducting the test. Where appropriate, precautions such as reducing test pressure to allow test personnel to work on the pressurized pipeline should be applied.

The safety of the public, construction personnel, adjacent facilities and the protection of the environment should be ensured throughout testing operations. Depressurizing should be carried out by reducing the pressure in a controlled manner.

WARNING. Attention is drawn to:

a) potential hazards involved in pressure-testing, due to the release of stored energy;
b) environmental noise limitations;
c) safety of personnel regarding dispersion of the test medium to a safe area.

11.2.2 Precautions

All crossings and areas of public access should be patrolled during the period of the test to prevent access. Warning notices should be erected indicating that testing is in progress.

Boundaries should be clearly marked around the test equipment at each end of the section being tested, to deter persons not involved with the testing from approaching closer than the recommended safety distances.

NOTE 1 The typical safety distance for hydrostatic testing is 15 m.

For high-level hydrostatic testing, safety distances should be established and enforced by persons with the relevant expertise and competence.

NOTE 2 Guidance is given in HSE publication GS 4 [40].

NOTE 3 PD 5500 gives a general list of issues to take into account for pneumatic testing.

11.2.3 Cold weather

In cold weather, after the completion of hydrostatic testing, all lines, valves and fittings should be drained completely to prevent frost damage.

11.2.4 Temporary pig traps

Care should be taken in the operation of temporary pig launchers and receivers during the test and these should not be opened unless the pressure in the launcher or receiver is zero.

Any temporary pig traps attached to a pipeline under test should be isolated from the pipeline, unless they are designed and fabricated to the same standard as the pipeline.

11.3 Equipment

11.3.1 General

Hydrostatic testing equipment should be selected to be appropriate to the test pressure and should include the following:

a) deadweight tester (DWT) or previously calibrated pressure data logger;

b) pressure gauges;

c) volume-measuring equipment;

d) temperature-measuring equipment;

e) pressure- and temperature-recording equipment.

Instruments and test equipment used for the measurement of pressure, volume and temperature should be certified for accuracy, repeatability and sensitivity. Gauges and recorders should be checked immediately prior to each test and be calibrated when necessary. DWTs should be certified within the 6 months preceding the test or more often if heavy use requires it. DWTs should not be used in unstable situations (e.g. diving support vessels). All test equipment should be located in a safe position outside the boundary area (see **11.2.2**).

11.3.2 Measurement of pressure

Hydrostatic test pressure should be measured by a DWT having an accuracy greater than ±0.01 N/mm² (±0.1 bar) and a sensitivity of 0.005 N/mm² (0.05 bar). Where electronic pressure monitoring instruments are used on a vessel they should meet the same accuracy and sensitivity recommendations as a DWT. Pressure gauges should be selected with ranges that show between 50% and 90% of full-scale deflection at the test pressure.

11.3.3 Measurement of volume

The volume of liquid added or subtracted during a hydrostatic test should be measured by equipment having an accuracy greater than ±1.0% and a sensitivity of 0.1% of the calculated volume of liquid to be added after line filling has been completed, to produce, in the test section, the recommended test pressure (see **11.5**). Where pump strokes are used to determine the added volume, an automatic stroke counter should be used.

11.3.4 Measurement of temperature

Temperature measuring equipment should have an accuracy of ±1.0 °C and a sensitivity of 0.1 °C.

11.3.5 Recording equipment

Pressure and temperature recording equipment should be used to provide a graphical record of the test pressure and the variation of temperature for the duration of the test.

11.4 Pressure-testing

11.4.1 General

Pressure-testing should be carried out hydraulically. The selection of the test method should be based on a rigorous assessment of safety issues associated with the stored energy and the practical issues associated with the test arrangements.

NOTE 1 Re-routeing of short pipeline sections or short tie-in sections for pipelines in operation are examples of situations for which pressure tests with water might not be expedient.

*NOTE 2 Pipelines designed to convey category C substances that operate at a design factor of 0.3 or less may also be tested pneumatically using dry, oil-free air or nitrogen (see **11.4.2**).*

Reliable communications should be provided between all points manned during testing.

11.4.2 Test medium

Where possible, pressure tests should be conducted with water. Samples should be analysed and suitable precautions taken to remove or inhibit any harmful substances.

NOTE 1 Special care is needed in dealing with water sources containing potentially harmful chemicals or bacteria; it is advisable to take specialist advice.

Water for testing and any subsequent flushing should be clean and free from any suspended or dissolved substance that could be harmful to the pipe material or internal coating (where applied) or form deposits within the pipeline. Such water should be filtered to 50 μm as a minimum.

NOTE 2 Where it is not possible to use water as a test medium, product may be used if appropriate.

NOTE 3 Attention is drawn to the need to obtain extraction and disposal licences from the appropriate Environmental Agencies.

If the test medium is subject to thermal expansion during the test, provisions should be made for relieving excess pressure and measuring the displaced fluid volume.

11.4.3 Inhibitors and additives

If test water analysis indicates that inhibitors and additives, such as corrosion inhibitors, oxygen scavengers, biocide and dyes, are necessary, then account should be taken of their interaction and the effect on the environment during test water disposal. Account should also be taken of the effect of any such additives on the materials throughout the pipeline system.

11.5 Type and level of test

11.5.1 General

The type and level of test and the associated test pressure should be selected according to the proposed operation of the pipeline.

NOTE There are two basic types of test:

- *hydrostatic strength test (**11.5.2**);*
- *leak test (**11.5.3**).*

For the safety margin between the test pressure and the MAOP to be deemed adequate, the pipeline should meet the criteria given in **11.6**.

The pressure at the point of application should be such that the test pressure is generated at the highest point in the section under test. The additional hydrostatic head at any point in the section should not cause a hoop stress in excess of the SMYS of the material at that point.

11.5.2 Hydrostatic strength test

The hydrostatic test pressure should be not less than the sum of the MAOP plus any allowance for surge pressure and other variations likely to be experienced by the pipeline system during normal operation.

The minimum hydrostatic strength test pressure used to qualify a pipeline should be the lower of:

a) 150% of the internal design pressure; or

b) the pressure that is expected to result in a hoop stress (based on t_{min}) equal to 90% of the specified minimum yield stress.

The test pressure should be referenced to a fixed datum which is constant over the whole pipeline system, such as the lowest astronomical tide (LAT), and due allowance made for the elevation of the pressure measuring point and parts of the system above the reference datum.

11.5.3 Leak test

*COMMENTARY ON **11.5.3***

A leak test, which can be either hydrostatic or pneumatic, involves testing to a pressure of not less than 110% of the MAOP. Successful completion of the test at this level demonstrates pressure containment at the MAOP for future operation.

A leak test should be carried out in cases where the pipeline safety margin has been demonstrated by alternative methods not requiring high-level or standard testing (i.e. SRA and inspection).

11.6 Test procedure

11.6.1 General

Unless pipeline valves have a provision for pressure equalization across the valve seats, the need to pre-fill the valve body cavities with an inert liquid should be assessed. All valves should be left fully open during line filling and may be partially closed prior to pressure-testing.

11.6.2 Filling rate

Filling should be performed at a controlled rate.

Vent and drains points to facilitate filling and emptying should be provided to accommodate local pipeline and pipework configurations.

NOTE During filling, one or more pigs or spheres may be used to provide a positive air/water interface and to minimize air entrainment.

Where the fill rate is slow and there are steep downhill sections it can be necessary to maintain an air pressure to inhibit pigs running ahead of the line-fill. A safe limit of any such air backpressure should be established and carefully maintained.

A pig location device should be used to track or locate the pig and hence the interface position, and to control the pig speed. Pumps should be selected to achieve a fill rate of not less than 0.3 m/s. The maximum velocity of the pig should be limited to equal the water injection rate, to avoid pump cavitation and therefore the possible introduction of air.

11.6.3 Temperature stabilization

Time should be allowed after filling for the temperature of the water in the pipeline to stabilize with that of the pipeline environment. Where possible, the temperature of the fill water and the subsea temperature should be recorded to allow an estimate of the stabilization duration to be made.

11.6.4 Pressurization

The pressure in the test section should be raised at a controlled rate.
The volume of water added, the corresponding pressure rise and the time should be logged during this operation, and the air content calculated in accordance with **11.6.5**. On attaining test pressure, a period should be allowed for pressure stabilization during which residual air continues to go into solution and time-dependent straining of the pipe can take place. On completion of the stabilization period the pressure should be returned to the nominated test pressure and locked in. The pressure should then be held for a period of not less than 24 h.

NOTE The reason for the 24 h hold period is to ensure the detection of small leaks in large pipelines, and to cover the possibility of creep mechanisms causing failure after a number of hours.

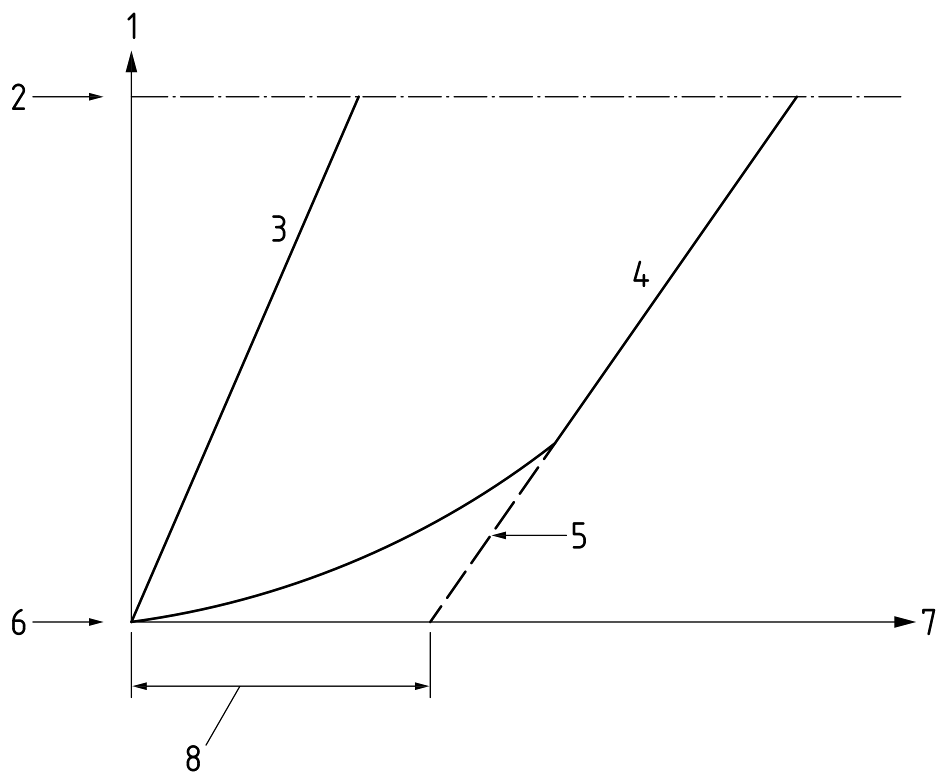
The rate of pressurization may be 0.1 N/mm^2/min (1 bar/min) up to 95% test pressure and 0.05 N/mm^2/min (0.5 bar/min) up to test pressure. Hold periods for checking leakage of a minimum duration of 30 min should be made for checking air content and at 60% and 90% test pressure.

11.6.5 Air content

Where the air content could affect the accuracy of the hydrostatic test, it should be determined and accounted for during the evaluation of the test results.

The measurement of air content should be carried out by constructing a plot of pressure against volume (see Figure 6) during the initial stage of pressurization until a definite linear relationship is apparent. By extrapolating this linear curve back to the volume axis, the air volume can be assessed, and compared with the total volume of the test section.

Figure 6 **Measurement of air content**



Key

1 Pressure

2 50% of internal design pressure or 3 N/mm^2 (30 bar), whichever is lower

3 Theoretical pressure/volume plot

4 Elastic line

5 Extrapolated

6 Static head pressure

7 Volume of water added

8 Volume of air

A comparison should also be made between the linear slope of the pressure/volume relationship for 100% water content. If these two slopes differ by more than 10%, the test section should be refilled.

The air content should not normally exceed 0.2% of the calculated capacity of the pipeline section under test, except by agreement for low-pressure systems where this might not be achievable. However, the hydrotest may be allowed to proceed with a higher air content provided that:

a) allowance is made for the additional residual air in the evaluation;

b) the test duration is extended accordingly.

NOTE For short sections of pipework within the system, where insufficient air venting facilities are available, a higher air content might be unavoidable (see Figure 6).

11.6.6 Pressure and temperature monitoring

A continuous record of the pipeline pressure and temperature should be made throughout the pressurizing, stabilizing and hold periods. The pressure and temperature should also be logged simultaneously at least every 30 min.

11.6.7 Written procedures

Written procedures for pressure tests should be prepared prior to the beginning of testing. These should include the following as appropriate:

a) profile, including the pipe grade and wall thickness, riser and landfall with the test pressure specified;

b) safety provisions;

c) need for continuous monitoring;

d) source and composition of test water and its disposal;

e) equipment to be used in the test;

f) all pressures and durations;

g) evaluation of the test results;

h) acceptance criteria;

i) leak-finding procedure.

11.6.8 Hydrostatic testing

The pressure in the test section should be raised at a controlled rate to the test pressure determined in accordance with **11.5**. The volume of water added, the corresponding pressure rise and the time should be logged during this operation, and the air content calculated. A period should be allowed for stabilization, during which residual air continues to go into solution and time-dependent straining of the pipe can take place. Test pressure should then be held for a period of 24 h. Pressure and temperatures should be recorded every 30 min, and the volume of any water added to maintain test pressure should be noted.

NOTE For volumes of less than 20 m^3 or for uncovered sections which can be fully inspected visually, this duration may be reduced.

11.6.9 Test data recording

Where practicable, a record of pressure, volume change, ambient temperature should be compiled over the full duration of a pipeline pressure test. The record of pressure and temperature should be monitored and recorded throughout the test.

11.6.10 Leak-finding

Leak detection and location procedures should be developed as part of the hydrostatic test procedure (**11.6.8**).

11.7 Acceptance criteria

The pipeline being tested should be deemed to have passed the test if it is free from leaks and if no observable pressure variation occurs during the hold period which cannot be accounted for by temperature change, taking into account the accuracy and sensitivity of the measuring equipment or by making allowance for temperature variation and/or volume of liquid bled off.

11.8 Post-test procedures

11.8.1 Depressurization

The rate of depressurization should be recorded in the test specification.

NOTE After completion of the test, the pipeline may be depressurized at a rate of 0.1 N/mm²/min (1 bar/min) down to 90% test pressure and thereafter at a rate of 0.2 N/mm²/min (2 bar/min).

11.8.2 Disposal of test fluids

Test fluids should be disposed of in such a manner as to minimize damage to the public and the environment.

Arrangements should be made for the disposal of test water from the pipeline section after completion of pressure-testing, bearing in mind that it might be heavily discoloured with rust particles. Consents should be obtained from the relevant authorities.

11.9 Repairs to test failures

Any pipeline which fails a pressure test should be repaired and re-tested. The failed portion should be replaced and the welds subjected to both radiographic and ultrasonic inspection in accordance with BS 4515-1 and BS 4515-2.

For pipelines subjected to high-level testing, repairs should be carried out using pre-tested pipe. The pipeline or section should then be re-tested for an aggregate period of not less than 24 h.

11.10 Non-pressure-tested closure welds (golden welds)

Consecutive test sections should be constructed to overlap so that the tie-in can be made with a single weld. If the tie-in cannot be made without using a length of pipe, this length of pipe should be pre-tested in accordance with **11.11** before installation. All tie-in welds not subject to subsequent pressure-testing should be subject to a regime which should be not less than the following:

a) visual inspection of the preparation;

b) dye penetrant (DP) or magnetic particle inspection (MPI) of weld preparation looking for laminar and pipewall defects;

c) visual inspection of the total welding process;

d) 100% radiography and/or 100% ultrasonic testing (UT) and DP or MPI on completion of welding.

Where post-weld heat treatment (PWHT) is required, it should be carried out after step c) and prior to step d).

The number of golden welds should be kept to a minimum on a pipeline.

11.11 Pre-testing

11.11.1 General

Pipe and fittings should be pre-tested in the following circumstances:

a) when they cannot be tested after installation in subassemblies to be incorporated into an existing installation;

b) when they are to be installed in close proximity to operating plant which cannot be protected against test failure;

c) when it is considered that the potential consequences of a test failure justify pre-testing.

Pre-testing of pipe or fabrications should be carried out in accordance with **11.4**, **11.5** and **11.6** except that:

1) the pre-test pressure should be at least 1.05 times the test pressure appropriate to the section into which the crossing is to be installed, taking into account the elevation of the crossing within the test section; and
2) the duration of the final hold period should be not less than 3 h.

The pipeline being tested should be deemed to have passed the test if no leaks are detected on visual examination.

11.11.2 Fabricated components

Fabricated components (such as risers and tie-in spools) and fabricated components (such as pig traps, slug catchers valves, insulation joints or manifolds) should be pre-tested before installation in the pipeline system. The test pressure should be calculated as described in **11.4**, **11.5** and **11.6**. The test duration should be not less than 6 h and should ideally be 24 h. In the unusual circumstances where assemblies will be not subjected subsequently to the full pipeline hydrotest, the test duration should be not less than 24 h.

This test should be carried out using the same procedures as the main pipeline (see **11.4**, **11.5** and **11.6**).

11.11.3 Bundles

The need for pre-testing of the onshore fabricated bundles should be assessed.

*NOTE Onshore-fabricated pipelines and bundles may be pre-tested (see **11.11.2**) before installation.*

11.11.4 Reeled pipe

The need for pre-testing of the onshore fabricated pie strings should be assessed.

*NOTE Onshore-fabricated pipe strings may be pre-tested (see **11.11.2**) prior to loading onto the reel of a reel ship.*

11.12 Test documentation and records

All certificates and records produced in connection with pressure-testing a pipeline should be retained by the operator for the lifetime of the system. The documentation should include:

a) test medium, duration and acceptance signature;
b) pressure recorder charts;
c) test procedure;
d) description of the facility tested and the test apparatus;
e) name of the pipeline system operator;
f) name of the person responsible for carrying out the test;
g) name of the test company, if used;
h) date and time of the test;
i) minimum and maximum test pressures at the test site;
j) log of temperature, pressure and volume change taken every 30 min;
k) seawater, underground and air temperature, where appropriate at 3 h intervals;
l) calibration certificates of test equipment;

m) calculation for air content;

n) calculation of pressure/temperature relationship and justification for acceptance;

o) an explanation and disposition of any pressure discontinuities, including test failures, that appear on the pressure-recording charts.

11.13 Flexible pipelines

The response of flexible pipelines to hydrostatic testing differs from the response of steel pipelines. Flexible pipelines are liable to creep, and therefore stabilization should include a period for settlement of the composite structure.

11.14 Integrity leak-testing

Where the component parts of the installed pipeline have been hydrostatically strength-tested and assembled using mechanical connections (e.g. flanges, forged connectors) or such a connection has been disturbed following the strength test and has subsequently been reassembled, then the assembled system should be leak-tested.

In order for the joints under test to be deemed leak-free, there should be no leaks when a test pressure of not less than 1.1 times the MAOP of the pipeline is held for a period at least long enough to ensure that all leak paths can be verified.

NOTE 1 The test duration may be very short under some circumstances, e.g. if dye is used in the test medium and the joints are wrapped, or if joints are tested above water and any leakage would be visible.

NOTE 2 Relief valves might need to be isolated or locked to achieve the test pressure.

The test medium should preferably be water, but nitrogen with a helium trace may be used where water is not practicable. Product should only be used in extreme circumstances when no alternative methods are available and the safety of personnel in the vicinity of the pipeline can be assured. Fluorescent tracer dye should be used in the test water to facilitate the detection of leaks subsea.

NOTE 3 For environmental reasons, clear dyes are preferred.

12 Pre-commissioning and commissioning

12.1 General

Written procedures should be established for pre-commissioning and commissioning. Procedures should take into account the characteristics of the fluids, the need to isolate the pipeline from other connected facilities and the transfer of the constructed pipeline to those responsible for its operation.

Pre-commissioning and commissioning procedures, devices and fluids should be selected to ensure that nothing is introduced into the pipeline system that is likely to be incompatible with the fluids, or with the materials in the pipeline components.

12.2 Disposal of pipeline content

The appropriate regulatory authorities should be consulted before any material is discharged from the pipeline.

Any drinking water plant within 1 km of the discharge point should be closed for the duration of the discharge and for 24 h thereafter.

NOTE A plant outside a 1 km radius from the disposal point can still be affected because of its catchment area.

The location of any drinking water plant should be reviewed with respect to the groundwater hydrology.

12.3 Cleaning

Additional cleaning of the pipe and its components, beyond that recommended in **10.19**, should be carried out where necessary.

NOTE 1 Additional cleaning can be necessary to remove:

- *non-metallic particles, including residue from testing and millscale;*
- *metallic particles which could affect intelligent pig result interpretation;*
- *chemical residue from the test water inhibitor;*
- *organisms resulting from test water;*
- *construction devices such as isolation spheres used for tie-ins.*

Pipeline cleaning procedures should take into account the need for:

a) protection of pipeline components from damage by cleaning fluids or devices;

b) removal of particles that could contaminate the fluid;

c) removal of metallic particles that could affect intelligent pigging devices.

Measures should be taken to dispose of debris, and gels if used.

NOTE 2 Debris from the pipeline can block or contaminate small-bore branches or instrument tappings. It might be necessary to block off or remove the items.

12.4 Drying

12.4.1 General

Measures should be taken to remove residual water from a pipeline after de-watering in order to reduce corrosion or hydrate formation. Drying methods should be selected on the basis of the need for dryness to meet the quality specifications of the transported fluids. Dryness criteria should be established as at water dew-point temperature.

12.4.2 Drying procedures

Drying procedures should take into account:

a) compatibility with the quality specification for the transported fluid;

b) the effect of drying fluids and devices on valve seal materials, pipeline internal coating and other components;

c) the corrosion potential caused by a combination of free water and the drying fluids, especially for H_2S and CO_2 corrosion potential;

d) removal of water and drying fluids from valve cavities, branch piping and other cavities in the system where such fluids might be retained;

e) the effect of hydrate formation during commissioning.

12.4.3 Drying methods

Drying should be performed using one or more of the following methods:

a) propelling pigs through the pipeline by dry air or nitrogen;

b) passing a liquid drying agent (glycol or methanol) through the pipeline;

c) removing water vapour with vacuum pumps until the desired dewpoint is reached then purging with dry oil-free air or nitrogen.

The effects of drying using chemicals or a vacuum on seals of valves and pig traps should be taken into account.

An inert gas such as nitrogen should be used to separate methanol swabs and air.

If methanol is used, attention should be given to its hazardous and toxic nature.

WARNING. Methanol has a low flashpoint and forms explosive mixtures with air. It is poisonous when breathed or swallowed and can be absorbed through skin contact.

In large quantities methanol and glycol can be harmful to marine life. Prior consent for disposal should be obtained (see **12.2**).

12.5 Introduction of product

12.5.1 Start-up procedures

Written start-up procedures should be prepared before introducing the transported fluid into the system. Start-up procedures should include instructions to ensure that:

a) the system is mechanically complete and operational;

b) all functional tests are performed and accepted;

c) all necessary safety systems are operational;

d) operating procedures are available;

e) a communication system is established;

f) the completed pipeline system is formally transferred to those responsible for its operation.

During pipeline filling with the fluid, the rate of fill should be controlled and the fluid pressure should not be allowed to exceed permitted limits. Inhibitors should be introduced in the product stream where necessary to inhibit corrosion or prevent the formation of hydrates.

Leak checks should be carried out periodically during the filling process. Pigs or spheres should be used to minimize mixing at the interface of a liquid product and water.

12.5.2 Gas systems

For gas systems, measures should be taken to avoid the formation of the potentially explosive mixture of hydrocarbon gas and air when a gas product is introduced into a pipeline. Dry inert gas should be used to purge the pipeline of air prior to the introduction of product.

The gas injection rate should be controlled to ensure that the gas temperature does not drop below allowable limits for the pipeline material or the dewpoint of the gas.

12.6 Connections to operating pipelines

Where it is necessary to commission a pipeline that is connected to an operating pipeline, two-valve isolation with bleed facilities should be provided where practicable.

NOTE If this is not practicable, other options, e.g. a single valve with double block and bleed facilities, may be used provided that they are suitable for the category of fluid and the perceived level of risk.

12.7 Functional testing of equipment and systems

As a part of the commissioning, all pipeline monitoring and control equipment and systems should be fully functionally tested, especially safety systems such as pig-trap interlocks, pressure and flow-monitoring systems, and emergency pipeline-shutdown systems. A final test of pipeline valves should also be performed prior to the introduction of the transported fluid to ensure that they operate correctly.

12.8 Documentation and records

Pre-commissioning and commissioning records should include:

a) cleaning and drying procedures;

b) cleaning and drying results;

c) function-testing records of pipeline monitoring and control equipment systems.

Pre-commissioning and commissioning records should be retained.

13 Operation, maintenance and integrity assurance management

13.1 Management systems

13.1.1 General

An integrity management system should be established and implemented with the objectives of:

a) ensuring safe operation of the pipeline system;

b) ensuring ongoing compliance with the design;

c) managing processes that could affect the continuing integrity of the pipeline system, e.g. corrosion, erosion, control systems;

d) ensuring safe and effective execution of maintenance, modifications and abandonment;

e) dealing effectively with incidents and modifications.

The management system should include:

1) identification of personnel responsible for the management of the operation and maintenance of the pipeline, and for key activities;

2) establishment of rules and responsibilities of personnel within a formal organizational structure;

3) a written plan covering operating and maintenance procedures (see **13.1.2**);

4) a written emergency response plan, covering failure of pipeline systems and other incidents (see **13.1.3**);

5) a written permit-to-work system (see **13.1.4**);

6) a written plan for the control of change of design conditions;

7) requirements for training (see **13.1.5**);

8) requirements for liaison with third parties (see **13.1.6**);

9) requirements for the retention of records (see **13.1.7**).

The operation, maintenance and modifications of the pipeline system should be carried out in accordance with these plans.

*NOTE Abandonment is covered in Clause **14**.*

The management systems should be reviewed on a regular basis as experience dictates, and as required by changes in the operating conditions and in the pipeline environment.

13.1.2 Operating and maintenance plan

The operating and maintenance plan should include, where appropriate:

a) procedures for normal operations (see also **13.2**) and maintenance (see also **13.3**), which should define as a minimum:

   1) the pipeline system, including pumping stations, terminals, platforms and other installations, the operational envelope, the fluid to be conveyed and the process conditions;

   2) means of controlling and monitoring the pipeline system, including manning levels, instrumentation, location and hierarchy of control centres;

   3) individual and functional responsibilities and tasks;

   4) means of managing pipeline integrity;

   5) necessary safety precautions;

   6) interfaces with other pipeline systems and installations, upstream and downstream facilities. Procedures for dealing with interfaces with other pipeline systems and installations should be developed in consultation with their operators;

   7) relevant information and references to applicable rules and guidelines, schedules, inspection and maintenance specifications and instructions for each element of the pipeline system;

   8) relevant drawings and route maps;

b) requirements for personnel communications (voice and/or data);

c) requirements for spares and equipment;

d) a plan for the issue of procedures to cover non-routine operations and maintenance;

e) emergency shut-in procedures;

f) marine operations procedures (where applicable);

g) scheduling and dispatching procedures;

h) venting and flaring procedures;

i) any requirements identified from hydraulic analysis;

j) references to relevant legislation.

13.1.3 Incident and emergency response plan

NOTE 1 Attention is drawn to the Pipelines Safety Regulations 1996 [18], Regulations 12, 24 and 25 in respect of emergency procedures.

An incident and emergency response plan should be developed to meet the particular requirements of an individual pipeline system. The following aspects should be taken into account when developing the plan.

a) A description of the pipeline system should be compiled, including:
   - all related or interconnected facilities such as other pipelines, platforms and terminals;
   - all relevant technical data such as dimensions and the normal operational envelope parameters of working fluid, pressure, flow rate and temperature;
   - charts illustrating the geographic location of the pipeline and its isolation facilities.

b) The organization and personnel responsible for dealing with an emergency, including the person nominated to be in overall control, should be established and procedures developed to ensure that individuals understand their role. Appropriate training should be undertaken.

c) The role and location of the nominated control centre for dealing with an emergency should be established, and details should be identified of the communication media to be employed in contacting all parties involved.

d) Data regarding the significant characteristics of the working fluid and any other products that might be used during an emergency situation, together with any associated hazards, should be identified and documented.

e) Details of the notification of an incident should be recorded.

   NOTE 2 This could result from observation of abnormal conditions at a control facility or by information received from an outside source. This enables the control centre to establish and assess the nature and location of the incident and the resources to be deployed.

f) A procedure should be developed for mobilizing the necessary resources to deal with an incident and alerting the appropriate authorities. This should include a comprehensive list of contact telephone numbers and other communication media details. It should also include any known restrictions on access.

g) A clear procedure and understanding with the relevant authorities regarding the isolation and shutdown of the pipeline in an emergency situation should be established.

   NOTE 3 It is important that the control centre take charge of these events in the interests of safety of all involved.

h) Emergency equipment, including tools, plant, vessels, communications, electrical power, lighting, fire control, hazardous substance detection instruments, personal safety clothing, breathing apparatus, warning signs and any specialist items, should be detailed and kept in a state of readiness at nominated locations.

i) Remedial works required vary according to the nature of the specific incident. Procedures and guidelines should be developed as and when appropriate for particular tasks such as:
   - establishing cordon distances (in the event of potential fires or toxic releases);
   - dealing with pollution, fires or toxic releases;

- protection of adjacent facilities;
- venting/flaring of products, etc.

j) There should be provision for safe isolation of electrical or cathodic protection systems on damaged pipelines, to enable repair operations to be carried out.

The effectiveness of the plan should be tested periodically through desk and field simulations of incidents and emergencies.

NOTE 4 Such simulations may be carried out in cooperation with operators of other pipelines or facilities, organizations and individuals who are directly affected by an incident or emergency, or who contribute to the response. Other parties likely to be involved include personnel not normally involved with the routine operations, e.g. coastguards and marine authorities.

Causes of pipeline incidents and emergencies should be identified and analysed, and actions necessary to minimize reoccurrence should be implemented.

13.1.4 Permit-to-work system

The permit-to-work system should define the activities to which it applies, the personnel authorized to issue a permit-to-work, and the personnel responsible for specifying the necessary safety measures.

The permit-to-work system should be managed in parallel with an engineering change control system and should specify requirements for:

a) training and instruction in the issue and use of permits;

b) reviewing the effectiveness of the permit-to-work system;

c) informing personnel controlling the pipeline system of the work activity and all related safety requirements;

d) display of permits;

e) control of pipeline operation in the event of suspension of the work;

f) handover between shifts.

The permit-to-work should:

- define the scope, nature, location and timing of the work;
- indicate the hazards and define necessary safety measures;
- refer to other relevant work permits;
- state the requirements for returning the pipeline system to service;
- state the authorization for execution of the work.

13.1.5 Training

Training of personnel should include, where relevant:

a) familiarization with the pipeline system, equipment, potential hazards associated with the pipeline fluid, and procedures for operation and maintenance;

b) the use of permits-to-work;

c) the use of protective equipment and fire-fighting equipment;

d) provision of first aid;

e) response to incidents and emergencies.

13.1.6 Liaison

Contacts should be established and maintained with appropriate organizations and individuals, such as:

a) fire, police, coast guard and other emergency services for landfall activities;

b) regulatory and statutory authorities;

c) operators of other pipelines which connect to, cross, or run in close proximity to the pipeline;

d) third parties involved in any activity which could affect or be affected by the pipeline.

Pipeline route maps should be deposited with statutory authorities or "one-call" organizations, as appropriate.

NOTE A "one-call" organization collects information on underground facilities and, following notification of construction in the area, advises on the presence of these facilities. Local legislation can stipulate a requirement for soliciting information on the presence of underground utilities before commencement of work.

13.1.7 Records

In addition to as-built records and engineering changes, records of operation and maintenance activities should be prepared and retained to:

a) demonstrate that the pipeline system is operated and maintained in accordance with the operating and maintenance plans;

b) provide the information necessary for reviewing the effectiveness of the operating and maintenance plans;

c) provide the information necessary for assessing the integrity of the pipeline system.

As-built information should be provided to the owner/operator of the pipeline as soon as practicable after completion of the work. A documented handover of information before commissioning, including the as-built pipeline engineering dossier and the operation and emergency procedures, should be carried out to maintain safety. No pipeline should be commissioned without a handover of as-built engineering and operational information to all the relevant parties, i.e. the responsible people who will be filling, operating or taking from the pipeline.

13.2 Operation

13.2.1 General

Procedures for the operation of the pipeline system should define the envelope of operating conditions permitted by the design, and the operating requirements and constraints for the control of corrosion. Fluid parameters should be monitored to establish that the pipeline system is operated accordingly.

Procedures for the operation of multi-product pipeline systems should include requirements for the detection, separation and prediction of arrival of batches.

Procedures for the operation of multi-phase pipeline systems should include requirements for control of liquid hold-up in the pipeline and free volume at the reception facilities.

Deviations from the operating plan should be investigated and reported, and measures to minimize recurrence should be implemented.

NOTE Operational guidance is given in PD 8010-5.

13.2.2 Pigging

A pigging philosophy should be established for each pipeline system as part of the design. Procedures for pigging operations should include requirements for:

a) confirming that the pipeline is free of restraints or obstructions for the passage of pigs;

b) control of pig travelling speed;

c) safe isolation of pig traps;

d) contingencies in the event of a stuck pig.

13.2.3 Decommissioning

NOTE Attention is drawn to the Pipelines Safety Regulations 1996 [17], Regulation 14 in respect of decommissioning.

Pipelines that are planned to be out of service for an extended period should be decommissioned. Arrangements should also be made for the removal of fluids.

Decommissioned pipelines should be maintained in a safe condition, including maintenance of cathodic protection where necessary. Where no further use of the pipeline is planned, abandonment should be carried out in accordance with Clause **14**.

13.2.4 Re-commissioning

NOTE Attention is drawn to the Pipelines Safety Regulations 1996 [18], Regulation 21 in respect of re-commissioning.

The condition of a decommissioned pipeline system should be established and its integrity confirmed before re-commissioning.

Pipeline filling should be in accordance with **12.5**.

13.3 Integrity assurance management

13.3.1 Maintenance programme

NOTE 1 Attention is drawn to the Pipelines Safety Regulations 1996 [18], Regulation 7 in respect of maintenance access; Regulation 10 in respect of work on the pipeline; Regulation 13 in respect of maintenance; and Regulation 23 in respect of major accident prevention documents and safety management systems.

NOTE 2 Offshore written schemes of examination are covered by the need for verification schemes referenced in Regulation 19 of the Offshore Installations (Safety Case) Regulations 2005 [11].

NOTE 3 Integrity management guidance is given in PD 8010-4.

Maintenance programmes should be prepared and executed to monitor the condition of the pipeline and to provide the information necessary to assess its integrity.

Factors which should be taken into account when defining the requirements for condition monitoring include:

a) pipeline system design;

b) as-built condition;

c) results of earlier inspections;

d) predicted deterioration in the condition of the pipeline;

NOTE 4 Possible deteriorations in pipeline condition include general and pitting corrosion, changes in the pipe wall, geometry (such as ovality, wrinkles, dents, gouges), cracking (such as stress corrosion and fatigue cracking), changes in the pipeline position, support or cover, and loss of weight coating.

e) adverse subsea conditions;

f) inspection time intervals.

Unfavourable results, such as defects, damage and equipment malfunctioning, should be assessed and corrective action taken where necessary to maintain the intended integrity.

The maintenance programmes should cover the complete pipeline system. Particular attention should be paid to pipeline protection and safety equipment.

13.3.2 Route inspection

The pipeline route should be periodically surveyed to detect factors that could affect the safety and the operation of the pipeline system. The results of surveys should be recorded and monitored.

Surveys of the pipeline and adjacent seabed should identify:

a) mechanical damage to the pipeline, including leakage;

b) evidence of pipeline movement;

c) extent of marine growth;

d) condition of the adjacent seabed, including the presence of foreign objects;

e) extent of any free spans;

f) extent of any loss of cover along the buried or protected sections;

g) extent of any loss of weight coating;

h) security of pipeline attachments, including anodes and piggy-back pipelines, if applicable.

13.3.3 Monitoring pipeline integrity

13.3.3.1 Corrosion control

The maintenance programmes should include procedures for corrosion monitoring established for corrosion management in accordance with Clause **9**.

The quality and performance of corrosion inhibitors should be tested periodically to determine whether or not they are still effective, and appropriate remedial action should be taken where necessary.

13.3.3.2 Leak detection and surveys

The performance of the leak detection system should be reviewed and tested periodically to determine whether or not it continues to meet the recommendations given in **6.11**, and appropriate remedial action should be taken where necessary. Records should be kept of alarms and leaks to assist the performance review. Where appropriate, leakage surveys should be carried out to determine whether potentially hazardous leakage exists, and appropriate remedial action should be taken where necessary.

13.3.4 Monitoring pipeline facilities, equipment and components

13.3.4.1 Valves

Valves should be inspected periodically, moved and/or tested for correct operation. Where it is necessary to fully operate a pipeline valve, due account should be taken of the permissible pressure drop across the valve.

Remotely operable valves and actuators should be tested remotely to check the correct functioning of the whole system, and appropriate remedial action should be taken where necessary.

Pressure vessels associated with valve actuators should be inspected and tested periodically.

13.3.4.2 Protection devices

Protection devices, including actuators, associated instrumentation and control systems, should be inspected and tested periodically.

The inspection and testing should cover:

a) condition;

b) verification of installation and protection;

c) correct setting and activation;

d) inspection for leaks.

NOTE Protection devices include pressure control and overpressure protection, emergency shutdown isolations, quick-connect/disconnect connectors, storage tank level controls, etc.

Emergency shutdown valves, including actuators and associated control systems, should be inspected and tested periodically to determine whether the whole system functions correctly and whether valve-seal leakage rates are acceptable.

Particular attention should be paid to storage tank level controls and to relief valves on pressure storage vessels.

Appropriate remedial action should be taken where necessary.

13.3.4.3 Pig-traps and instrumentation

Instrumentation, telemetry systems, temporary pig traps and the data acquisition, display and storage systems essential for the safe operation of the pipeline system should be examined, tested, maintained and calibrated, and appropriate remedial action should be taken where necessary.

Maintenance procedures should cover the control of temporary disarming or overriding of instrumentation, for maintenance or other purposes.

13.3.4.4 Risers

Risers on offshore installations should be inspected periodically with particular attention paid to sections in the splash zone. These inspections should cover:

a) the condition of the riser pipe, including any loss of wall thickness, particularly under riser clamps/guides;

b) the condition of impact protection, fire protection, protective coatings, cladding and fitted anodes;

c) the condition of riser flanges or couplings;

d) the condition of attachment or clamping arrangements, and associated supporting structure;

e) changes in position of the riser;

f) the extent of marine growth.

The corrosion protection systems provided to risers enclosed in J-tubes or caissons should be frequently monitored.

13.3.5 Pipeline defects and damage

13.3.5.1 Initial actions

When a defect or damage is reported, the pipeline pressure should be maintained at or below the pressure at the time the defect or damage was first reported.

A preliminary assessment should be carried out by a fully trained and competent person and, if any unsafe condition is found, appropriate remedial action should be taken immediately.

NOTE At the time of reporting, the pressure might not necessarily be as low as the pressure within the pipeline at the time of occurrence.

13.3.5.2 Examination, inspection and assessment of defects

Care should be taken during preparation and examination of damaged and pressurized pipelines because of the possibility of sudden failure.

The pipeline operating pressure should be reduced to ambient conditions, e.g. when divers are to conduct an examination of an underwater pipeline, or to a stress level that is unlikely to lead to pipeline rupture.

Procedures should be established for assessment of pipeline defects and damages (see BS 7910 or API RP 579).

Defects and damage permitted under the original fabrication and construction specifications may remain in the pipeline without further action. For other defects, further assessment should be made to determine any requirement for pressure de-rating, repair or other corrective action. These assessments should include:

a) review of inspection and measurement data, including orientation of the defect and proximity to other features such as welds or HAZ;

b) details of the original design and fabrication specifications;

c) actual pipe-material mechanical and chemical properties;

d) possible modes of failure;

e) possible growth of the defect;

f) operating and environmental parameters, including effect on pigging operations;

g) possible consequences of failure;

h) monitoring of the defect where possible.

13.3.6 Pipeline repairs and modifications

13.3.6.1 General

Repair procedures should include the selection of repair techniques and the execution of repairs. Repairs should reinstate the intended integrity of the pipeline at the location of the defect or damage.

NOTE Pipeline defects and damage can be grouped under a number of headings, including:

a) pipewall defects, e.g. cracks including cracking caused by stress corrosion and fatigue, gouges, dents, corrosion, weld defects, laminations;

b) pipe coating defects, e.g. loss of wrap or concrete coating;

c) loss of support, e.g. spanning of pipelines;

d) pipe movement, e.g. upheaval buckling, frost heave and landslip, which can also result in buckling, denting or cracking.

13.3.6.2 Pipeline isolation

The selection of an isolation method should take into account:

a) hazards associated with the fluid;

b) required availability of the pipeline system;

c) the duration of the work activity;

d) the need for redundancy in the isolation system;

e) possible effect on pipeline materials;

f) possible locations for isolation points.

13.3.6.3 Venting and flaring

Hazards and constraints that should be taken into account when planning to vent or flare include:

a) asphyxiating effects and other localized effects (e.g. gas cloud formation) of vented gases;

b) ignition of gases by stray currents, static electricity or other potential ignition sources;

c) noise level limits;

d) hazard to aircraft movements, particularly helicopters in the vicinity of offshore installations and terminals;

e) hydrate formation;

f) valve freezing;

g) embrittlement effects on steel pipework.

13.3.6.4 Draining

Liquids should be pumped, or pigged, out of a pipeline using water or an inert gas. Hazards and constraints that should be taken into account when planning to drain include:

a) asphyxiating effects and other localized effects (e.g. gas cloud formation) of inert gases;

b) protection of reception facilities from overpressurization;

c) drainage of valve cavities, “dead legs”, etc.;

d) disposal of pipeline fluids and contaminated water;

e) buoyancy effects if gas is used to displace liquids;

f) compression effects leading to ignition of fluid vapour;

g) combustibility of fluids at increased pressures;

h) accidental launch of trapped pigs by stored energy when driven by inert gas.

13.3.6.5 Purging

Hazards and constraints that should be taken into account when preparing for purging include:

a) asphyxiating effects and other localized effects (e.g. gas cloud formation) of purge gases;

b) minimizing the volume of flammable or toxic fluids released to the environment;

c) combustion, product contamination or corrosive conditions when reintroducing.

13.3.6.6 Cold cutting or drilling

Procedures for cold cutting and drilling should specify requirements for preventing the accidental release or ignition of the fluid, and other unsafe conditions.

Where appropriate, the section of pipeline to be worked on should be:

a) isolated;

b) depressurized by venting, flaring or draining; or

c) purged.

A temporary electrical continuity bond should be fitted across any intended break in an electrically conductive pipeline before making such breaks.

13.3.6.7 Hot work

The following should be taken into account prior to carrying out hot work on pipelines in service:

a) possible physical and chemical reactions, including combustion of the pipeline fluids or their residues;

b) the type, properties and condition of the pipe material, and the wall thickness at the location of the hot work;

c) possible corrosion of pipe and welds.

Welding should be carried out in accordance with **10.10**.

The pressure, temperature and flow rate of the fluid through the pipeline should be monitored and maintained within the limits specified in the approved welding procedure.

All welds should be fully inspected during and after welding by visual examination and appropriate NDT techniques, such as radiography, ultrasonic testing and surface testing methods (magnetic particle and dye penetrant). Leak-testing of welds of sleeves, saddles, reinforcing pads or any associated fitting should be carried out before introducing fluids.

13.4 Changes to the design condition

13.4.1 Change control

A change control plan should be implemented that defines and documents procedures to be followed when handling changes in the design condition.

It should be demonstrated that the revised pipeline system and integrity meets the recommendations of this part of PD 8010 before implementing changes to the design condition, such as an increase in MAOP or change of fluid.
All documentation relating to the pipeline design and management-of-change records should be updated to reflect the revised design condition.

NOTE Any alteration to the pipeline registration under the Pipelines Safety Regulations 1996 [18] needs to be notified prior to a change in operation.

13.4.2 Operating pressure

An increase in MAOP can necessitate additional hydrostatic testing, inspection, additional cathodic protection surveys and other measures. When increasing operating pressures, pressures should be raised in a controlled manner to allow sufficient time for monitoring the pipeline system.

Where pipelines are permanently de-rated from pressures that cannot subsequently be reapplied to the pipeline because of a reduction in wall thickness through corrosion, stringent data and supporting calculations should be maintained to record the changes.

13.4.3 Service conversion

Prior to a change in service, including change of fluid, it should be demonstrated that the design and integrity of the pipeline is appropriate for the proposed new duty. A detailed review of as-built, operational and maintenance data of the pipeline should be made before implementing a change in service. Data to be reviewed should include:

a) original pipeline design, construction, inspection and testing;

b) all available operating and maintenance records, including corrosion control practice, inspections, modifications, pipeline incidents and repairs.

Particular attention should be paid to the welding procedures used, other jointing methods, internal and external coatings and pipe, valve and other materials.

13.4.4 New crossings and developments

At crossings, pipeline integrity should not be compromised. The effect of a new crossing on any existing cathodic protection should be investigated.

13.4.5 Testing of modified pipelines

All prefabricated pipeline assemblies, including spool pieces, should be pressure-tested in accordance with Clause **11** before installation in the pipeline.

Mechanical joints in pressure-containing parts of the pipeline which have been disconnected or disturbed should, as a minimum, be leak-tested and should not show signs of leakage during the test.

The medium for in situ pressure-testing should be, in order of preference to minimize risks:

a) water;

b) the normal pipeline fluid (if liquid);

c) an inert gas such as nitrogen (with a tracer element, if possible);

d) the normal pipeline fluid (if gas).

Modifications involving the use of welded tie-ins should be inspected in accordance with **11.10** if not pressure-tested.

Small diameter pipework and secondary piping should be tested to ensure the integrity of all joints and connections after any work activity where pipework has been disturbed.

14 Abandonment

14.1 Arrangements for abandonment

NOTE Attention is drawn to the Pipe-lines Act 1962 [41], Regulation 25 in respect of pipeline abandonment, and to the Pipelines Safety Regulations 1996 [18] in respect of general duties to preserve safety throughout the lifetime of the pipeline (including abandonment).

Pipeline systems planned to be abandoned should be decommissioned in accordance with **13.2.3** and disconnected from other parts of the pipeline system remaining in service.

A pipeline should be deemed to be disused when it has been abandoned or when the owners cease to inspect it regularly and are no longer prepared to maintain it in an operable condition.

When the owners are no longer prepared to maintain a disused pipeline in an operable condition, they should take precautions to prevent the pipeline from becoming a source of danger.

Before being abandoned, the pipeline should be completely disconnected at both ends and if necessary divided into sections. All open ends should be capped and sealed.

Where an abandoned pipeline cannot be made safe by this method, it should be removed. In all cases where the fluid conveyed is deemed to be an environmental or safety hazard, or could become so after contact with the soil, the fluid should be completely removed from the pipeline.

14.2 Records

A record should be kept by the operator of a pipeline to indicate that they have taken the necessary precautions. A record plan showing the size and depth of the pipeline and its location should also be prepared.

Annex A (normative) Quality assurance

A.1 Quality plan

The quality plan should set out specific procedures, resources and activities appropriate to the project, including control points and certificates of compliance and conformity. It should include procedures for:

a) environmental impact assessment;

b) integrity management;

c) risk management;

d) project and design auditing;

e) material source and identification;

f) welding, including welder qualifications;

g) inspection and acceptance;

h) pipe coating;

i) testing;

j) commissioning;

k) corrosion controls;

l) assessment of defects;

m) repairs and assurance;

n) modifications;

o) infrastructure and supports.

A.2 Design quality assurance

A.2.1 Design basis

A design basis manual should be prepared that includes details of as many of the following as are appropriate to the project:

a) site investigation;

b) design life;

c) ground surveys;

d) bore holes;

e) process design;

f) mechanical, civil, control, electrical and instrumentation design and specifications;

g) bills of materials;

h) environment and risk analysis;

i) maps, marine charts, drawings and schedules and equipment details;

j) operating and emergency procedures;

k) modifications and fitness for service assessments.

NOTE A typical design flowchart is illustrated in Figure 2.

A.2.2 Supervision

The design and construction of the pipeline system should be carried out under the supervision of a suitably experienced chartered engineer or equivalent.

A.3 Materials quality assurance

A.3.1 Pipe

The quality plan should specify the tests and documentary evidence required to ensure that the pipe, as delivered, meets the specification against which it has been ordered. Each heat of steel should be certified. Pipe mill inspection should be specified.

It should be possible to trace all materials used on the project back to material certificates. For major accident hazard pipelines (MAHPs), each accepted pipe should be given a unique identification number, cross-referenced to the inspection certification so that it can be identified and its quality verified. Each pipe used for the construction of such pipelines should be clearly marked with the unique pipe identification number, which should be maintained and transferred to any pipe offcuts.

NOTE Attention is drawn to the Pipelines Safety Regulations 1996 [18] in respect of MAHPs.

A.3.2 Stock material

Where material is purchased from stockholders, documentary certification (either of original manufacture or by appropriate testing) should be obtained from the supplier to demonstrate that the material supplied is in accordance with the required specification.

Fabrication should not commence until written certification is available or a means of traceability put in place to locate all uncertified materials.

A.3.3 Shop-fabricated or manufactured items

Shop-fabricated or manufactured items (e.g. pig traps, manifolds, slug catchers, valves, flanges, insulation joints, meters and meter provers) should not be used unless they are constructed from materials that can be identified and verified as to quality and specification.

A.4 Construction quality assurance

The construction quality plan should detail the procedures to be employed so as to control the construction process and the means of ensuring compliance. A method of recording and accepting or rejecting non-conformities should be developed.

The construction quality plan should identify the organization and responsibilities of those controlling the workmanship criteria. The procedures should include instructions for training, qualifying and periodic re-examination of personnel. Where the quality of workmanship is dependent on highly skilled or specially trained personnel, only those qualified to perform the work should be used.

The construction quality plan should also identify the inspection, certification and construction records and reports required to confirm the quality and safety of the constructed pipeline.

Annex B (normative) Records and document control

B.1 Design documentation

The following design documents should be included as appropriate for the nature of the pipeline:

a) design basis manual;

b) design audits, resultant change instructions and their implementation;

c) calculations and justification of assumptions relating to design, construction, testing, commissioning and operation;

d) materials and construction specifications;

e) maps, charts, drawings, schedules and sketches;

f) design verification;

g) modifications;

h) environmental impact and risk assessments;

i) external supports and infrastructure;

j) defect assessments;

k) cathodic protection documents.

B.2 Procurement documentation

The following procurement documents should be included as appropriate for the nature of the pipeline:

a) certificates of compliance, testing and identification of material;

b) NDT results and radiographs;

c) inspection reports;

d) weld procedure qualification certificates;

e) welder and NDT inspector qualification certificates;

f) manufacturing and fabrication procedures;

g) heat treatment certificates;

h) quality plans and manuals;

i) results of performance testing;

j) certificates and test results for support materials, infrastructure, and components;

k) material certificates.

B.3 Construction documentation

The following construction documents should be included as appropriate for the nature of the pipeline:

a) weld procedure qualification certificates;

b) welder and NDT inspector qualification certificates;

c) NDT inspection reports and radiographs;

d) weld repair reports and radiographs;

e) records of geographic location of pipe lengths and pipe joints by unique identification number;

f) coating inspection records;

g) weather reports;

h) anchor tensions and pipe tension;

i) towing reports;

j) installation procedures and quality plans;

k) vessel logs and position reports (cross-referenced to pipe reference numbers);

l) trenching and burial operations reports;

m) diving records including flange assembly records.

B.4 Pressure-testing and pre-commissioning documentation

The following pressure-testing and pre-commissioning documents should be included as appropriate for the nature of the pipeline:

a) selection of test sections with respect to hydrostatic head between high and low points;

b) filling procedure and records of pig run;

c) test procedure;

d) instrument calibration certificates;

e) test records including calculation of air content, half-hourly pressure log and pressure and temperature charts.

f) pre-commissioning records;

g) test diagrams showing test limits and the extent of each section tested, and relating this back to the various test reports;

h) location of non-pressure-tested closure welds and weld records.

B.5 Survey documentation

The following survey documents should be included as appropriate for the nature of the pipeline:

a) pre-construction hydrographic survey;

b) as-built survey including video records;

c) soils survey;

d) side scan sonar or any other acoustic records.

e) third-party crossing records;

f) cathodic protection survey records.

B.6 Inspection and maintenance documentation

The following inspection and maintenance documents should be included as appropriate for the nature of the pipeline:

a) written scheme of examination;

b) inspection reports;

c) defect reports;

d) defect assessment and fitness for service reports;

e) pig run reports;

f) records of repairs.

Annex C (informative) Hazards in pipeline design

C.1 Internal hazards

C.1.1 Substances conveyed as a liquid

Crude oil and refined petroleum products (heavier than butane) are flammable and are released as a liquid that can float on the surface and migrate a considerable distance from the point of release due to the action of winds and currents. Crude oil and petroleum products radiate a high level of heat on ignition.

Other toxic liquids can mix with water, but can be hazardous to marine life, depending on the concentration levels.

C.1.2 Substances conveyed as a gas

Nitrogen mixes with air but can form a heavier-than-air cloud on release (due to temperature reduction), increasing the risk of asphyxiation in the immediate vicinity.

Oxygen readily mixes with air and can also form a heavier-than-air cloud on release. This supports combustion and increases the flammability of combustible materials in the immediate vicinity of a release.

NOTE EIGA publication IGC 13/02/E [42] gives guidance on oxygen pipeline practice.

Hydrogen is flammable, lighter than air and easily ignited. When ignited it radiates heat and can produce a vapour cloud explosion.

Methane is flammable, lighter than air, radiates heat on ignition and can form a vapour cloud that can migrate from the point of rupture.

Ethane is flammable, slightly heavier than air, radiates a high heat on ignition and can form a vapour cloud at low level that can migrate from the point of rupture.

C.1.3 Substances conveyed as liquid or gas or in dense phase

Ethylene is flammable, slightly lighter than air but can form a heavier-than-air cloud on release due to temperature reduction. Ethylene radiates a high heat on ignition and can form a vapour cloud that can migrate from the point of rupture. Ethylene has the lowest critical pressure of commonly transported gases, can decompose exothermically and is capable of detonation.

Natural gas liquid (NGL) on release behaves in relation to its constituents, ethane, propane and butane, etc. depending on its particular composition. NGL is flammable, radiates a high heat on ignition and can form a vapour cloud at ground level that can migrate from the point of rupture.

Liquefied petroleum gas (LPG) is flammable and, although conveyed in pipelines as liquid or gas, is released as a heavier-than-air gas (propane and butanes) that can migrate some distance at ground level. LPG radiates a high level of heat on ignition. The behaviour of gases and associated liquids in two-phase flow pipelines depends upon their particular composition on release.

Ammonia is flammable and toxic, and is released as a heavier-than-air gas that can migrate some distance at ground level. Ammonia radiates heat if ignited; the gas has a toxic effect.

Carbon dioxide readily mixes with air but can form a heavier-than-air cloud on release (due to temperature reduction), increasing the risk of asphyxiation in the immediate vicinity. In addition, carbon dioxide has a degree of toxicity (see HSE publication EH 40 [43]).

C.2 External hazards

C.2.1 Fishing

Fishing activity, in particular on-bottom trawling, can cause significant disturbance to the seabed. Trawling equipment such as trawl boards, beams, chains and trawl wires can generate large dynamic loads on exposed or inadequately protected pipelines. This can induce local damage (in the form of coating damage or denting) or global damage (large displacements and buckling) and can also pose significant risk to trawling activities in the event of hooking.

NOTE HSE has issued Guidelines for pipeline operators on pipeline anchor hazards *[44] on its website.*

C.2.2 Anchoring

Anchors deployed from vessels can be either gravity or embedment type. The vessel is secured to the anchor by either chain or wire rope. Anchors are normally designed to penetrate the seabed. During deployment/recovery and in severe weather conditions, anchors can be dragged along the seabed for considerable distances, resulting in severe seabed scarring.

Anchor wires and chains, if laid on top of pipelines, can abrade coatings and damage the pipe.

C.2.3 Dropped objects

Objects can be dropped overside from ships, construction vessels or production facilities. In particular, crane operations involving transfer of equipment and supplies from a vessel to a platform or rig can result in accidental impacts on a pipeline.

Dropped objects can travel a considerable lateral distance through the water plane, dependent on object mass, shape, drop velocity and direction, currents and secondary impacts, such as platform substructures.

C.2.4 Marine vessels

In shallow waters, pipelines can be at risk from grounding marine vessels.

C.2.5 Geotechnical hazards

In areas of high currents and severe wave conditions, the seabed can locally liquefy or fluidize, resulting in a loss of bearing support to a pipeline. This can result in excessive settlement or even flotation and exposure of a previously buried line in the fluidized seabed soils.

Seabed gradients can be disturbed by severe environmental or seismic action resulting in slope failure or mudslides. This can induce large displacements of a pipeline over a relatively short length.

In regions where shallow gas pockets are observed, the release of gas can induce a local depression in the seabed and resulting loss of support to a pipeline.

Pipelines in seismically active regions can be prone to earthquake-induced dynamic forces.

Annex D (normative) Safety evaluation of pipelines

NOTE This annex provides guidelines for the planning, execution and documentation of safety evaluations of pipelines recommended in ***5.4.2****. This annex refers principally to the evaluation of the effect of loss of fluids on public safety. The principles in this annex may, however, also be used for other safety evaluations.*

D.1 General recommendations

Safety evaluations, in the form of risk assessments, should be carried out to demonstrate whether the pipeline is designed, constructed and operated in accordance with the safety recommendations in this part of PD 8010.

NOTE Figure D.1 shows a typical safety evaluation.

Risk assessments should be performed according to the following steps:

- define the extent of the risk assessment (**D.2**);
- identify all credible failure modes (**D.3**);
- evaluate failure frequencies (**D.4**);
- evaluate consequences of failure (**D.5**);
- carry out hazard screening (**D.6**);
- evaluate individual and societal risk levels (**D.7**);
- assess the acceptability/tolerability of the risk levels (**D.8**);
- implement mitigation measures as necessary (**D.9**);
- re-evaluate acceptability (**D.10**);
- document the analysis (**D.11**).

Further safety evaluations should be carried out during the operational life of the pipeline in case of changes to the definition of the pipeline and the pipeline environment or other circumstances that could render the conclusions of the original evaluation invalid.

Safety evaluations should be performed by personnel having the necessary specialist technical and safety expertise.

D.2 Definition of the extent of a risk assessment

The extent of the risk assessment should be defined and formulated to provide the basis for the evaluation plan. This should include:

a) the reason(s) for performing the assessment and case-specific objective(s) and outputs;

b) a collection of relevant and necessary data;

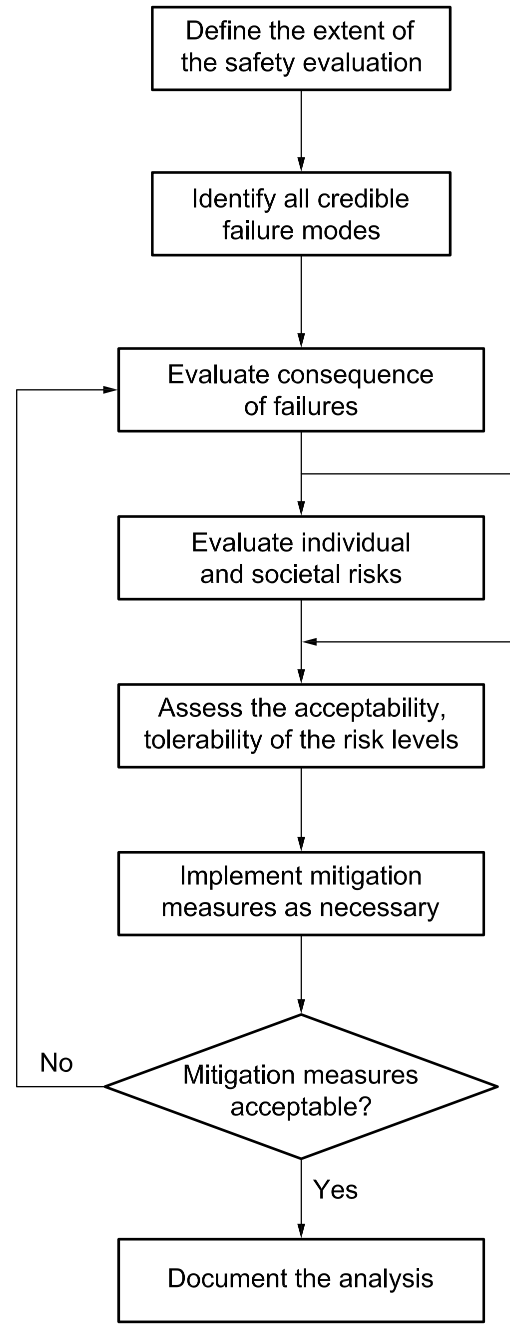
c) a definition of the pipeline, its contents and their properties, methods of operation, maintenance and assurance measures;

d) a definition of the environment, e.g. human habitation and activities near the pipeline; surrounding infrastructure, location, traffic loadings and meteorology;

e) identification of the measures that might be practical and effective in removing or mitigating adverse effects on public safety;

f) a description of assumptions and constraints governing the assessment.

Figure D.1 **Safety evaluation**



D.3 Hazard identification resulting from credible failure modes

The hazard scenarios with the potential to result in a loss of fluid should be identified along the route of the pipeline, together with their root causes (failure modes).

These should include:

a) design, construction or operator error;

b) material or component failure;

c) degradation due to corrosion or erosion, leading to loss of wall thickness;

d) third-party activity (e.g. external damage);

e) natural hazards (e.g. earthquake, flood, lightning, ground movement);

f) fatigue and design life.

NOTE Methods applied for identifying hazards and defining failure modes may include reviews of checklists and historical incident data, brainstorming, and hazard and operability studies.

D.4 Evaluation of failure frequencies

The likelihood of loss of fluid for each of the hazards identified should be estimated by either or both of the following options as appropriate for each hazard:

a) use of relevant historical data (statistical analysis);

NOTE 1 Historical failure rate data can be obtained from company databases, from published data sources such as the United Kingdom Offshore Operators Association (UKOOA) or from the Parloc report [45].

b) predictive methodologies (probabilistic analysis).

NOTE 2 Supporting data for these analyses can be obtained from pipeline damage records.

The mitigation measures assumed when assessing the failure frequencies should also be reported, including proposals for pipeline monitoring and inspection during operation together with emergency procedures.

All such data or record sources should be relevant to the product being transported, the pipeline and its environment, and should not lead to an underestimate of the failure frequency.

Some or all of the following modes of failure should be taken into account, as appropriate for each pipeline:

- full bore rupture;
- large holes;
- minor holes;
- pinhole leaks.

D.5 Evaluation of the consequences of failure

Estimating the likely impact of a loss of fluid should take into account:

a) the nature of the fluid (e.g. flammable, toxic, reactive);

b) pipeline design;

c) buried or above-ground topography;

d) environmental conditions;

e) likely size of hole or rupture;

f) mitigating measures to restrict loss of containment (e.g. leak detection and use of isolation valves);

g) the mode of escape of fluids (e.g. vertical plume, impacted jet, free jet horizontal plume);

h) dispersion of fluid and probability of ignition (fireball, bleve, local fire, pool fire, or other resultant phenomena);

i) possible accident scenarios following a fluid loss, which can include:

1) pressure waves following fluid release;

2) combustion/explosion following ignition;

3) toxic effects or asphyxiations;

4) extended run off field;

5) dispersal resulting in contamination or pollution;

j) level of exposure and estimated effect;

k) the operating parameters of the pipeline;

l) pressure control and emergency shutdown systems;

m) monitoring and communications systems.

NOTE The aim is to construct an event tree, which defines overall frequencies of occurrence for each failure mode, location and type of release.

D.6 Hazard screening

An initial assessment of the significance of the identified hazards should be carried out based on the failure frequency and estimation of possible consequences.

This step of the evaluation should result in one of the following courses of action for each of the identified hazards:

a) curtailment of the assessment because the failure frequency or consequences of the hazard are insignificant;

b) continuation with the detailed evaluation of the risk level.

D.7 Evaluation of individual and societal risk level

The risk level should be determined for:

a) any individuals who might be present along the route of the pipeline ("individual risk"); and

b) if appropriate, any large groups of people that might be present along the route ("societal risk"). The risk level should include contributions from all credible hazards or failure mode.

NOTE Further information is given in HSE publication Reducing risk, protecting people *[46].*

D.8 Assessment of acceptability/tolerability of the risk levels

The results of the risk assessment should be compared with the following HSE risk criteria, and if the level of risk is found to be unacceptable, mitigating measures should be taken.

a) **Individual risk**. In the UK, the HSE criteria for the tolerability of individual risk are divided into three broad categories:

- broadly acceptable;
- tolerable;
- unacceptable.

The "broadly acceptable" category covers individual risk levels that might be considered insignificant, for which no further mitigation is required to reduce the risk further. As a guideline in the UK, this category covers an individual risk of death below one in a million (10^{-6}) per annum (see HSE publication *Reducing risk, protecting people* [46].

The "tolerable" category requires that mitigation measures be employed to drive the risk levels down to the "broadly acceptable" category. A risk is deemed to be tolerable once further risk reduction is impracticable or requires action that is disproportionate to the risk reduced (i.e. the risk is "as low as reasonably practicable" or ALARP). In the UK, the HSE has proposed an individual risk of death of one in ten thousand (10^{-4}) per annum as the upper boundary of what might be considered tolerable (see HSE publication *Reducing risk, protecting people* [46]). However, this level of individual risk is also likely to give rise to societal concerns and these can play a greater role in determining the acceptability of a risk.

The "unacceptable" category covers risks that are unacceptable whatever the benefits. Mitigation would be required to reduce the level of risk.

b) **Societal risks**. Societal risk criteria recognize the need to ensure that major incidents that could lead to a significant number of casualties in a single event occur far less frequently than those that could lead to an individual casualty.

In the UK, the most common form of representing societal risk is known as the *F–N* approach. The *F–N* approach expresses and manages the risk in terms of the frequency, *F*, of *N* or more casualties occurring. The HSE has not published an agreed *F–N* criterion; however, they propose that the risk of an accident causing the death of fifty people or more in a single event should be less than one in five thousand per annum (see HSE publication *Reducing risk, protecting people* [46]).

An acceptable *F–N* criterion can also be derived from knowledge of the risk levels that are implicit on existing pipeline systems.

D.9 Implementation of mitigation measures

The aim of the incorporation of mitigation measures should be to reduce the unacceptable calculated levels to be as low as reasonably practicable (ALARP).

NOTE Additional measures of pipeline protection can be necessary to prevent damage arising from unusual conditions, or due to exceptional loads, long self-supported spans, vibration, mass of special attachments, ground movement, abnormal corrosive conditions and any other abnormal forces. Typical examples of extra protection are:

a) increased pipe wall thickness;

b) additional protection above the pipe;

c) application of concrete or similar protective coating to the pipe;

d) use of thicker coatings to improve corrosion protection;

e) burial or increased depth of cover;

f) provision of impact protection for exposed pipelines.

The residual risk level following the adoption of additional mitigation measures should be assessed (see **D.8**).

D.10 Re-evaluation of acceptability

Where mitigation measures have changed the initial failure modes, the consequence and risk analyses should be re-evaluated for conformity to the ALARP principle. An assessment should be performed which demonstrates that all reasonably practicable measures to reduce risk have been included. Where specific areas are found not to conform, those areas should be reappraised and further mitigation measures put in place until all conform.

D.11 Documentation of the analysis

The safety evaluation should be documented and the documentation should include as a minimum:

a) table of contents;

b) summary;

c) objectives and extent of the evaluation;

d) safety requirements;

e) limitations, assumptions and justification of hypotheses;

f) description of system;

g) clear map of pipeline and plans illustrating all infrastructure on route;

h) analysis methodology, including software used;

i) hazard identification results;

j) models description with assumptions and validation;

k) data and their sources;

l) risk assessments performed;

m) effect on public safety;

n) sensitivity and uncertainties;

o) discussion of results;

p) conclusions;

q) references.

This report should be maintained for the life of the pipeline.

Annex E (normative) Pipeline route selection

E.1 General

Route selection should take into account the design, construction, operation, maintenance and abandonment of the pipeline.

To minimize the possibility of future corrective work and limitations, anticipated developments and future exploration should be taken into account.

Factors which should be taken into account during route selection include:

a) safety of the public (see **5.4** and Annex D) and personnel working on or near the pipeline;

b) contents of the pipeline and operating conditions;

c) protection of the environment (see **E.2**);

d) other property and facilities (see **E.3**);

e) third-party activities (see **E.4**);

f) geotechnical, corrosivity and hydrographical conditions (see **E.5**);

g) construction, operation and maintenance;

h) national and/or local planning restrictions;

i) future exploration;

j) surveys (see **E.6**);

k) any other hazards.

E.2 Environment

An assessment of environmental impact should take into account:

a) temporary works during construction, repair and modification;

b) the long-term presence of the pipeline (see also Clause **14**);

c) potential loss of fluids.

E.3 Other facilities

Facilities along the pipeline route that can affect the pipeline should be identified and their impact evaluated in consultation with the operator of these facilities.

E.4 Third-party activities

Third-party activities along the route should be identified and should be evaluated in consultation with these parties.

E.5 Geotechnical, hydrographical and meteorological conditions

Adverse geotechnical, meteorological and hydrographical conditions should be identified and mitigating measures defined. Meteorological conditions should be reviewed in all cases.

E.6 Surveys

Data should be collected by hydrographic survey of the proposed route prior to final selection of the pipeline corridor.

This survey should include investigation of:

a) seabed geology and features;

b) bathymetry;

c) environmental and oceanographic data;

d) wellheads, wrecks and debris;

e) marine growth;

f) landfall;

g) the presence of ordnance or other hazardous items.

The following should be taken into account when selecting the route:

1) type and intensity of shipping and the presence of anchoring zones;

2) type and intensity of fishing activity;

3) presence of fishing grounds and other sensitive areas;

4) presence of other pipelines, installations or wellheads;

5) presence of wrecks or other obstructions;

6) presence of regularly dredged areas and dumping grounds;

7) operators whose blocks are crossed by the pipeline;

8) presence of submarine cables;

9) designated dangerous zones;

10) sediment transport;

11) sediment types;
12) seabed instability;
13) installation limitations;
14) connections to existing facilities;
15) seabed currents.

When a landfall is involved, information should be obtained concerning:

i) waves;
ii) tides;
iii) scour;
iv) coast erosion;
v) beach movement;
vi) topography;
vii) geology;
viii) environmental sensitivity.

Annex F (normative) Loads

F.1 Types of load

Loads that can cause or contribute to pipeline failure or loss of serviceability of the pipeline system should be identified and accounted for in the design.
The following types of load should be taken into account:

a) self-weight (including weight of steel, coatings, attachments, contents and marine growth);
b) external hydrostatic pressure;
c) buoyancy effects;
d) internal fluid loads, e.g. pressure, inertial effects;
e) installation forces (such as reeling loads, tow loads, applied lay tension, and trenching forces);
f) loads due to changes of pressure and temperature;
g) environmental loads;
h) seabed stability settlement and platform movement;
i) loads arising from fishing and other activities and dropped objects near platforms;
j) residual loads.

Residual loads should be taken into account in all cases where they could adversely affect the pipeline. Where these loads cannot be accurately established, a conservative estimate should be made of their values.

*NOTE See also **7.6** for possible causes of damage and possible protection methods.*

F.2 Loading conditions

The following loading conditions should be taken into account:

a) construction loads (**F.3**);
b) hydrostatic testing (**F.4**);

c) functional loads (**F.5**);

d) functional and environmental loads (**F.6**);

e) functional plus predictable accidental loads, which can be reasonably accommodated (**F.7**).

The loads making up each loading condition should be in the combinations that can be expected to pose the greatest threat to the safety of the pipeline.

F.3 Construction loads

NOTE Construction loads include all loads (except any intermediate hydrostatic testing) to which the pipeline system is subjected prior to its final hydrotest. These loads include those arising from:

a) fabrication of pipe strings;

b) installation;

c) tie-ins;

d) any repair for which the system is decommissioned;

e) environmental forces;

f) pipe stacking.

Where environmental loading is taken into account, the applied loading that poses the greatest threat to the safety of the pipeline likely to be encountered during the construction phase should be selected.

F.4 Hydrostatic testing

An analysis should be performed to ensure that the pipeline and its supports can accommodate the loads that occur during hydrostatic testing.

NOTE These include the effects of the weight of contents and of pipeline expansion.

F.5 Functional loads

F.5.1 Classification

Loading conditions that should be classified as functional loads include:

a) weight of the pipeline system and its contents;

b) thermal effects;

c) pressure effects;

d) transient operational effects;

e) hydrostatic pressure of the environment;

f) residual installation load remaining after hydrotest.

F.5.2 Temperature

The range in fluid temperatures during normal operations and anticipated blowdown conditions should be taken into account when determining temperature-induced loads.

F.6 Functional and environmental loads

NOTE Environmental loads can be due to wind, waves, currents, earthquakes and other environmental phenomena.

Combinations of environmental and functional loads should be selected on the basis of the likelihood of simultaneous occurrence.

Whilst loads associated with a storm (e.g. wind and waves) should be taken into account together, it is not necessary to combine independent extreme environmental loads (e.g. storm and earthquake) in a single load case.

Environmental loads should be determined in accordance with Annex H or with an alternative approach that can be shown to give equivalent results.

F.7 Functional plus accidental loads

Accidental loads should be taken into account in combination with the least favourable functional loads. Accidental loads should be calculated in relation to their likely frequency of occurrence.

NOTE It is not necessary to take into account combinations of accidental loads, or accidental loads in combination with extreme environmental loads, unless they can be reasonably expected to occur together.

Annex G (informative) Buckling

G.1 Local buckling

G.1.1 General

NOTE 1 Local buckling of the pipe wall can be avoided if the various loads to which the pipe is subjected are less than the characteristic values in ***G.1.2*** *to* ***G.1.7****.*

NOTE 2 Guidance on buckling is given in DNV-OS-F101.

Where the concrete cladding is thick enough and reinforced to provide a structural member conforming to BS 6349-1-4 and BS EN 1992-1-1, it may be used to provide support against buckling provided that appropriate justification is given.

G.1.2 External pressure

The characteristic external pressure, P_c, that causes collapse when the external pressure is acting alone, can be calculated using equations (G.1) to (G.4).

$$\left\{\left(\frac{P}{P_e}\right)-1\right\}\left\{\left(\frac{P_c}{P_y}\right)^2-1\right\}=\frac{P_c}{P_y}\left(f_o\frac{D_o}{t_{nom}}\right) \quad (G.1)$$

$$P_e=\frac{2E}{\left(1-\nu^2\right)}\left(\frac{t_{nom}}{D_o}\right) \quad (G.2)$$

$$P_y=2\sigma_y\frac{t_{nom}}{D_o} \quad (G.3)$$

$$f_o=\frac{D_{max}-D_{min}}{D_o} \quad (G.4)$$

NOTE See also Ultimate pipe strength under bending, collapse and fatigue *[47].*

G.1.3 Axial compression

If D/t_{nom} is less than 60, local buckling under axial compression does not occur until the mean axial compression load, F_{xc}, reaches the yield load, F_y, i.e. as shown in equation (G.5).

$$F_{xc}=F_y=\pi\left(D_o-t_{nom}\right)t_{nom}\sigma_y \quad (G.5)$$

G.1.4 Bending

The characteristic bending moment, M_c, required to cause buckling when bending moments are acting alone, can be obtained using equations (G.6) and (G.7).

$$\frac{M_c}{M_p} = 1 - 0.0024\frac{D_o}{t_{nom}} \qquad (G.6)$$

$$M_p = (D_o - t_{nom})^2 t_{nom}\sigma_y \qquad (G.7)$$

The characteristic bending strain, ε_{bc}, at which buckling due to bending moments acting alone occurs, can be obtained using equation (G.8).

$$\varepsilon_{bc} = 15\left(\frac{t_{nom}}{D_o}\right) \qquad (G.8)$$

G.1.5 Torsion

The characteristic value, τ_c, that causes buckling when torsion is acting alone, can be obtained using equations (G.9) to (G.13).

Equation (G.9) is used when $\alpha_\tau < 1.5$; equation (G.10) is used when α_τ is ≥ 1.5 and ≤ 9; and equation (G.11) is used when $\alpha_\tau > 9$.

$$\tau_c/\tau_y = 0.542 \times \alpha_\tau \qquad (G.9)$$

$$\tau_c/\tau_y = 0.813 + 0.068(\alpha_\tau - 1.5)^{0.5} \qquad (G.10)$$

$$\tau_c/\tau_y = 1 \qquad (G.11)$$

$$\tau_y = \frac{\sigma_y}{3^{0.5}} \qquad (G.12)$$

$$\alpha_\tau = \frac{E}{\tau_y}\left(\frac{t_{nom}}{D_o}\right)^{3/2} \qquad (G.13)$$

G.1.6 Load combinations

The maximum external overpressure, P, in the presence of compressive axial force, F_x, and/or bending moment, M, when f_o is less than 0.05 (5%), can be calculated using equation (G.14), where:

- γ is calculated using equation (G.15);
- σ_{hb} is calculated using equation (G.16);
- σ_{hcr} is calculated using equation (G.17) or equation (G.18) as appropriate.

$$\{(M/M_c) + (F_x/F_{xc})\}^\gamma + (P/P_c) = 1 \qquad (G.14)$$

$$\gamma = 1 + 300 \times \frac{t_{nom}}{D_o} \times \frac{\sigma_{hb}}{\sigma_{hcr}} \qquad (G.15)$$

$$\sigma_{hb} = \frac{P \times D_o}{2t_{nom}} \qquad (G.16)$$

$$\sigma_{hcr} = \sigma_{hE} = E\left(\frac{t_{nom}}{D_o - t_{nom}}\right)^2 \quad \text{for} \quad \sigma_{hE} \leq \frac{2}{3}\sigma_y \qquad (G.17)$$

$$\sigma_{hcr} = \sigma_y\left\{1 - \left(\frac{1}{3}\right) \times \left(\frac{2\sigma_y}{3\sigma_{hE}}\right)^2\right\} \quad \text{for} \quad \sigma_{hE} > \frac{2}{3}\sigma_y \qquad (G.18)$$

Values for P_c, F_{xc} and M_c can be obtained from equations (G.1), (G.5), (G.6) and (G.7) respectively.

G.1.7 Strain criteria

The bending strain, ε_b, required to cause buckling, in the presence of external overpressure, P, can be calculated using equation (G.19).

$$\frac{\varepsilon_b}{\varepsilon_{bc}} + \frac{P}{P_c} = 1 \tag{G.19}$$

Values for ε_{bc} and P_c can be obtained from equations (G.8) and (G.1) respectively.

G.2 Propagation buckling

The potential for a pipeline to propagate local buckles is dependent on the external overpressure, P, and its relationship with the propagation pressure, P_p.

The external overpressure, P, can be calculated using equation (G.20).

$$P = P_o - P_i \tag{G.20}$$

The propagation pressure, P_p, can be calculated using equation (G.21).

$$P_p = 10.7\sigma_y\left(t_{nom}/D_o\right)^{2.25} \tag{G.21}$$

If P is less than P_p, then, even though it is possible for the pipe to develop a local buckle, the buckle will not propagate.

If P is greater than or equal to P_p and a local buckle or local damage has occurred, then the pipeline is likely to undergo propagation buckling. It can be advisable to provide buckle arresters at strategic locations along the pipeline to limit the amount of pipeline damaged by a propagated buckle.

G.3 Upheaval buckling

Two major factors contribute towards the upheaval of subsea pipelines: the effective axial driving force, arising from the internal pressure and temperature, and the presence of vertical out-of-straightness (OOS) in the seabed profile. The resistance to upheaval is provided by the submerged weight of the pipeline, plus any overburden, if present. The effects of the various parameters may be gauged by calculating the equilibrium of the system at the point of instability (see *Upheaval buckling: what we know and what we don't know* [48]). It is instructive to examine the upheaval phenomena in terms of the dimensionless coefficients defined in *The effect of imperfection shape on upheaval behaviour* [49].

A typical imperfection is defined in terms of a characteristic length, L_c, and an imperfection height, H_c.

The download coefficient, Φ_w, is calculated using equation (G.22).

$$\Phi_w = \frac{\omega E \times I}{H_c P_{eff}^2} \tag{G.22}$$

Similarly, the imperfection length may be characterized by a dimensionless coefficient using equation (G.23).

$$\Phi_L = L_c\left(\frac{P_{eff}}{E \times I}\right)^{0.5} \tag{G.23}$$

It can be shown, from either numerical or experimental test results, that there exists a functional relationship of the form given in equation (G.24).

$$f\left(\Phi_w, \Phi_L\right) = 0 \tag{G.24}$$

The functional relationship shown in equation (G.24) may be used to assess the overburden requirement to prevent upheaval buckling of the pipeline.

The following issues need to be taken into account when determining the overburden requirement:

a) spacing of the vertical profile data;

b) uplift resistance of the backfill, remoulded clay, backfilled sand, etc.

The stress/strain level along the pipeline needs to be within allowable limits and remedial work needs to be carried out where these limits are exceeded.

G.4 Ovalization

The total ovalization, *f*, of a pipe due to the combined effects of unidirectional bending and external pressure can be calculated using equations (G.25) to (G.27).

$$f = C_p \left\{ C_f \left(\frac{D_o}{t_{nom}} \varepsilon_b \right)^2 + f_o \right\} \quad (G.25)$$

$$C_p = 1/(1 - P/P_e) \quad (G.26)$$

$$C_f = 0.12\{1 + D_o/(120 t_{nom})\} \quad (G.27)$$

Values for P_e and f_o can be obtained from equations (G.2) and (G.4) respectively.

NOTE If cyclic or reversed bending is applied, the resulting ovalization can be considerably greater than that predicted by the equation.

Annex H (normative) Environmental considerations

H.1 Environmental factors

H.1.1 General

The design of a subsea pipeline system is fundamentally dependent upon the loads and influences imposed by the natural environment. In designing the pipeline system to withstand both extreme and long-term environmental effects, the following should be determined:

a) description of the characteristics of the natural environment in terms of defined and quantifiable parameters;

b) evaluation of the influence of these parameters upon the pipeline system.

NOTE Owing to the random element inherent in natural processes, statistical definitions and statistical analysis of measured data are important in defining many environmental parameters.

H.1.2 Return periods

The design return periods corresponding to the operational phase and construction phase should be specified.

The design return period for the normal operational phase should be not less than three times the design life or 100 years, whichever is the shorter, unless otherwise justified.

NOTE Elaboration on design life, risk and return period is given in BS 6349-1-1.

For the construction phase (see **F.3**), the design return period should be selected to take account of the expected duration of that phase and the consequences of exceeding the design conditions.

In selecting values for design, the combined probability of the various extreme conditions should be addressed on either a probabilistic or a deterministic approach.

H.1.3 Water depths

Water depths along the pipeline route should be referred to a consistent datum.

NOTE Elevation relative to either offshore chart or land-based ordnance datum is acceptable.

Water depth variation due to the following should be taken into account:

a) astronomical tidal ranges;

b) surface waves;

c) wind and pressure-induced storm surge effects;

d) geostatic and climate changes.

These should be combined, taking account of the probability of their simultaneous occurrence, to give the most severe design water depth for each of the load cases given in **F.2**.

H.1.4 Wind

For exposed sections of a pipeline system, the design wind speed used in determining wind loads should be the 3 s gust speed corresponding to the design return period (see **H.1.2**). Variation of the gust wind speed with height should also be taken into account.

Wind should be assumed to be omnidirectional, unless directional statistics are available.

Where there is no specific wind data available, design wind speeds should be calculated according to the method given in BS EN 1991-1-4.

H.1.5 Waves

H.1.5.1 General

Information on ocean waves should be gathered to determine:

a) extreme environmental loading;

b) long-term fatigue loading;

c) installation activities and associated loadings;

d) operational activities and associated loadings.

NOTE Owing to the random characteristics of ocean wave behaviour, many aspects of the wave can only be expressed in statistical terms and evaluated by a statistical analysis obtained from measurements, observations or numerical models.

Waves should be assumed to be omnidirectional unless directional statistics are available.

H.1.5.2 Wave parameters

The following wave parameters should be taken into account.

a) **Design sea state**. The design sea state is the sea state expected to be equalled or exceeded once within the design return period. Natural waves are most often described by their significant wave height, H_s, and their mean period, T_m. In the past a significant wave period, T_S, has often been used. The inequality relationship is $T_m < T_S < T_p$.

b) **Significant wave height**. The significant wave height is the average height of the highest one-third of the waves and has been found to approximate to the visual estimate of wave height that would be obtained from an experienced observer.

The significant wave height, H_s, may be taken as equivalent to H_{m0}, where H_{m0} is calculated using equation (H.1).

$$H_{m0} = 4(m_0)^{0.5} \quad (H.1)$$

c) **Mean wave period**. The mean wave period, T_m, is similar to the zero-crossing wave period, T_z, which is the average period of all the waves with troughs below and crests above mean water level. T_m is calculated using equation (H.2).

$$T_z \approx T_m = \left(\frac{m_0}{m_2}\right)^{0.5} \quad (H.2)$$

For storm waves the wave gradient, in terms of significant wave height and deep water wave length, $H_s/L_0 = 2\pi H_s/(gT_z{}^2)$, is typically in the range 0.04 to 0.06. For a fully developed sea state it can be taken to be 0.05 irrespective of the wave height. For outline design this gives an approximate relationship as shown in equation (H.3).

$$T_z = 11(H_s/g)^{0.5} \quad (H.3)$$

A sensitivity analysis should be made and fuller analysis should be undertaken where necessary for detail design.

d) **Maximum wave height**. The maximum wave height, H_{max}, is the trough-to-crest height of the single wave that is expected to be equalled or exceeded once within the design return period.

e) **Peak wave period**. The periods associated with maximum wave heights can be expected to be close to the period, T_p, at which the peak occurs in the one-dimensional frequency spectrum. The values of T_p are theoretically as follows:

- T_p= 1.28T_z for JONSWAP spectrum;
- T_p = 1.40T_z for Pierson–Moskowitz spectrum.

For storm waves, the JONSWAP spectrum should be used for fetch limited situations and the Pierson–Moskowitz spectrum for the fully developed sea.

NOTE 1 In physical terms, the maximum wave characterizes the worst case individual wave, whilst the significant wave more closely characterizes the mean energy within the sea state as a whole.

NOTE 2 Further information is given in BS 6349-1-1 and Dynamics of marine sands – A manual for practical applications *[50].*

H.1.5.3 Extreme environmental loading

The maximum wave corresponding to the design return period should generally be taken to define the extreme environmental wave loading.

NOTE Exceptions may be made in cases where infrequent, transient, localized loading is not likely to present a risk of failure. The significant wave or a spectral approach can be a more appropriate description of extreme conditions in such cases.

H.1.5.4 Long-term fatigue loading

For the determination of fatigue loading, the following should be taken into account:

a) distribution of energy within the wave spectrum for a given sea state;

b) distribution of sea states throughout the design lifetime of the installation.

H.1.5.5 Installation activities and associated loadings

For the planning of installation activities, the following statistical information should be obtained:

a) total percentage occurrence of sea states lying within the operational limits for the various installation activities;

b) duration of uninterrupted sea states lying within the operational limits for the various installation activities.

H.1.5.6 Operational activities and associated loadings

If the future operation of the pipeline is dependent upon weather-sensitive activities, then the feasibility of performing operational activities should be assessed at the design stage. For the planning of such activities, the same statistical information should be obtained as for installation activities (see **H.1.5.5**).

H.1.5.7 Shallow water effects

In nearshore areas and shoaling water, the seabed bathymetry and shoreline configuration can have a significant influence on the wave characteristics. Effects that should be taken into account include:

a) refraction;

b) shoaling;

c) breaking;

d) diffraction;

e) reflection;

f) absorption;

g) longshore currents (see **H.1.6**).

If specific local data is not available, the changes in the wave characteristics should be calculated for the full range of water levels expected at the site.

NOTE Changes in wave characteristics can be determined by the application of a variety of theories.

H.1.5.8 Wave-induced water particle motion

Water particle displacement, velocity and acceleration should be determined from the basic wave height, period data and water depth by applying an appropriate wave theory. The following effects should be taken into account when determining a suitable wave theory:

a) relationship between wave height, wave length and water depth;

b) possibility of wave breaking;

c) location(s) within the wave where information is required.

Approximate forms of wave theories should be used only with great care.

NOTE For example, the deep water approximation to linear wave theory can result in significant errors when used to predict velocities close to the seabed.

H.1.6 Currents

Design currents should be determined from statistical analysis of recorded data (assuming these are of sufficient duration) in combination with numerical model simulations.

Design current velocities should include the contributions from all significant constituent components, including:

a) tidal;

b) wind-induced;

c) storm surge;

d) ocean circulations;

e) density currents;

f) river discharge;

g) longshore currents.

The components should be combined, taking account of the probability of their simultaneous occurrence for each load case assessed.

The current velocity and direction should be determined for the selected return periods (see **H.1.2**). Where no directional data is available, it should be assumed that the direction of the design current is normal to the pipeline.

The variation of current velocity with water depth and adjacent structures should be taken into account.

In the case of two risers or a riser adjacent to a jacket leg, the water velocity amplification, V_i, of one due to the proximity of the other is generally calculated using equation (H.4).

$$V_\mathrm{i} = V_\mathrm{u}\left(1 + \frac{R^2}{z^2}\right) \tag{H.4}$$

NOTE Detailed analysis can be necessary when more than two risers are in close proximity and to take account of amplification of wave-induced velocities.

H.1.7 Air and sea temperatures

The maximum and minimum air and sea temperatures that are likely to be encountered during the design life of the pipeline system should be established. Possible differences in sea temperature between the surface and the seabed should be taken into account.

Appropriate ambient temperatures should be included in the design to ensure that suitable temperature differentials are always applied.

H.1.8 Marine growth

Marine growth can increase the cross-sectional area and alter the surface characteristics of a pipe. These effects should be taken into account when designing the pipeline system.

The expected extent of marine growth should be established and applied in the design analysis. Once the pipeline system is in place, the extent of marine growth should be monitored and the design revalidated if the design thickness is exceeded.

NOTE The report Appraisal of marine fouling on offshore structures *[51] provides guidance in determining the likely extent of marine growth for particular areas. The Department of Energy publication* Offshore installations – Guidance of design, construction and certification *[52] and BS 6349-1-1 give additional guidance.*

In performing the design analysis, account should be taken of the effects of marine growth in relation to:

a) increased diameter;
b) increased drag coefficient;
c) increased mass;
d) increased hydrodynamic added mass;
e) effect on inspection programmes;
f) corrosion implications.

H.1.9 Seabed soils

The following seabed soil information should be obtained:

a) soil type;
b) grain size distribution;
c) presence and size of boulders;
d) shear strength, angle of internal friction and cohesion;
e) water content;
f) liquid and plastic limits;
g) bulk density (including maximum and minimum values);
h) oxygen content, salinity and organic content;
i) presence of hydrogen sulfide, producing bacteria;
j) electrical resistivity;
k) thermal conductivity;
l) historical records of bed movement and storm effects.

Seabed soil information should be used to evaluate:

1) seabed friction;
2) seabed bearing capacity;
3) scour and spanning potential;
4) movement of sandwaves and other bedforms;
5) natural backfill potential;
6) self-burial potential;
7) liquefaction;
8) flotation;
9) slope stability;
10) corrosion and cathodic protection;
11) heat loss from buried lines.

H.1.10 Seismic activity

The possibility of seismic activity on or near the pipeline system should be evaluated. The amplitude, velocity and acceleration of ground movement should be determined and the response of the pipeline system assessed.

Seismically-induced shock pressure waves in the surrounding seawater and the possibility of soil liquefaction should also be evaluated.

H.2 Environmental loads

H.2.1 General

The environmental factors described in **H.1** impose a range of influences upon a pipeline system. Their combined influence should be evaluated by superimposing component effects, taking into account the probability of their simultaneous occurrence.

Directional effects should be taken into account where relevant. Where there is insufficient directional data available, loads should be applied to the pipeline system from the direction, or combination of directions, that produces the most severe condition.

H.2.2 Hydrostatic loading

When determining the hydrostatic load for a given design aspect, the water depth selected should lead to the most severe loading condition (see **H.1.3**). The effect of surface waves should be taken into account.

H.2.3 Wind loads

NOTE Wind loads acting on a pipe produce two effects:

a) direct static loads, which are assumed to act normal to the pipe;

*b) vortex shedding (see **H.2.5**), caused by unsteady flow patterns around the pipe.*

The static wind load should be determined in accordance with BS EN 1991-1-4.

The total outside diameter of the pipe should include all coatings plus any additional accumulations on the pipe surface such as marine growth and ice.

H.2.4 Hydrodynamic loads

H.2.4.1 General

Hydrodynamic loads should include:

a) direct hydrodynamic loads (see **H.2.4.2**);

b) wave slam (see **H.2.4.3**);

c) shock pressure from breaking waves (see **H.2.4.4**).

H.2.4.2 Direct hydrodynamic loads

Direct hydrodynamic loads are the result of water particle flow around the pipe from both current and wave effects. These loads should include:

a) drag force (F_D);

b) inertia force (F_I);

c) lift force (F_L).

NOTE 1 There are two principal calculation approaches for the determination of wave loads.

- *Deterministic approach, in which the properties of a sea state are characterized by a statistically derived design wave. The water particle motions induced by the design wave are calculated using an appropriate wave theory (see **H.1.5.8**). Hydrodynamic loads corresponding to the design wave are then calculated.*
- *Statistical approach, in which the properties of a sea state are described in terms of spectral distribution. Using appropriate wave theory, corresponding spectral distributions of wave-induced water particle motion are developed, from which a resulting force distribution is derived.*

NOTE 2 See Mechanics of wave forces on offshore structures *[53] for details of this type of approach. Practical application of a statistical approach requires the use of specialized computer software.*

For a given water particle velocity and acceleration, the direct hydrodynamic loads per unit length of the pipeline should be calculated using equations (H.5) to (H.7).

$$F_D = \frac{1}{2}\rho C_D D u \left| u \right| \tag{H.5}$$

$$F_L = \frac{1}{2}\rho C_L D u^2 \tag{H.6}$$

$$F_I = \frac{1}{4}\rho C_M \alpha \pi D^2 \tag{H.7}$$

Unless a more precise method is used, wave-induced water particle velocity components should be combined with steady current (see **H.1.6**) components by vectorial addition. All velocity components should be combined before calculating the hydrodynamic forces.

NOTE 3 Wave-induced water particle motion is dependent upon the phase angle of the wave. Phase differences exist between the following parameters:

- *velocity and acceleration components;*
- *horizontal and vertical flow components.*

The phase angle should be selected to give the worst case vectorial combination of force components.

NOTE 4 Values of the hydrodynamic force coefficients, C_D, C_M, and C_L are dependent upon the following:

- *Reynolds number;*
- *Keulegan Carpenter number;*
- *relative surface roughness of the pipeline;*
- *separation distance of the pipeline from a solid boundary;*
- *degree of embedment of the pipeline;*
- *relative magnitudes of wave-induced and steady current water particle velocity components.*

If the pipe is adjacent to another structure or forms one of a number of closely spaced pipes, account should be taken of possible interaction and solidification effects. Where the adjacent structure is relatively large, such as a concrete platform or a jacket leg, account should also be taken of the effect of increased particle velocities and accelerations resulting from the modified flow regime.

Care should be taken when selecting hydrodynamic coefficients to ensure that all assumptions are compatible and the calculations carried out follow one consistent logical course.

NOTE 5 DNV-OS-F101 and DNV-RP-F109 have been found to offer reliable advice with regard to methods of analysis and the selection of hydrodynamic coefficients.

H.2.4.3 Wave slam

NOTE A horizontal length of pipe in the splash zone can experience wave-slamming forces caused by sudden immersion of the pipe during the passage of a wave.

The slamming force, F_W, per unit length in the direction of the velocity should be calculated using equation (H.8).

$$F_W = \frac{1}{2}\rho C_s D u_s^2 \tag{H.8}$$

where the slamming coefficient, C_s, should be taken as not less than 3.0 for smooth circular cylinders.

Dynamic amplification should also be taken into account when determining the response stresses. For a pipe fixed at both ends, the following dynamic amplification factors should be used:

a) end moments: 1.5;

b) midspan moment: 2.0.

The fatigue damage due to wave slamming should also be taken into account and added to the fatigue contribution from other variable loads.

H.2.4.4 Shock pressure from breaking waves

NOTE Shock pressure is a local pressure on the face of the pipe, produced when the breaking wave meets a pipe.

Unless more precise data is available, the force should be calculated using equation (H.8) where:

a) slamming coefficient C_S is 3.0;

b) width is equal to a sector ±22.5°; measured from the wave direction (see Figure H.1);

c) height is equal to $H_B/4$ (see Figure H.1).

The impact velocity should be calculated as the maximum velocity in the breaking wave.

The force from the breaking wave should be applied between the still water level and the wave crest to give the most critical loading.

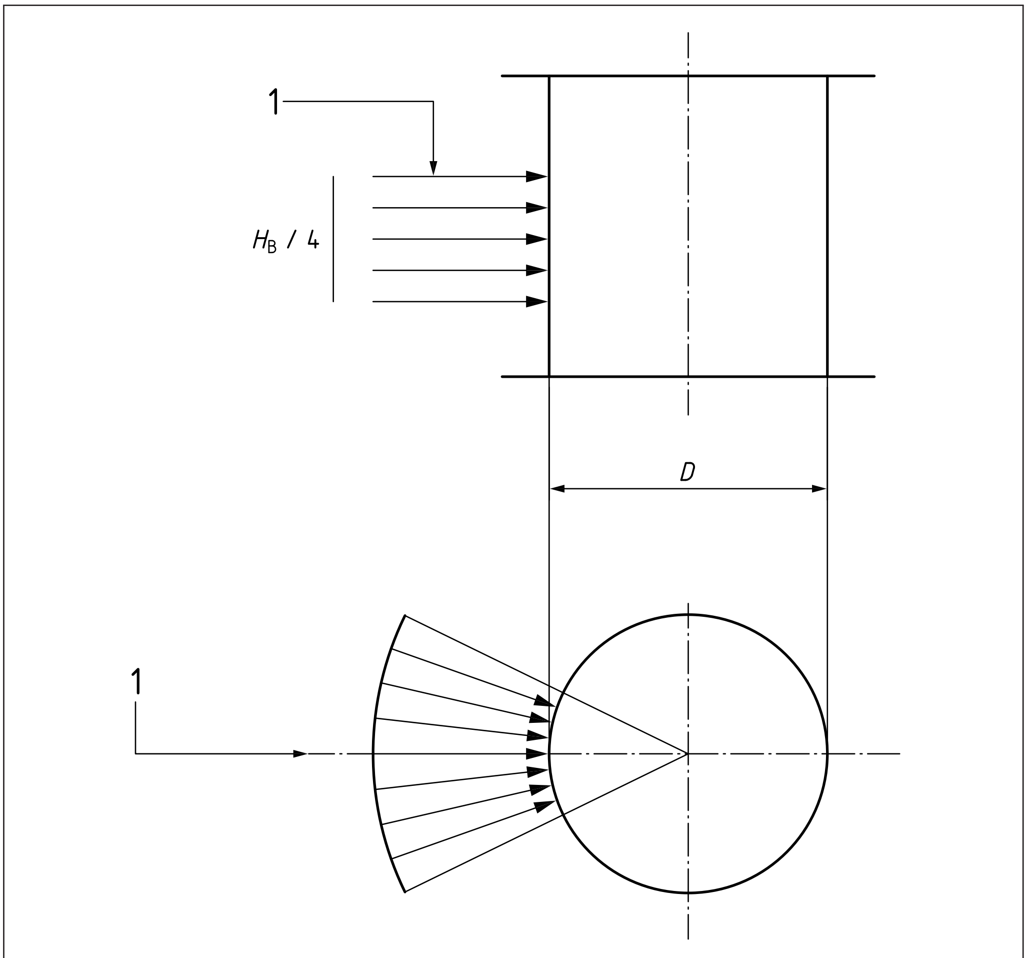
H.2.5 Flow-induced cyclic loads

NOTE 1 Fluid flow past unsupported pipeline or riser spans can cause fluctuating pressure forces due to vortex shedding, which can lead to resonant vibrations of the pipe.

Vortex-induced span vibration is of principal concern for submarine sections of the pipeline system, but the possibility of wind-induced vibration of exposed riser spans should also be taken into account.

NOTE 2 For the evaluation of wind-induced vibration of exposed riser spans, see ESDU No. 78006 [54].

Figure H.1 **Area to be investigated when calculating the shock pressure**



Key

1 Shock pressure

H.2.6 Platform movement

NOTE Platform movements impose loadings on risers and adjacent sections of pipeline.

Sources of platform movement that should be taken into account include:

a) elastic movement of fixed and floating platforms due to wave, current and wind effects;

b) immediate soil deformation due to installation of a fixed platform;

c) long-term soil settlement under and around a fixed platform.

Elastic platform movement should be determined under the design storm conditions.

H.2.7 Soil-related effects

H.2.7.1 General

Parameters used in design should be determined from a soil survey (see **H.1.9**).

H.2.7.2 Resistance to movement

NOTE 1 The resistance of a pipeline to movement over the seabed has a number of important design implications, including:

a) pipeline stability;

b) pipeline expansion movement;

c) installation by pull or on-bottom tow methods.

The design procedure should take into account all relevant aspects and determine an appropriate theory for seabed resistance calculation.

NOTE 2 It is a commonly accepted practice to express the soil resistance force as the product of the coefficient of soil friction and submerged weight. However, this approach generally represents an empirical simplification rather than an accurate description of the physical pipe/seabed interaction mechanisms. The following facts demonstrate this point.

- *For cohesive soils, the sliding resistance is primarily dependent upon the surface contact area between the pipeline and the soil. This relates indirectly to submerged weight, since the surface contact area is a function of pipe embedment.*
- *For rocky seabeds, the lateral restraint can be due to mechanical interlocking between the pipeline and the rocks and hence unrelated to sliding friction effects.*

The characteristics of the seabed should be examined for each individual case, and the implications with regard to resistance to pipeline movement should be established.

NOTE 3 For simple situations, e.g. relatively flat seabeds with a well-defined soil type, it is possible to define an effective coefficient of friction which reasonably represents the soil resistance to pipeline movement. The values in Table H.1 have been used in the past for North Sea applications and may be used with caution for similar conditions.

Table H.1 **Typical effective coefficients of friction for North Sea applications**

Seabed type	**Lateral friction**		**Axial friction**	
	Min.	**Max.**	**Min.**	**Max.**
Non-cohesive (e.g. sand)	0.5	0.9	0.55	1.2
Cohesive (e.g. clay, silt)	0.3	0.75	0.3	1.0

H.2.7.3 Bearing capacity

Soil bearing capacity should be evaluated using soil mechanics theory applied to the results of in situ tests.

H.2.7.4 Sediment transport effects

NOTE 1 In areas of non-cohesive seabed soils, the following sediment transport-related processes can take place:

a) scour formation around pipeline and other installations;

b) movement of sandwaves and other bedforms;

c) natural backfill;

d) self-burial;

e) beach drawdown.

Sediment transport-related processes should be evaluated using loose bed transport theory to determine the relative rates of erosion and deposition of seabed soil around the pipeline or installation.

In all cases, the potentially adverse consequences of these effects should be evaluated.

NOTE 2 In some cases natural backfill and self-burial can be beneficial in allowing artificial backfill and burial operations to be avoided.

H.2.7.5 Liquefaction

NOTE Soils, particularly single size loose fine-grained sand, can be subject to liquefaction.

Possible causes of liquefaction that should be taken into account include:

a) wave action;

b) seismic action.

Evaluation of liquefaction effects should take into account the relative rates of pore water pressure build-up and dissipation within the soil.

H.2.7.6 Slope stability

Seabed survey data should be examined for evidence of slope instability on or near the pipeline route. The following should also be taken into account:

a) presence of triggering effects such as waves or seismic action;

b) sediment transport processes leading to deposition at the top of the slope or erosion near the base.

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