

PD 8010-2:2015+A1:2016



BSI Standards Publication

PUBLISHED DOCUMENT

Pipeline systems –

Part 2: Subsea pipelines – Code of practice

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Summary of pages

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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This part of PD 8010 supersedes PD 8010-2:2015, which is withdrawn.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

The start and finish of text introduced or altered by Amendment No. 1 is indicated in the text by tags **A1** **A1**. Minor editorial changes are not tagged. Previous amendments are not indicated.

PD 8010-2:2015 was a full revision of the standard, and introduced 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 = 10⁵ N/m² = 10⁵ 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.

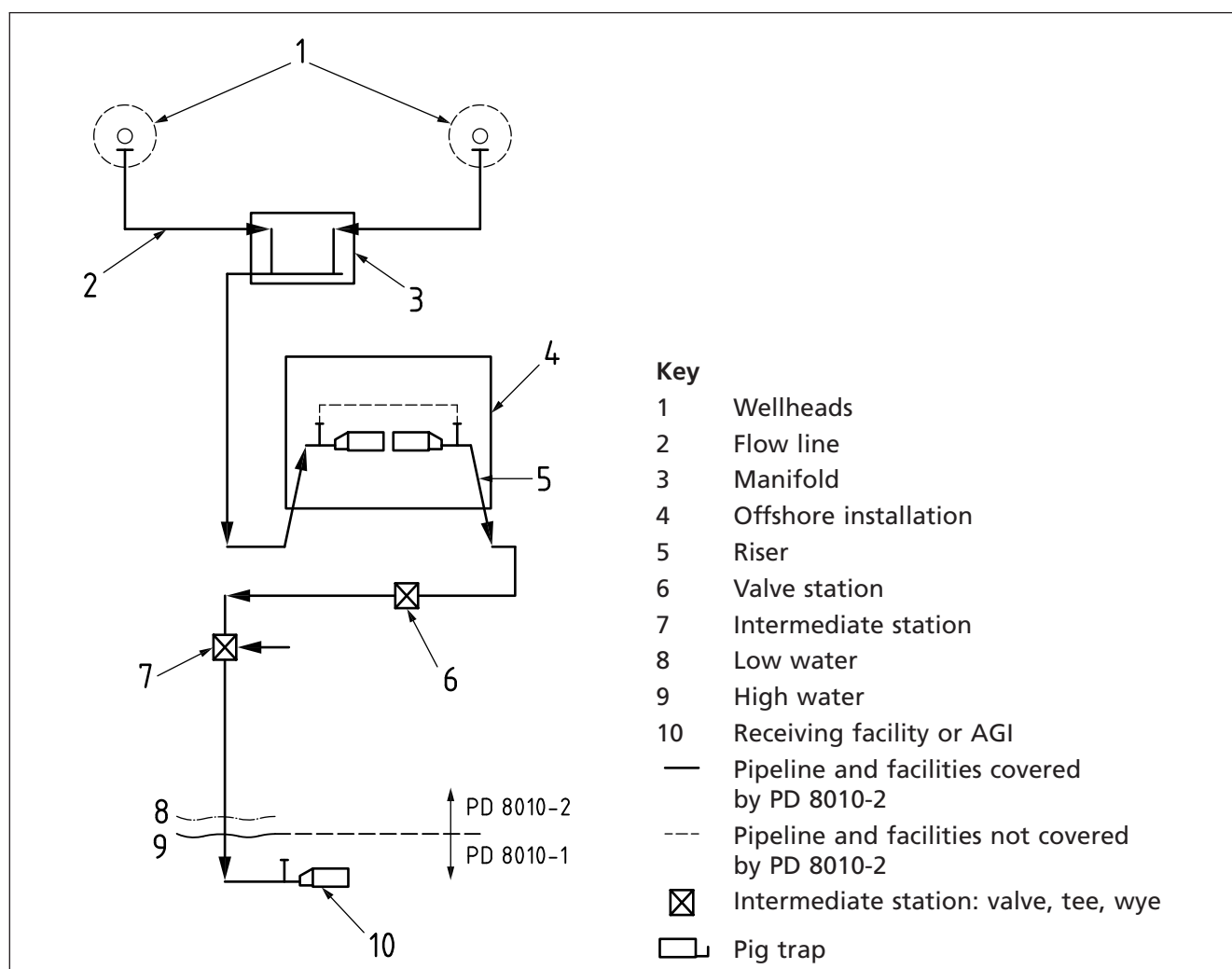
This part of PD 8010 is applicable to subsea pipelines intended for the conveyance of hydrocarbon liquids, hydrocarbon gases, carbon dioxide and other gases, liquids and gases in two-phase flow, fluid-based slurries and water.

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-OS-F101  are applicable.

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



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 butt welding 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
<i>NOTE 1 The term "initial" refers to the deflection due to influences, including fabrication and bending loads, other than hydrostatic pressure.</i>	
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 <i>NOTE 2 This is equal to the variance on the sea surface elevation.</i>
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	$\sqrt{A_1}$ radius of obstruction, e.g. jacket leg or riser, in metres (m) $\sqrt{A_1}$
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) <i>NOTE 3 This excludes corrosion allowance and mill tolerance.</i>
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) <i>NOTE 4 This incorporates components due to both wave action and steady current.</i>

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	$\sqrt{A_1}$ distance from the centre line of an obstruction to the point of measurement, in metres (m) $\sqrt{A_1}$
α	wave-induced water particle acceleration normal to the pipe axis, in metres per second squared (m/s ²)
α_{fab}	fabrication factor
α_r	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

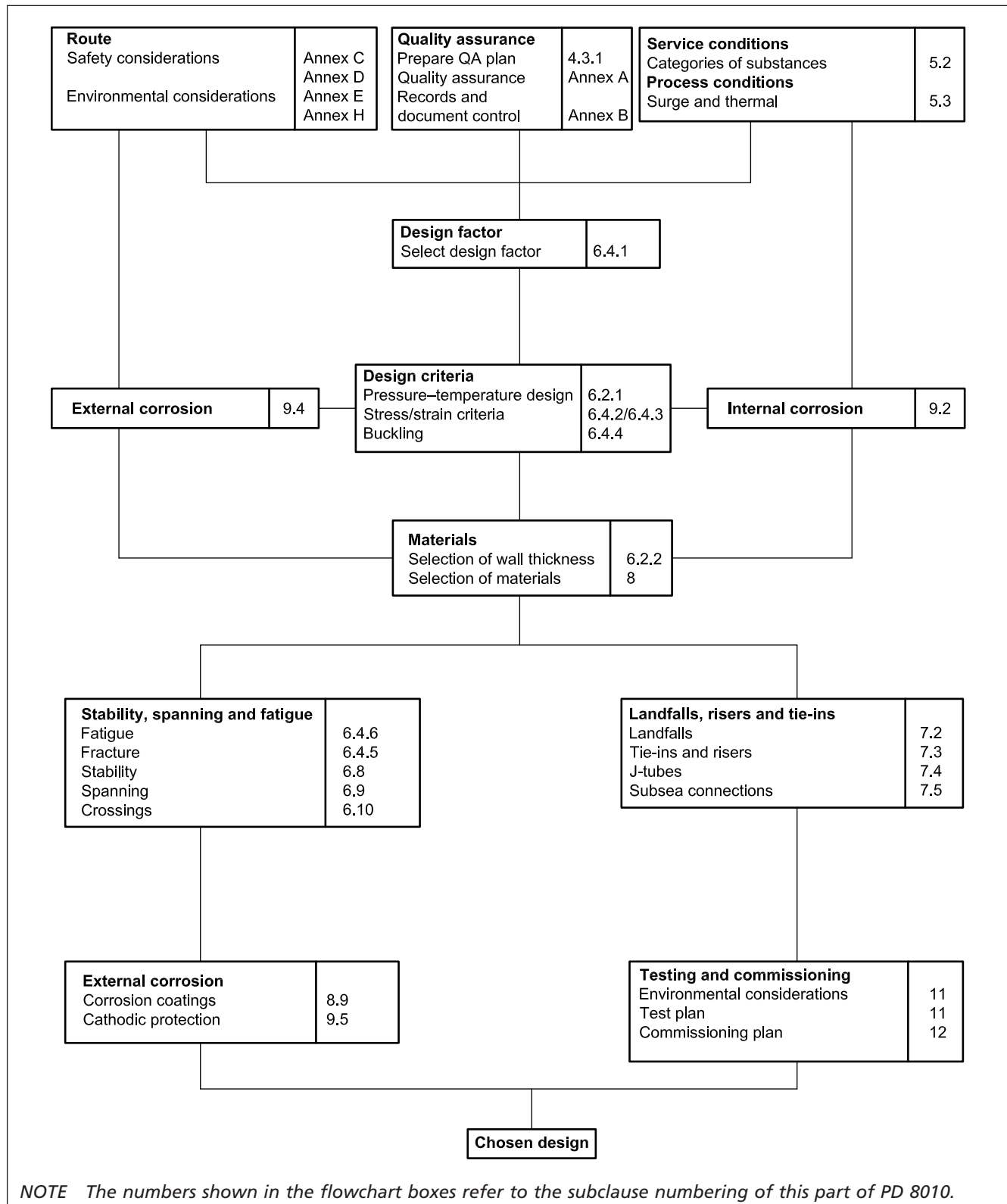
Routeing plans should be developed at an appropriate scale showing the overall pipeline route, proximity of adjacent infrastructure, e.g. other pipelines, cables, offshore production facilities, exploration block ownership, seabed bathymetry and geotechnical features. Features such as pipeline tie-ins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



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 CO₂ 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).

$$t_{\text{thin}} = \frac{50}{n + 1} \quad (1)$$

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.

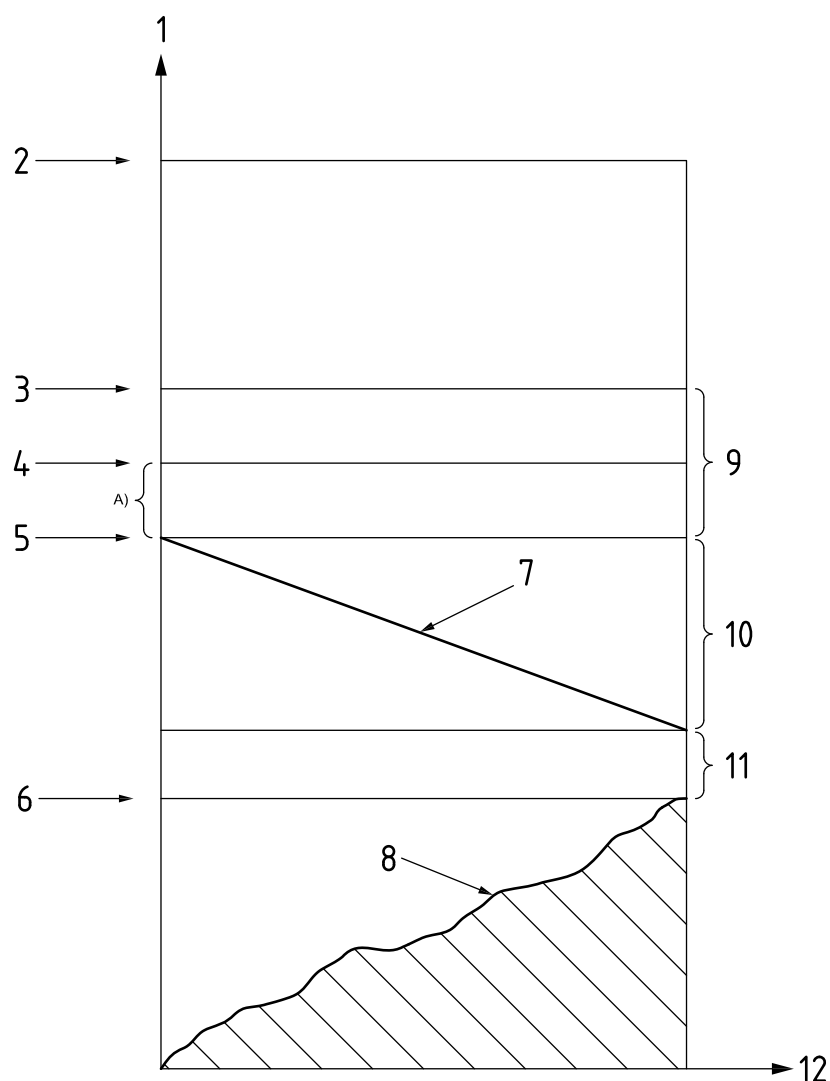
6.3.2 Internal design pressure

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 | 7 Hydraulic gradient |
| 2 Test pressure | 8 Ground profile |
| 3 $1.10 \times$ internal design pressure | 9 Surge pressure, thermal and other variations |
| 4 Net internal design pressure ^{A)} | 10 Pressure recommended to overcome friction losses |
| 5 Maximum allowable operating pressure ^{A)} | 11 Recommended backpressure |
| 6 Static head pressure | 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).

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

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.

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

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).

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

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.

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

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).

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

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).

$$\tau = \frac{T}{2Z} + \frac{2F_s}{A} \quad (7)$$

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.

- The allowable hoop stress criterion (see 6.4.2.1 and 6.4.2.2) is met.
- Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.005 (0.5%).
- 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).

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

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.

- 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/mm²; or
- b) the system designed can be shown to replicate closely a previously analysed acceptable design.

The 35 N/mm² 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).

$$\mu(W_S - F_L) \geq S_F(F_D + F_I) \quad (9)$$

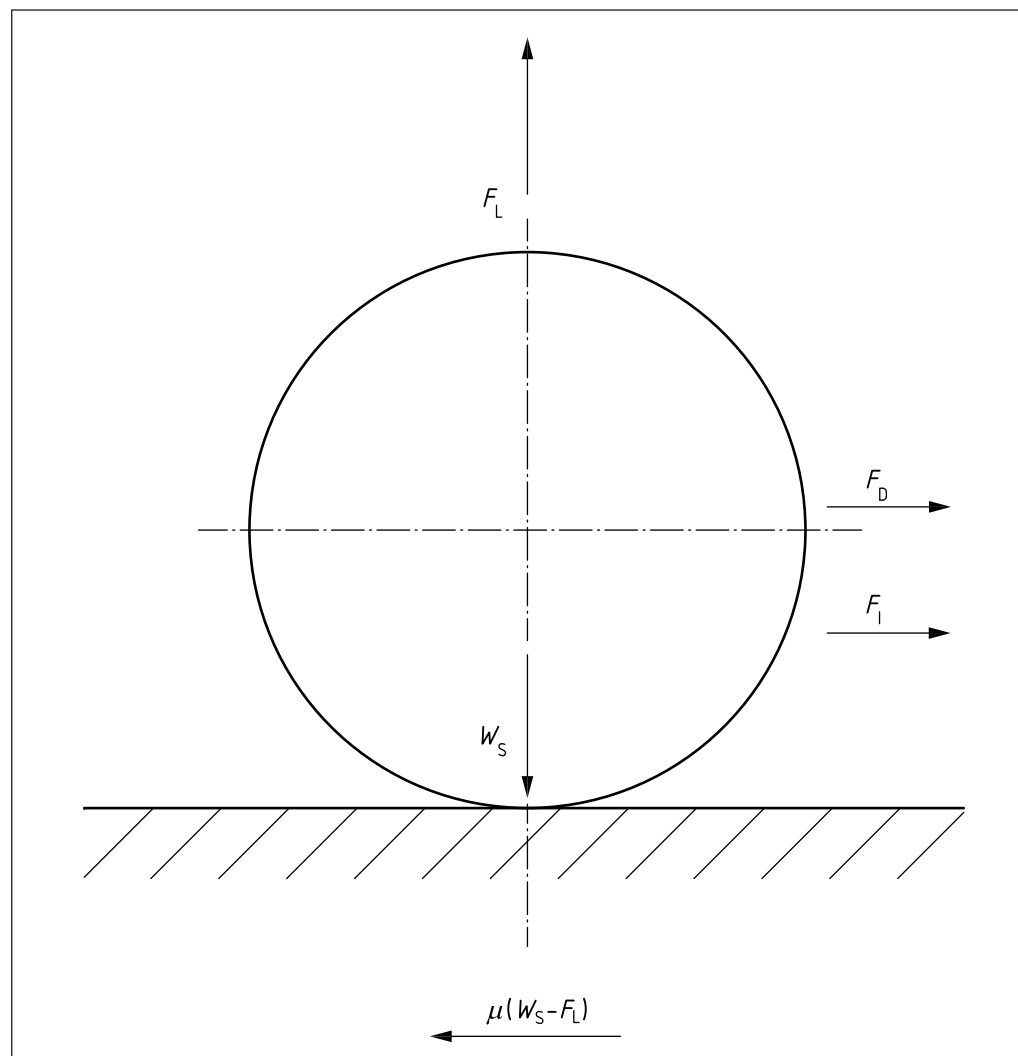
NOTE 1 A value of 1.1 is commonly used for the safety factor. In exceptional circumstances, where environmental conditions are known to a high degree of certainty, a lower value can be applied.

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

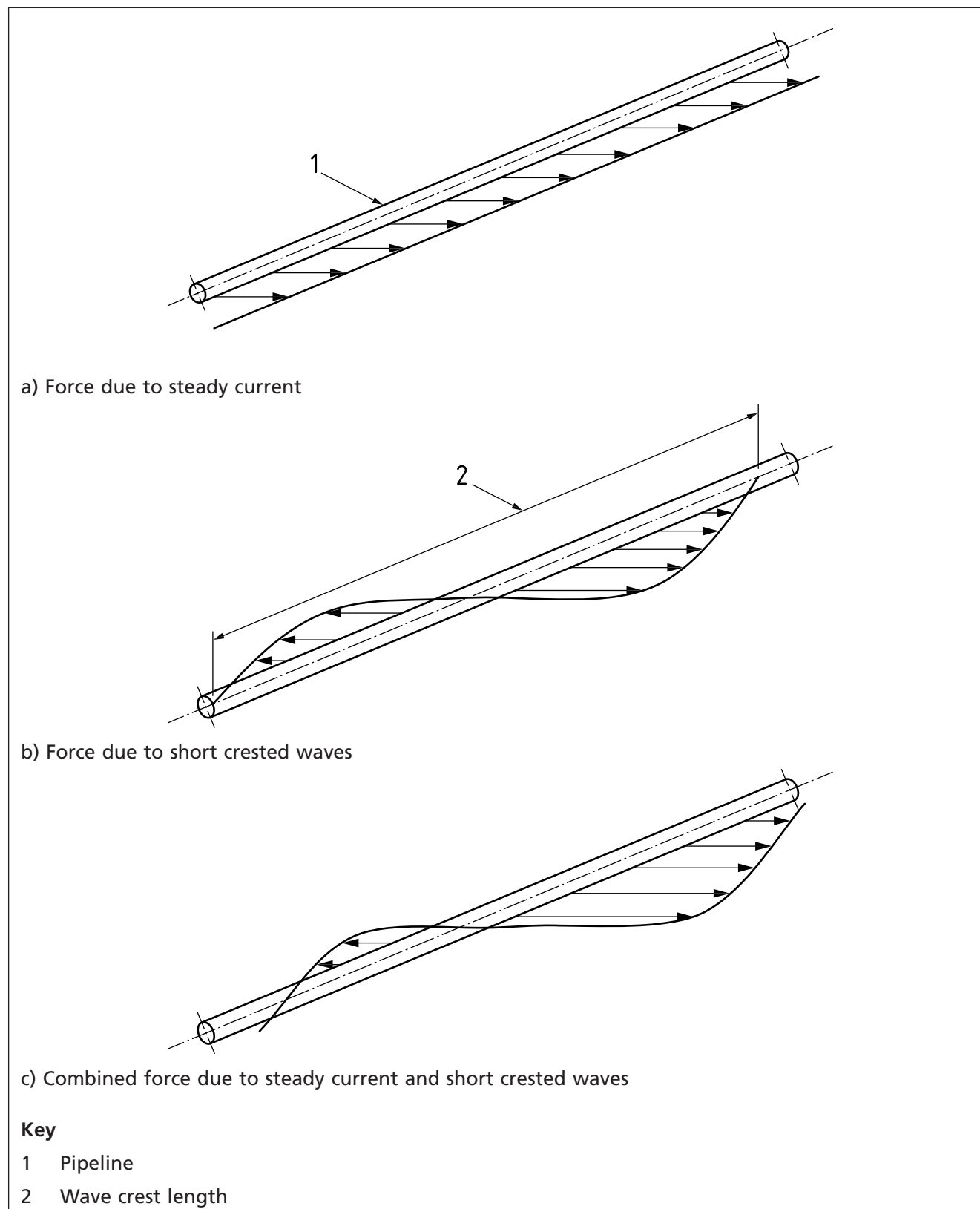


6.8.1.3 Three-dimensional analysis method

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



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.