British Standard

BRITISH STANDARD

BS 8010-3:1993

Incorporating Amendment No. 1

Code of practice for

Pipelines —

Part 3: Pipelines subsea: design, construction and installation

Committees responsible for this British Standard

The preparation of this British Standard was entrusted by Technical Committee B/203 Pipelines to Subcommittee B/203/3, Pipelines subsea, upon which the following bodies were represented:

Association of Consulting Engineers
British Compressed Gases Association
British Steel Industry
Health and Safety Executive
Institute of Gas Engineers
Institute of Petroleum
Institution of Water and Environmental Management
Ministry of Agriculture, Fisheries and Food
Pipeline Industries Guild
United Kingdom Offshore Operators Association

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Contents

Foreword

This Part of BS 8010 has been prepared under the direction of Technical Committee B/203. BS 8010 is a complete revision of all Parts of the original code of practice previously numbered CP 2010. BS 8010 is to be published in four Parts as follows:

— *Part 1: Pipelines on land: general;*

— *Part 2: Pipelines on land: design, construction and installation;*

— *Part 3: Pipelines subsea: design, construction and installation;*

— *Part 4: Pipelines on land and subsea: operation and maintenance.*

Part 3 (which was not covered by CP 2010) contains information on the design, construction and installation of subsea pipelines, whether steel or of a flexible composite construction.

Attention is drawn to the principal Acts of Parliament, which enable pipelines to be constructed and which regulate procedures. These are listed in Appendix A of BS 8010-1:1989.

A British Standard does not purport to include all the necessary provisions of a contract. Users of British Standards are responsible for their correct application.

Compliance with a British Standard does not of itself confer immunity from legal obligations.

Summary of pages

This document comprises a front cover, an inside front cover, pages i to iv, pages 1 to 74, an inside back cover and a back cover.

This standard has been updated (see copyright date) and may have had amendments incorporated. This will be indicated in the amendment table on the inside front cover.

Section 1. General

1.1 Scope

This Part of BS 8010 gives recommendations for the design, construction, installation, testing and commissioning of subsea pipelines constructed from steel and metallic reinforced polymers. It is not intended to replace or duplicate hydraulic, mechanical or structural design manuals.

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

NOTE 1 Installations or activities outside the scope of this standard may directly influence the design, construction or commissioning of subsea pipelines and are thus included where appropriate.

Although primarily concerned with subsea pipelines associated with the oil and gas industry, this Part of BS 8010 is likely to have application to a wider range of offshore activities. Standards other than those referred to in this document may be applied in such cases provided that they require at least an equivalent performance.

NOTE 2 Practices and materials covered adequately in other references and standards are duplicated herein only to such an extent as may be found convenient to minimize excessive cross-reference.

This Part of BS 8010 does not cover sea outfalls (see BS 8005-4:1987) or fluid umbilicals (see BS 5173).

1.2 References

1.2.1 Normative references

This Part of BS 8010 incorporates, by reference, provisions from specific editions of other publications. These normative references are cited at the appropriate points in the text and the publications are listed on page 71. Subsequent amendments to, or revisions of, any of these publications apply to this Part of BS 8010 only when incorporated in it by updating or revision.

1.2.2 Informative references

This Part of BS 8010 refers to other publications that provide information or guidance. Editions of these publications current at the time of issue of this standard are listed on page 75, but reference should be made to the latest editions.

1.3 Definitions

For the purposes of this Part of BS 8010 the definitions given in BS 8010-1:1989 and in ISO 9000:1987 apply, together with the following.

1.3.1
bundle

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

1.3.2
design life

the period for which the design basis is planned to remain valid

1.3.3
external riser

a riser which is mounted in such a way that it experiences the action of wind, waves and currents

NOTE This can include risers located within the plan area of a platform.

1.3.4
internal design pressure

the pressure selected as the maximum sustained pressure exerted by the pipeline contents to which a pipeline is to be designed

1.3.5
internal riser

a riser which is located within a platform leg or other part of the platform structure so as to be effectively sheltered against the action of wind, waves and currents

1.3.6
J-tube

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

1.3.7
maximum allowable operating pressure (MAOP)

the maximum internal sustained pressure for which the pipeline is qualified. It is essential that it does not exceed the internal design pressure

1.3.8
pipe

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

NOTE It is also known as line pipe.

1.3.9
pipeline

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

NOTE It does not include piping systems such as process plant piping within offshore installations.

1.3.10
pipeline riser

that part of a pipeline that extends between a submarine pipeline on the sea floor and the pipeline termination point on a platform

NOTE The lower end interface between the riser and the submarine pipeline depends on the method of connection, geometry and type of riser, and should be agreed in each case.

1.3.11
pipeline system

an inter-connected system of subsea pipelines, their supports, all integrated piping components, the corrosion protection system and weight coating

1.3.12
pig trap

a device allowing entry to the pipeline system for the launching and receiving of pigs, and other equipment to be run through the pipeline

1.3.13
pull-tube

a straight tube installed on a platform, through which a pipeline can be pulled to form a riser

1.3.14
quality system

the organization, structure, responsibilities, procedures, processes and resources for implementing quality management

1.3.15
quality control

the operational techniques and activities that are used to fulfil the requirements of quality

1.3.16
quality assurance

all those planned and systematic actions necessary to provide adequate confidence that a product or service will satisfy given requirements of quality

1.3.17
riser system

the riser, its supports, all integrated piping components and corrosion protection system

1.3.18
subsea pipeline

a pipeline laid under maritime waters and estuaries, and the shore below high water mark

NOTE Terminal interfaces are as follows.

a) At the landfall, the pipeline may extend onshore to a terminal, in which case BS 8010-2 will apply to the onshore section. Both Parts 2 and 3 of this British Standard are relevant to the shore area and Part 2 should be consulted.

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 will be up to and including the first valve above sea water level or the emergency shut down (ESD) valve if fitted for either internal or external risers. If the pig trap or any associated pipework is located within a process area, other standards more stringent than this standard may be applicable and should be followed.

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

d) At an underwater installation where none of the above definitions are applicable, the pipeline terminates at the pull-in connection. The tie-in spool piece is considered 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 which is associated with the loading system, when a transient tanker is used.

f) Instrument tappings on the pipeline are part of the pipeline but the instrumentation is not.

1.3.19
slug catcher

a device incorporated into a gas or gas/liquid pipeline for the separation and removal of slugs of liquid from the pipeline

1.3.20
slurry

a type of multi-phase flow comprising a suspension of solid particles within a liquid

1.3.21
splash zone

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

1.3.22
transient pressure

pressure fluctuation created by an upset in the steady state flow conditions in a pipeline, normally caused by valve operation, pump start or trip-out, or by the fluctuation of a control valve and inaccuracies of instrument set points

NOTE Transient pressure may exceed the MAOP by not more than 10 %.

1.3.23
tow/trailing head

that part of the bundle for the purpose of installation cable attachment, which may also incorporate alignment devices and termination facilities

1.3.24
trim or weight chains

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

1.3.25
bulkheads

stress distribution diaphragms within an encased bundle. They may also be watertight compartment separation diaphragms

1.3.26
spacers

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

1.4 Symbols and units

1.4.1 Symbols

The symbols adopted in this Part of BS 8010 are chosen to be consistent with established usage. Subscripts are used to retain consistency whilst avoiding duplication of symbols. A table of symbols is given in Annex A.

1.4.2 Units

The international system of units (SI) (see BS 5555:1981) is followed in this Part of BS 8010. Exceptions are pipeline diameters, which are frequently given in inches in line with established usage, and pressure which is given in bar.

NOTE 1 bar = 10^5 N/m^2 = 10^5 Pa.

1.5 Safety

The recommendations included in this Part of BS 8010 are based upon considerations of safety extending throughout the lifetime of the pipeline.

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

The designer and owner of the pipeline should ensure that the design of the pipeline system is such that the risk to personnel during its construction, operation and maintenance is as low as is reasonably practicable.

Section 2. UK statutory requirements and guidance

2.1 General

This section covers the statutory requirements for the construction and use of a submarine pipeline in, under or over any part of the territorial waters adjacent to the United Kingdom or any designated areas of the UK continental shelf.

2.2 Regulations

Construction and use of a submarine pipeline is governed by the Petroleum and Submarine Pipelines Act 1975 (PSPA) [1], the Coast Protection Act 1949 [2], the Mineral Workings (Offshore Installations) Act 1974 (MWA) [3], the Petroleum Act 1987 [4], the Gas Enterprise Act 1982 [5] and the Health and Safety at Work etc. Act 1974 (HASWA) [6]. These Acts empower the Secretary of State to make Regulations which take the form of Statutory Instruments (SIs). The primary Regulatory Authority, the Pipelines Inspectorate of the Health and Safety Executive, should be contacted for advice on Regulations currently in force.

The following Regulations are of particular importance and should be consulted.

a) *SIs made under the Petroleum and Submarine Pipelines Act*

1) SI 1977/No. 835 The Submarine Pipelines (Inspectors) Regulations 1977 [7];

2) SI 1982/No. 1513 The Submarine Pipelines Safety Regulations 1982 [8];

3) SI 1985/No. 1051 The Submarine Pipelines (Exemption) Regulations 1985 [9];

4) SI 1986/No. 1985 The Submarine Pipelines Safety (Amendment) Regulations 1986 [10];

5) SI 1991/No. 680 The Submarine Pipelines (Inspectors and Safety) (Amendment) Regulations 1991 [11].

b) *SIs made under the Mineral Workings Act*

1) SI 1974/No. 289 The Offshore Installation Regulations 1974 [12];

2) SI 1989/No. 978 The Offshore Installations (included apparatus and works) Order 1989 [13].

c) *SIs made under the PSPA and the MWA*
SI 1989/No.1029 The Offshore Installations (Emergency Pipeline Valve) Regulations 1989 [14].

2.3 Guidance notes

The Department of Trade and Industry and the Pipelines Inspectorate of the Health and Safety Executive (HSE) issue guidance notes from time to time on such topics as the following:

a) applications for Works Authorizations (to construct a pipeline);

b) applications to deposit articles on the seabed;

c) applications to discharge the contents of a pipeline;

d) applications to bring (or return) a pipeline into use;

e) safety regulations;

f) technical aspects of pipeline design, construction and operation.

In addition, the Pipelines Inspectorate of the HSE issue safety notices on matters of safety which arise between subsequent issues of guidance notes.

2.4 Landfalls

Authorization by the Secretary of State for Energy under Section 1 of the Pipelines Act 1962 [15] is required for the onland section of a submarine pipeline where the combined length of the onland section and the submarine section is greater than 10 miles (a cross country pipeline). If the combined length of the onshore and submarine pipeline is 10 miles or less (a local pipeline) then, under Section 2 of the Pipelines Act 1962 [15], planning permission has to be obtained from the County Authority and notice has to be served on the commencement of construction. The Pipelines Act 1962 [15] will apply to that part of the pipeline on the landward side of the baseline established by the Territorial Waters Order in Council 1964 [16] (low water mark). It should be noted that the jurisdiction of the County Authority may also extend to the low water mark.

Under the Electricity and Pipeline Works (Assessment of Environmental Effects) Regulations, SI 1990/No. 442 [17], an Environmental Statement has to be submitted to the Secretary of State for Energy for all cross country pipelines.

2.5 International pipelines

A pipeline which crosses the continental shelves of two or more sovereign states will need to satisfy the requirements of the appropriate statutory authority for each state. In addition, an inter governmental treaty may be required.

2.6 Works Authorization

Application for a Works Authorization should be made to the Oil and Gas Division, Department of Trade and Industry, 1 Palace Street, London SW1E 5HE.

Section 3. Quality assurance

3.1 General

Quality assurance procedures should be applied in accordance with ISO 9000:1987[1].

3.2 Quality definitions

For the purposes of this standard, the quality definitions given in ISO 9000:1987 apply (see **1.3**).

3.3 Quality plans

Management should prepare specific written quality plans relative to each particular pipeline. Quality plans should cover all aspects of the pipeline design, construction and testing and should define the following:

a) the quality objectives to be attained;

b) the specific allocation of responsibilities and authority during the different phases of the project;

c) the specific procedures, methods and work instructions to be applied;

d) certificates, inspection and hold-points required;

e) suitable testing, inspection, examination and audit programmes at appropriate stages (e.g. design, manufacture, installation);

f) a method for implementing changes and modifications in a quality plan as the project proceeds;

g) material source, identification and documentation control procedures;

h) other measures necessary to meet quality objectives.

3.4 Design quality assurance

The design and construction of the pipeline system should be carried out under the supervision of a suitably experienced chartered engineer.

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

Procedures should be established and maintained to control and verify the design of the pipeline and to ensure that the specified requirements are met.

3.5 Materials quality assurance

3.5.1 Pipe and fittings

The quality plan should specify the tests and documentary evidence required to ensure that all pipeline components meet the specification against which they have been ordered. Each heat of steel should be certified. Manufacturing inspection should be specified.

Each pipe should be marked with a unique identification number so that its inspection certificate can be identified and its quality verified.

3.5.2 Stock material

Where material is purchased from stockholders, it is essential that the supplier provides satisfactory documentary certificates (either of original manufacture or by appropriate testing) that the material supplied is in accordance with the required specification.

3.5.3 Shop fabricated equipment

Shop fabricated or manufactured equipment (such as pig traps, manifolds, valves, flanges and insulation joints) should be constructed only from material which can be identified and its quality verified. It is recommended that fabrication should not commence until written certification is available and should only be undertaken by organizations able to demonstrate compliance with ISO 9000.

3.6 Construction quality assurance

The construction quality plan should detail the procedures to be employed and the means of ensuring compliance with them, in order to control the construction process. The method of recording, accepting or rejecting non-conformities should be established.

It should also identify the organization and responsibilities of those controlling the workmanship criteria. The procedures should include instructions for training, qualifying and periodic re-examination of personnel. Where the quality of workmanship is dependent upon highly skilled or specially trained personnel, only those qualified to perform the work should be used.

The construction quality plan should also identify the inspection, certification and construction records and reports required to confirm the quality and safety of the constructed pipeline.

[1] BS 5750-0.1 is identical to ISO 9000:1987.

3.7 Specialized activities

Offshore pipeline activities often involve specialized techniques developed for a particular activity. In such circumstances, quality assurance procedures should be developed in conjunction with the specialist contractors. If necessary, to ensure proper quality control, these should be developed in association with suitable simulations of the activity.

3.8 Records and document control

3.8.1 General

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.

3.8.2 Design documentation

The following documents should be maintained:

a) design basis manual;

b) design audits, change instructions and their implementation;

c) calculations and justification of assumptions relating to design, construction, testing, commissioning and operation;

d) materials and construction specifications;

e) approved construction and as built drawings;

f) authorized deviations from specification, with reasons or calculations which justify them, together with the signature, name and position of the person authorizing them.

3.8.3 Procurement documentation

The following documents should be maintained:

a) certificates of verification, testing and identification of material;

b) non-destructive testing (NDT) results and radiographs;

c) inspection reports;

d) weld procedure qualification certificates;

e) welder and NDT inspector qualification certificates;

f) manufacturing and fabrication procedures;

g) heat treatment certificates;

h) quality plans and manuals.

3.8.4 Construction documentation

The following documents should be maintained:

a) weld procedure qualification certificates, including heat treatment records;

b) welder and NDT inspector qualification certificates;

c) NDT inspection reports and radiographs;

d) weld repair reports and radiographs;

e) pipeline component reference numbers and length tally;

f) weather reports;

g) anchor tensions and pipe tension;

h) towing reports;

i) installation procedures and quality plans;

j) vessel log and position reports (cross-referenced to pipe reference numbers);

k) diving records.

3.8.5 Pressure testing and precommissioning documentation

The following documents should be maintained:

a) filling procedure and records;

b) test procedure;

c) instrument calibration certificates;

d) test records including calculations of air content, half-hourly pressure log and pressure and temperature charts;

e) precommissioning records.

3.8.6 Survey documentation

The following documents should be maintained:

a) pre-construction hydrographic survey;

b) "as laid" survey including video records;

c) soils survey;

d) side scan sonar or any other acoustic records.

3.8.7 Retention of documents and records

All construction documentation should be retained for at least 3 years following start up of the pipeline.

All design, testing and survey documentation should be prepared for retention for the life of the pipeline.

Section 4. Design

4.1 Design approach

4.1.1 Safety assessment

A pipeline system should be designed to convey substances from one location to another without loss of integrity. The risks to people created by the pipeline should be as low as reasonably practicable throughout the construction, operation and abandonment phases.

To fulfil these objectives the design process should continuously assess the risks to the pipeline along its entire length and the methods available to avoid, or mitigate the consequences of those risks. The assessment should take into account all reasonably foreseeable events, as they are identified during the design process, which could impair the integrity of the pipeline. The likelihood of the occurrence of these events together with the consequence of the events should be evaluated so as to determine the overall risk. In certain circumstances the consequence of an event may be so intolerable that it is unnecessary to determine the likelihood of the event occurring. In such cases the avoidance or mitigating measures are automatically adopted.

The analysis of the risks to the pipeline, e.g. field pressures, platform layout, should commence at the first conceptual stage of the project. As the project progresses into the detailed design stage, so the above analyses should be re-examined and further analyses carried out, e.g. internal and external corrosion risks and third party (anchor and trawl board) risks. Throughout the design the level of analysis and re-evaluation should be commensurate with the risks identified.

The analyses may identify a choice of mitigating measures such as anti-corrosion coatings, complex steels, inhibition, cathodic protection and these have to be evaluated, both in isolation and in combination, in terms of their effectiveness in the reduction of risk.

This process of re-evaluation of previous safety assessments and developing design ensures that the final design achieves the safety objectives in a manner that is both effective and demonstrable.

All components of the pipeline system should be considered, including the following:

a) lateral connections;

b) valves, bends and fittings;

c) pig traps;

d) subsea slug catchers;

e) expansion devices;

f) tie-ins;

g) corrosion prevention and monitoring systems;

h) pipeline shut down valves;

i) riser systems;

j) integrity monitoring systems.

4.1.2 Design interface

Design interfaces should be clearly defined.

NOTE Selection of these interfaces should take due account of the limits to the application of this standard as given in **1.1** and to the definition of a subsea pipeline in **1.3**.

4.1.3 Pipeline contents

The following characteristics of the pipeline contents should be established:

a) composition;

b) density;

c) viscosity;

d) phase;

e) pressure;

f) temperature;

g) flammability;

h) corrosivity;

i) toxicity.

4.1.4 Design life (see 1.3.2)

A design life should be established for a pipeline system in order that long term responses to effects such as fatigue, corrosion, variation in service parameters and external environmental factors can be assessed.

4.1.5 Pipe sizes

API 5L:1991 should be consulted for standard pipe sizes.

4.1.6 Routing

4.1.6.1 *Survey*

Data should be collected by hydrographic survey of the proposed route prior to final selection of the pipeline corridor.

This survey should include investigation of the following:

a) seabed geology and features;

b) bathymetry;

c) environmental and oceanographic data;

d) wellheads, wrecks and debris;

e) marine growth;

f) landfall.

4.1.6.2 *Route selection*

The following should be considered when selecting the route:

a) type and intensity of shipping and the presence of anchoring zones;

b) type and intensity of fishing activity;

c) presence of fishing grounds and other sensitive areas;

d) presence of other pipelines, installations or wellheads;

e) presence of wrecks or other obstructions;

f) presence of regularly dredged areas and dumping grounds;

g) operators whose blocks are crossed by the pipeline;

h) presence of submarine cables;

i) designated dangerous zones;

j) sediment transport;

k) sediment types;

l) seabed instability;

m) installation limitations;

n) connections to existing facilities;

o) seabed currents.

4.1.6.3 ***Landfall***

When a landfall is involved, information should be obtained concerning the following:

a) waves;

b) tides;

c) scour;

d) coast erosion;

e) beach movement;

f) topography;

g) geology;

h) environmental sensitivity.

Reference should also be made to BS 8010-2.8:1992.

4.1.6.4 ***Tolerances***

The pipeline should be installed within 100 m of the selected pipeline route and never installed outside the survey corridor. The limit of deviation from the selected pipeline route should be reduced in congested areas.

4.1.7 Installation method (see also section **10**)

Factors to be considered during the assessment of pipeline installation methods should include the following:

a) pipeline materials and dimensions;

b) pipeline weight (submerged and in-air);

c) water depths;

d) environmental conditions;

e) topography and stability of seabed;

f) existing facilities;

g) pipeline coatings.

4.1.8 Integrity monitoring

4.1.8.1 ***General***

A pipeline integrity monitoring system should be considered at the design stage and consist of the following:

a) corrosion monitoring (internal and external);

b) inspection (internal and external);

c) leak detection.

4.1.8.2 ***Corrosion monitoring***

The following should be considered:

a) installation of corrosion coupons at each end of the pipeline;

b) installation of probes at each end of the pipeline;

c) monitoring of contents;

d) monitoring of cathodic protection system.

4.1.8.3 ***Inspection***

Consideration should be given to providing for the running of internal inspection tools, which would require:

a) limited internal diameter changes;

b) suitable pig trap design and accessibility;

c) sufficient bend radii;

d) full bore pipeline valves;

e) suitable tees and y-pieces;

f) assessment of internal linings.

4.1.8.4 ***Leak detection***

Combinations of the following should be considered:

a) continuous mass balance of the pipeline contents;

b) continuous volumetric balance (corrected for temperature and pressure) of the pipeline contents;

c) continuous monitoring of rate of change of pressure;

d) continuous monitoring of rate of change of flow;

e) real-time computer simulation;

f) low-pressure alarms;

g) high-flow alarms;

h) reverse flow alarms;

i) visual inspection of the pipeline route;

j) visual inspection of the sections of the pipeline risers above water.

4.2 Design of steel pipelines

4.2.1 Loads

4.2.1.1 ***Types of load***

The following should be considered:

a) self-weight (including weight of steel, coatings, attachments, contents and marine growth);

b) external hydrostatic pressure;

c) buoyancy effects;

d) internal fluid loads, e.g. pressure, inertial effects;

e) installation forces (such as reeling loads, tow loads, applied lay tension, and trenching forces);

f) loads due to changes of pressure and temperature;

g) environmental loads;

h) seabed stability settlement and platform movement;

i) loads arising from fishing and other activities and dropped objects near platforms.

4.2.1.2 ***Pressure*** (see **1.3**)

In selecting the internal design pressure, consideration should be given to the maximum steady shut in pressure and also the well kill pressure where pipelines are connected to wells. During the design process the target MAOP will generally be identical to the internal design pressure and protection systems should be considered to ensure the transient pressures will not exceed 110 % of the MAOP.

4.2.1.3 ***Residual loads***

Residual loads should be considered in all cases where they may adversely affect the pipeline. Where these loads cannot be accurately established, a conservative estimate should be made of their values.

4.2.2 Design loading conditions

4.2.2.1 ***Loading conditions to be considered***

In order to demonstrate the suitability of the design, the following loading conditions should be considered:

a) construction loads;

b) hydrostatic testing;

c) functional loads;

d) functional and environmental loads;

e) functional plus predictable accidental loads which can be reasonably accommodated.

The loads making up each loading condition should be considered in the most unfavourable combinations which can be expected to occur.

4.2.2.2 ***Construction loads***

These loading conditions would include all loads (except any intermediate hydrostatic testing) to which the pipeline system is subject prior to its final hydrotest. These loads should include those arising from the following:

a) fabrication of pipe strings;

b) installation;

c) tie-ins;

d) any repair for which the system is decommissioned;

e) environmental forces;

f) pipe stacking.

Where environmental loading is considered, the applied loading should be selected to reflect the most severe loading likely to be encountered during the construction phase under consideration (see **B.1.2**).

4.2.2.3 ***Hydrostatic testing***

An analysis should be performed to ensure that the pipeline and its supports can accommodate the loads which occur during hydrostatic testing. These include the effects of the weight of contents and of pipeline expansion.

4.2.2.4 ***Functional loads***

These loading conditions include:

a) weight of the pipeline system and its contents;

b) thermal effects;

c) pressure effects;

d) transient operational effects;

e) hydrostatic pressure of the environment;

f) residual installation load remaining after hydrotest.

4.2.2.5 ***Functional and environmental loads***

Environmental loads are due to wind, waves, currents, earthquakes and other environmental phenomena. Combinations of environmental and functional loads should be selected by considering the likelihood of simultaneous occurrence.

Whilst loads associated with a storm (e.g. wind and waves) should be considered together, it is not necessary to combine independent extreme environmental loads (e.g. storm and earthquake) in a single load case. The treatment of environmental loads is described in Annex B.

4.2.2.6 ***Functional plus accidental loads***

Accidental loads should be considered in combination with the least favourable functional loads. Accidental loads should be considered in relation to their likely frequency of occurrence.

It is not necessary to consider combinations of accidental loads, or accidental loads in combination with extreme environmental loads, unless they can be reasonably expected to occur together.

4.2.3 Strength consideration

Where a layer of cladding is applied to the pipe, this should not be considered to contribute to the strength of the pipeline unless the contribution can be demonstrated. Any adverse effects of the cladding on the strength of the pipe should be considered. The strength of welded joints in clad pipelines should be considered. Considerations should be given to the effect on weld strength of special requirements for welding of clad pipelines.

4.2.4 Selection of design factors

4.2.4.1 ***Substance categorization***

Substances conveyed by pipelines are categorized in BS 8010-2.8:1992. However for subsea pipelines no distinction in the selection of design factors is recommended.

4.2.4.2 ***Design factors***

The design factor, f_d, appropriate to the assessment of allowable stress is given in Table 1. Alternatively, the acceptability of construction loads may be assessed on an allowable strain basis.

Where the pipeline design temperature is outside the range – 25 °C to 120 °C, consideration should be given to reduction of the design factor.

Table 1 — Design factors f_d

Hoop stress		Equivalent stresses resulting from functional and environmental or accidental loads		Equivalent stresses arising from construction or hydrotest loads	
Riser	Seabed	Riser	Seabed	Riser	Seabed
0.6	0.72	0.72	0.96	1.0	1.0

4.2.5 Stress evaluation

4.2.5.1 ***Hoop stress***

Hoop stress should be calculated using the following thin-wall equation when the ratio of $D_o : t$ is greater than 20.

$$\sigma_h = (P_i - P_o)\frac{D_o}{2t} \tag{1}$$

where

σ is the hoop stress (in newtons per square metre);

P_i is the internal pressure (in newtons per square metre);

P_o is the external pressure (in newtons per square metre);

D_o is the outside pipe diameter (in metres);

t is the minimum wall thickness (in metres).

The wall thickness used for hoop stress calculation should be the minimum value allowing for permitted wall thickness variations and subtracting any corrosion allowance.

The following more accurate thick wall equation may be used when the ratio of $D_o : t$ is less than or equal to 20.

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

where

D_i is the inside pipe diameter ($D_o - 2t$) (in metres).

4.2.5.2 ***Longitudinal stress***

The total longitudinal stress should be the sum of the longitudinal stresses arising from pressure, bending, temperature, weight, other sustained loadings and occasional loadings.

A pipeline should be considered totally restrained when axial movement and bending resulting from temperature or pressure change is totally prevented.

4.2.5.3 ***Shear stress***

The shear stress should be calculated from the torque and shear force applied to the pipeline using the following equation:

$$\tau = \frac{1000T}{2Z} + \frac{2F_s}{A} \tag{3}$$

where

τ is the shear stress (in newtons per square metre);

T is the torque applied to the pipeline (in newton metres);

F_s is the shear force applied to the pipeline (in newtons);

A is the cross-sectional area of the pipe wall (in square metres);

Z is the pipe section modulus (in cubic metres).

4.2.5.4 ***Equivalent stress***

Equivalent stresses should be evaluated using the von Mises' stress criterion:

$$\sigma_e = (\sigma_h^{\,2} + \sigma_L^{\,2} - \sigma_h\sigma_L + 3\tau^2)^{½} \qquad (4)$$

where

- σ_e is the equivalent stress (in newtons per square metre);
- σ_h is the hoop stress (in newtons per square metre);
- σ_l is the longitudinal stress (combination of direct and bending stresses) (in newtons per square metre);
- τ is the shear stress (in newtons per square metre).

NOTE Nominal wall thickness may be employed in the evaluation.

Stress in the pipeline system should satisfy the following inequality:

$$\sigma_A < f_d\sigma_y \qquad (5)$$

where

- σ_A is the allowable stress, either hoop or equivalent (in newtons per square metre);
- f_d is the design factor (see **4.2.4**);
- σ_y is the specified minimum yield stress of pipe (in newtons per square metre).

4.2.5.5 ***Pipeline fittings and equipment***

The pipeline design should take account of flexibility of bends and other fittings. Stress intensification in bends and other fittings should be considered (see BS 806:1990).

4.2.6 Alternative design for strain

The limit on equivalent stress recommended in **4.2.5.4** may be replaced by a limit on allowable strain, provided that all the following conditions are met.

a) Under the maximum operating temperature and pressure, the plastic component of the equivalent strain does not exceed 0.001 (0.1 %). The reference state for zero strain is the as-built state (after pressure test). The plastic component of the equivalent uniaxial tensile strain is defined as:

$$\varepsilon_p = \left\{\frac{2}{3}(\varepsilon_{pL}^{\,2} + \varepsilon_{ph}^{\,2} + \varepsilon_{pr}^{\,2})\right\}^{½} \qquad (6)$$

where

- ε_p is the equivalent plastic strain [non-dimensional (ND)];
- ε_{pL} is the principal longitudinal plastic strain (ND);
- ε_{ph} is the principal circumferential (hoop) strain (ND);
- ε_{pr} is the radial plastic strain (ND).

b) 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 temperatures;

c) The D_o/t ratio does not exceed 60;

d) Welds have adequate ductility to accept plastic deformation.

Plastic deformation reduces pipeline flexural rigidity; this effect may reduce resistance to upheaval buckling and should be checked if upheaval buckling might occur.

NOTE This clause does not affect the limit on allowable hoop stress.

4.2.7 Allowable strain (for construction purposes only)

4.2.7.1 ***Use of allowable strain in design***

As an alternative to the evaluation of stress as recommended in **4.2.5**, the maximum strain in the pipeline may be considered. This approach is only permissible where geometric considerations limit the maximum strain to which the pipeline can be subjected and where the controlled strain is not of a cyclic or repeated nature.

Typical applications include pipeline reeling and J-tube installation.

4.2.7.2 ***Critical strain***

Critical strain should be determined in the following situations.

a) The pipe material and weld properties (hardness, toughness, ratio of yield strength to ultimate strength etc.) remain within acceptable limits for the proposed service.

b) Ovalization and other geometrical changes do not adversely affect the integrity of functioning of the pipeline.

c) The pipeline is not subject to local buckling (see **4.2.9**).

4.2.7.3 ***Maximum allowable strain***

For a situation of controlled strain where the displacements of the pipe are bounded, the maximum allowable strain should be limited to the following ratio of the critical strain (ε_c):

maximum allowable strain = 0.67 ε_c

4.2.7.4 ***Coatings***

Consideration should be given to the effect of strain on the integrity of pipeline coatings including concrete.

4.2.8 Fatigue

4.2.8.1 ***Fatigue loads***

All fluctuating loads should be considered in establishing the effect of fatigue on the pipeline system. Loads producing stresses below the threshold for fatigue damage need not be considered further.

Typical sources of fluctuating loads include the following:

a) wave forces;

b) vibrations caused by vortex shedding, product flow, or other phenomena;

c) operational cycles;

d) alternating movements of platforms and other structures.

4.2.8.2 ***Fatigue life***

Consideration should be given to the fatigue life of pipelines to ensure that minor defects do not grow to a critical size under the influence of cyclic loading.

The maximum number of stress cycles expected for a pipeline should be evaluated by multiplying the number of daily cycles occurring for the principal stress within a given stress range by the constant C in Figure 1. More complex daily stress cycles should be evaluated by multiplying the number of individual stress cycles, within the daily cycle, by the constant C in Figure 1. The sum of factored and unfactored cycles should not exceed 15 000.

Alternatively, a more comprehensive fatigue analysis based upon the fracture mechanics methods in PD 6493:1991 and S-N curve data may be used.

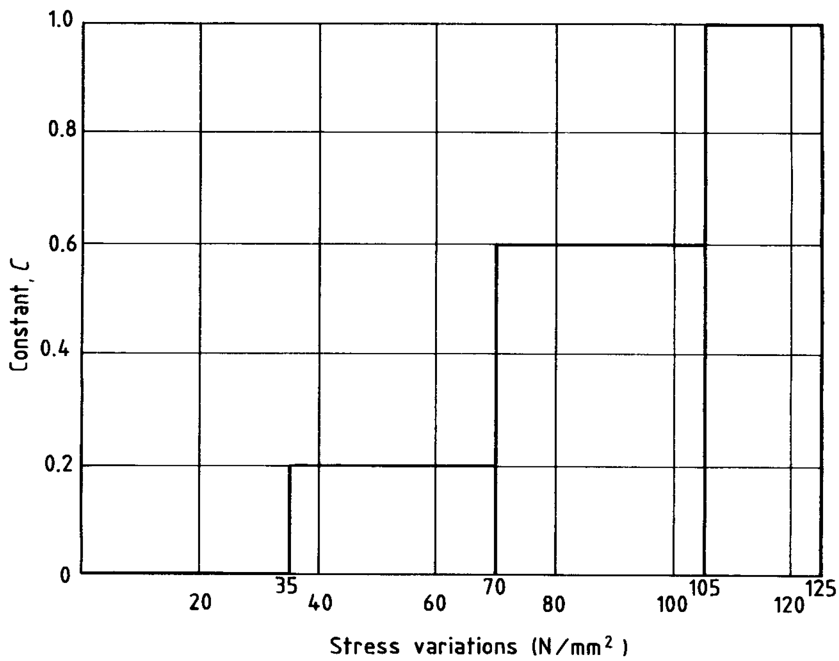

Figure 1 — Fatigue life, constant C for stress variations

4.2.9 Buckling

4.2.9.1 ***General***

The following buckling modes should be considered.

a) Local buckling of the pipe wall due to external pressure, axial compression, bending and torsion or combinations of these loads as dealt with in **C.1**.

b) Propagation buckling due to the external pressure, following the formation of local buckles or localized damage, as dealt with in **C.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 unburied, or vertical upheaval of trenched or buried, pipelines.

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

4.2.9.2 ***Ovalization***

In some situations, where loading is dominated by bending, buckling may not occur but unacceptable levels of ovalization may result. Ovalization may be calculated in accordance with the approach given in **C.3** in the absence of a more rigorous evaluation.

4.2.9.3 ***Coatings***

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

4.2.9.4 ***Controlled deformation***

Internal pressure and temperature can lead to transverse movements if the pipeline is not restrained, e.g. by burial. For unburied pipes in contact with the seabed, lateral movement is more likely and checks for snaking and buckling are necessary. For buried pipelines, upheaval buckling checks should be performed. **C.1** has information on the critical strain limits. **C.1.7** provides a conservative estimate of the bending strain.

4.2.9.5 ***Fracture***

Where the pipeline contains gas or a volatile liquid, the possibility that a fracture may propagate rapidly over a considerable distance should be considered.

The principal means of fracture control is by the selection of materials with adequate fracture toughness (see **5.1.4.5**). The material properties should be such that fracture results in a localized leak rather than complete rupture of the pipeline.

4.3 Design of flexible pipelines

4.3.1 Design approach

Flexible pipelines are proprietary items that do not lend themselves readily to analytical design of the type set out in **4.2**. Their design is therefore based on the specification and testing of the required functional properties and strengths. (See **4.3.5**.)

Design should satisfy that the characteristics of the flexible pipelines are suitable for the intended service.

The effect of longitudinal strain when the pipeline is under pressure should be taken into account.

4.3.2 Construction

Flexible pipelines are composites with metallic elements for mechanical strength and polymer layers to provide pressure containment and external corrosion or abrasion resistance.

An inner stainless steel carcass may be provided to resist collapse through external pressure and to provide wear resistance to pigs or through-flowline tools. This may be in the form of an interlocked wound helix or a continuous corrugated flexible tube.

4.3.3 Selection of materials

4.3.3.1 All materials used in the construction of high pressure flexible pipes should be selected in accordance with the design duty and service conditions.

4.3.3.2 The selection of polymers and elastomers should be such that they are flexible enough for any anticipated flexing but sufficiently rigid to avoid extrusion. The materials selected should be compatible with the product being conveyed at the design pressure and temperature for the design life of the pipelines. Polymers are to some extent permeable to high pressure gas, and this should be taken into account where an impermeable liner is not provided. Permeability of successive layers of different material should be such that gas may escape, or a relief system should be provided.

4.3.3.3 Reinforcements include high tensile steel wire and synthetic cord. Strength tests should be performed on each production batch of material before acceptance. Steel wires should be protected against corrosion.

4.3.3.4 Inner carcasses, if present, should be resistant to corrosion by the line contents being transported at the design pressures and temperature.

4.3.4 End fittings

The design of the termination should ensure transfer of all loads from the flexible pipe to the connector. Bending restrictors may be required to limit any eccentricity of loading. End fitting design may be qualified on the basis of past tests.

Proprietary connectors may be bonded directly to some types of flexible pipe eliminating any circumferential weld. A short length of steel pipe will permit the welding on of flanges or special connectors, or the linking up of several sections into a longer pipeline.

Terminations should be of sufficient length to avoid heat damage to the flexible pipe itself. Where a number of lengths of flexible pipe are to be assembled into a long line, the terminations should not be so long as to impair reeling the completed line for laying.

The inner lining should be connected in such a way as to give an unobstructed bore, particularly where pigs or through flowline tools are to be used. Liners (e.g. of corrugated stainless steel) should be bonded to the end sleeves with an impermeable joint. Sample bonds should be proof tested to at least 1.5 times the design load for axial tension, bending, torsion, internal design pressure and external collapse pressure. If more severe testing is required this should be specified.

4.3.5 Performance verification

The selection of a flexible pipe for a specific duty will depend upon the manufacturer's recommendations and product specification. However, some verification of expected performance is essential and the results of a manufacturer's proof test programme should be available. This should include the establishment of a satisfactory test programme and properly witnessed and certified test certificates.

Tests should include, but not necessarily be limited to the following:

a) burst pressure:	2 × maximum internal design pressure;
b) collapse pressure:	1.5 × rated external pressure;
c) bending:	0.67 × minimum design radius without collapse;
d) torsion:	1.5 × maximum design;
e) axial pull:	2 × maximum design load;
f) Chemical degradation tests for long term stability of polymers/elastomers used:	predicted life for intended service has to exceed design life of the pipe.

For dynamically loaded pipelines, in addition to the foregoing tests, sample pipe sections should be dynamically proof tested for fatigue in bending, torsion and axial tension modes whilst subject to the design internal pressure.

4.4 Bundles and multiple pipelines

4.4.1 General

4.4.1.1 *Bundles*

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. The characteristics of the smaller line and its impact on the bundle should be considered at the design stage.

An encased bundle comprises one or more pipelines fabricated within a sleeve, also known as carrier pipe.

4.4.1.2 *Functional requirements of sleeve pipe*

The sleeve may 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 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.

4.4.1.3 *Additional bundle components*

The bundle design should consider the following components.

a) *Tow/trailing head* at the ends of the bundle for the purpose of installation cable attachment which may also incorporate alignment devices and termination facilities.

b) *Trim or weight chains* attached to the bundle for the purpose of buoyancy adjustment to suit installation by towing.

c) *Bulkheads* either stress distribution diaphragms within an encased bundle or watertight compartment separation diaphragms.

d) *Spacers* provided to locate and support pipelines within the configuration of strapped or encased bundles.

e) *Thermal insulation systems.* Flowlines may require thermal insulation. This can take the form of either a dedicated insulation coating or provision of an insulating medium in the annulus (see **8.6**).

4.4.1.4 ***Stress considerations***

The combined section properties of all pipelines within the bundle configuration, including the sleeve pipe, should be used for installation and functional stress assessment.

The calculation of longitudinal strain and associated stresses should take account of the interconnection between the pipelines and the sleeve.

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.

4.4.2 Fabrication and installation

4.4.2.1 ***Fabrication and launch considerations***

Consideration should be given to the effect on design of the following:

a) *Fabrication site including the following factors:*

1) onshore launch site topography;

2) type and condition of launchway;

3) near shore launch site bathymetry;

4) provision for nearshore extension of launchway;

5) seabed soil conditions;

6) nearshore environmental conditions.

b) *Launch forces including the following factors:*

1) static and dynamic friction between bundle and launchway;

2) environmental forces on partially or completely launched bundles.

4.4.2.2 ***Tow considerations***

The following should be considered.

a) *For an on-bottom tow:*

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

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

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 considered in conjunction with environmental loading (see Annex B).

The effects of changes of buoyancy during installation should be considered.

4.4.3 Loads and load combinations

The design of bundled pipelines should consider the same loads and load combinations as recommended in **4.2.2**.

The following should also be considered.

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.

4.4.4 Design factors and stress evaluation (See **4.2.4**, **4.2.5** and **4.2.6**)

The following should be considered.

a) *Design factors.* Provided that suitable stability is established against environmental loading, then encased pipelines between pressure bulkheads (but not risers) may be considered as belonging to the seabed section for the application of design factors. (See Table 1).

b) *Stress evaluation.* Account should be taken of the installation method and the relative strengths of all pipelines in the bundle.

4.5 Stability

4.5.1 Approach

4.5.1.1 *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 consider the following effects:

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.

4.5.1.2 *Two-dimensional analysis method*

The two-dimensional analysis (see Figure 2) utilizes the following formula for horizontal pipeline stability: $\mu(W_s - F_L) \geq SF(F_D + F_I)$

where

μ	is the lateral soil friction coefficient;
W_s	is the submerged weight of pipeline per unit length (in newtons per metre);
F_L	is the hydrodynamic lift force per unit length (in newtons per metre);
F_D	is the hydrodynamic drag force per unit length (in newtons per metre);
F_I	is the hydrodynamic inertia force per unit length (in newtons per metre);
SF	is the safety factor.

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

Guidance on the derivation of these parameters is given in Annex B.

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

4.5.1.3 *Three dimensional analysis method*

Three-dimensional stability analysis may be considered (see Figure 3). Allowable movements should be based on acceptable stress levels and fatigue. Consideration should also be given to the possible loss of concrete due to movement and damage to the pipeline by third party activity.

4.5.2 Submerged weight

The submerged weight should be derived from the following.

a) The total weight of a steel pipeline should include the combined effect of all attachments and contents.

b) The increase in submerged weight resulting from water absorption should not be considered during installation. For subsequent analysis cases, water absorption may be considered (see **8.1.3**).

c) The specific gravity of the surrounding medium.

4.5.3 Hydrodynamic forces

Hydrodynamic forces should be determined in accordance with Annex B.

4.5.4 Soil instability and vertical stability

4.5.4.1 *Soil characteristics*

Soil characteristics to be established include the following:

a) soil type;

b) shear strength;

c) grain size distribution;

d) specific weight.

4.5.4.2 *Soil instability*

Soil instability may be initiated by any of the following:

a) seismic activity;

b) wave action and seabed current;

c) overloading due to weight of pipeline;

d) deposition or scouring of seabed soil material;

e) pipeline trenching;

f) pockmark and gaseous emissions;

g) slope failure.

When a pipeline is routed through an area of potential soil instability consideration should be given to stability enhancement methods (see **4.5.5**).

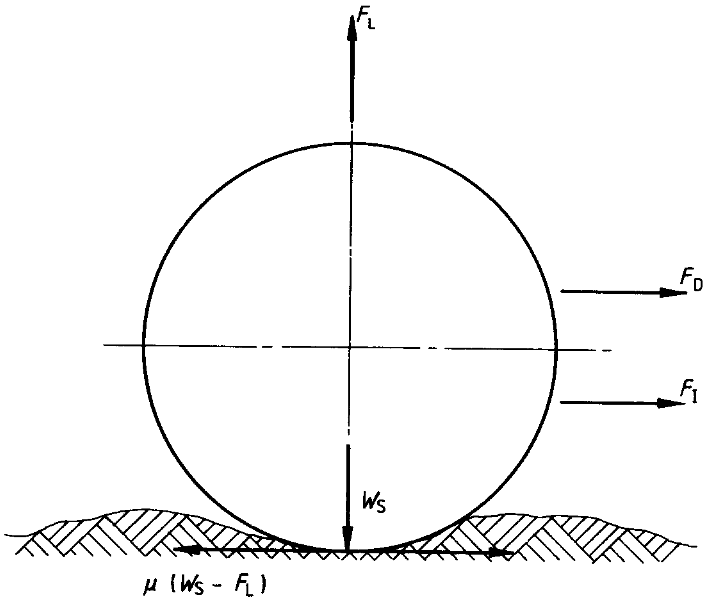

Figure 2 — Two-dimensional stability analysis approach

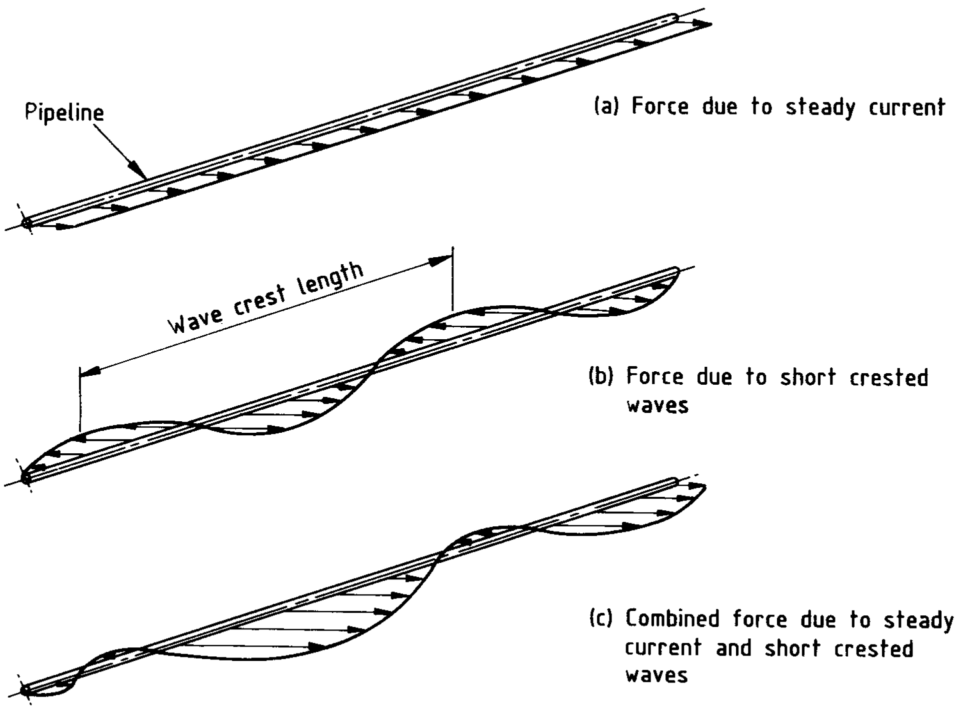

Figure 3 — Three-dimensional stability analysis approach

4.5.4.3 ***Vertical stability***

When assessing the vertical stability of a pipeline the following should be considered:

a) the specific weight of the soil;

b) the soil shear strength;

c) seabed liquefaction.

If sinking is likely to occur, then the adverse effects on the pipeline should be considered. These include the following:

1) overstressing of the pipeline due to uneven sinking;

2) obstruction of future access to the pipe.

4.5.5 Stability enhancement methods

Stability enhancement methods include the following:

a) increased wall thickness;

b) concrete weight coating;

c) trenching;

d) piled anchors;

e) concrete saddles;

f) gravity anchors;

g) suction anchors;

h) flexible mattresses;

i) grout bags;

j) rock placement;

k) artificial seaweed mats.

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

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 (Annex C);

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

8) possibility of inducing scour around and between restraints.

4.5.6 Trenching and partial burial

4.5.6.1 ***Trenching***

Trenching may 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 The effectiveness of the stability enhancement mechanisms in items a) to c) is influenced by the depth, width and side slope angle of the trench.

Analysis methods should consider these influences, with allowance being made for uncertainties in predicting the actual trench profile.

4.5.6.2 ***Partial burial***

Partial burial enhances stability by the following means:

a) increased lateral soil restraint;

b) reduction in hydrodynamic forces.

4.5.6.3 ***Self burial***

Where knowledge of seabed conditions and historical stability indicate that self burial to the required depth of cover is likely, the self burial may be utilized as a means of limiting 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, which results from sediment mobility, and pipeline sinking (see **4.5.4.3**) which results from shear failure of the seabed soil.

4.6 Spanning pipelines

4.6.1 Geometry

The geometry and support conditions which define a span should be expressed with reference to the following:

a) end support conditions;

b) length of span;

c) profile of gap below the span;

d) end slope conditions.

4.6.2 Evaluation

The span should be evaluated for the full range of loading conditions (see **4.2**), and for interference with other legitimate users of the sea.

NOTE Spans which are likely to interact should not be considered individually.

4.6.3 Static analysis

4.6.3.1 ***General***

The static analysis should consider the allowable stress, or strain, criteria identified in **4.2.4** and **4.2.5** as appropriate and the potential for lateral instability.

4.6.3.2 ***Lateral stability***

Free spans may occur either due to seabed topography, or to 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, it is essential that measures be taken to reduce the effective span length.

4.6.4 Vortex shedding and fatigue

Pipeline or riser span oscillations induced by internal or external fluid flow should be considered.

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 **4.2.8**);

d) coating integrity (see **4.12.2**).

4.7 Pipeline and cable crossings

4.7.1 Functional requirements

The design of each crossing should ensure that separation is maintained between the new pipeline and the existing pipeline or cable.

The functional requirements for each crossing are the following.

a) The weight 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 and long term settlement and overburden loads.

b) The crossing design should accommodate pipeline expansion effects.

c) The cathodic protection systems should be isolated.

4.7.2 Design considerations

4.7.2.1 ***Consultation***

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

4.7.2.2 ***Pipeline route***

The route of each new pipeline should be selected in order to achieve the following:

a) avoid the use of stacked pipeline or cable crossings;

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

4.7.2.3 ***Condition of existing system***

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

a) age and condition;

b) pipe/cable size and 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 system;

g) pipeline operating pressures and temperatures;

h) pipeline contents;

i) cable operating specification;

j) accuracy of as-surveyed data.

4.7.2.4 ***Environment***

If the existing pipeline or cable needs to be lowered, the design of the crossing should be based on the following environmental data:

a) soils description;

b) bathymetry and history of seabed mobility;

c) bearing capacity of seabed;

d) wave and current details and water depth;

e) fishing and other marine activities.

4.7.2.5 ***Lowering the existing system***

If the existing pipeline/cable needs to be lowered, a sufficient transitional length on each side of the crossing should be lowered such that pipeline bending is maintained within acceptable stress levels and pipeline buckling is prevented. (See **4.2**.)

NOTE Consideration should be given to reducing the pressure in the existing pipeline during the lowering operation.

4.7.2.6 ***Elevating new pipeline***

The design of the elevated pipeline section should minimize free spans.

4.7.2.7 ***Support structures***

Support and protective structures, ramps or separators should be designed to prevent scour.

4.7.3 Installation consideration

4.7.3.1 *Notification*

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

4.7.3.2 *Survey*

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

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

b) after crossing pipe installation;

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

4.7.3.3 *Installation tolerances*

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

4.7.4 Protection of crossings

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

4.8 Landfalls

4.8.1 General

4.8.1.1 *Extent of landfall*

The landfall extent is distinguished by the following features:

a) a different method of pipeline installation, required as a result of physical characteristics such as water depth, surf or intertidal zone conditions, topographic or geotechnical conditions or environmental impact considerations;

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

c) differing pipeline design requirements.

Certain aspects of BS 8010-2.8:1992 are also relevant to the shore area and should be consulted.

NOTE Principal methods of installation of landfalls (see **4.8.2** and **10.8**) usually include installation of the pipeline for some distance above low water mark. This clause therefore also refers to the portion of the pipeline above low water, where that portion is installed by the same method and in the same operation as the landfall.

4.8.1.2 *Applicability to short nearshore pipelines*

Guidance provided for landfalls should be considered when designing short nearshore pipelines.

4.8.1.3 *Routing*

Routing of the landfall is subject to the same general considerations as the remainder of the submarine pipeline (see **4.1.6**). Additional aspects that should be considered include the following:

a) environmental conditions caused by adjacent coastal features;

b) location of the landfall to facilitate installation;

c) feasibility of installation methods (see **4.8.2**);

d) environmental impact;

e) landline route;

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

g) consultation with appropriate statutory authority.

4.8.1.4 *Survey requirements*

Survey requirements for a landfall are similar to those for the remainder of the submarine pipeline with respect to environmental, bathymetric and geotechnical data. Additional requirements that should be considered include the following:

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

b) investigation of coastal erosion;

c) investigation of ground conditions;

d) presence of rock outcrops;

e) possible need to breach sea defence works.

4.8.2 Installation considerations

Installation methods (see **10.8**) should be considered during the design, taking account of the following:

a) self weight of the pipe;

b) loads imposed during installation;

c) period of installation.

4.8.3 Loads (see **4.2.1**)

Additional consideration should be given to the selection of a wave theory which is appropriate to the landfall zone (see Annex B). Attention should also be given to the following:

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

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

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

4.8.4 Design factors and stress evaluation

Seabed design factors shall apply for the landfall.

NOTE See also **4.2.4** and **4.2.5**.

4.8.5 Protection and stabilization

4.8.5.1 ***Pipeline protection*** (see **4.12**)

Pipelines in the landfall zone should be buried.

4.8.5.2 ***Pipeline stabilization*** (see **4.5**)

Consideration should be given in stability design to the shorter term exposure to hydrodynamic forces.

Where restraints or anchors are required (see **4.5.5**), consideration should be given to their installation in the environmental conditions prevailing in the nearshore area.

4.8.5.3 ***Burial requirements***

The burial depth should be determined such that the pipeline will not become exposed during its life. Minimum cover requirements should also be related to accidental loads (see **4.2.2.6**).

4.9 Tie-ins and risers

4.9.1 Expansion evaluation

4.9.1.1 ***Design cases for expansion and contraction***

The design should consider the effect of expansion or contraction under the following:

a) operating conditions;

b) hydrotest conditions;

c) shut-in wellhead pressure.

Methods of controlling pipeline expansion effects include the following:

1) axial anchoring systems;

2) expansion offsets;

3) containment within a sleeve (see **4.4**).

4.9.1.2 ***Seabed friction factors and soil restraint***

Where longitudinal friction factors cannot be determined from soil survey data, the minimum values given in Table B.1 should be used.

Frictional resistance to expansion may be increased by engineered backfill. The design of the backfill should give consideration to the uncertainties inherent in its method of placement.

4.9.1.3 ***Temperature changes***

The heat loss through the pipeline system should be considered when undertaking stress calculations.

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

4.9.2 Loads

4.9.2.1 ***Installation loads*** (See section **10**)

During the installation analysis, slam loads and lifting of pipe sections should be analysed.

4.9.2.2 ***Environmental loads***

Environmental loads should be treated as described in Annex A.

In addition the following loads should be considered:

a) platform displacements, including long term settlement;

b) scour effects which may occur around any structure on the seabed;

c) vortex shedding (see **4.6.4**).

Velocity amplification effects should be considered where risers are located close to structural members (see **B.1.6**).

NOTE Horizontal sections of risers in the splash zone are subject to wave slam loads.

4.9.2.3 ***Dynamic forces induced by pipeline operations***

Dynamic loads due to pipeline operations require consideration. Local loads may occur as a result of discontinuities in the flow. The combination of such loads should take account of their frequency of occurrence.

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

4.9.2.4 ***Deadweight loads***

Deadweight loads may include the weight of the following:

a) topside pipework;

b) valves;

c) any fittings in the riser system.

4.9.2.5 ***Accidental loads***

Consideration should be given to the following:

a) routing of risers (see **4.9.5.1**);

b) providing additional mechanical protection in hazardous areas.

4.9.3 Design factors and stress evaluation

Design factors and stress evaluation should be as recommended in **4.2.4** and **4.2.5** respectively.

For certain riser installation conditions, permissible strain criteria may be applied in accordance with **4.2.6**.

4.9.4 Tie-in spool design consideration

4.9.4.1 ***Flexibility***

The main purpose of the expansion spool is to limit the loads transmitted to the riser due to movement of the pipeline.

The stresses in the spool and loads transmitted to the riser are dependent on the frictional resistance of the seabed. In the absence of specific data, the values of friction factor given in Table B.1 may be used.

Where the movement of the spool is restricted, this should be considered in evaluating the spool flexibility.

4.9.4.2 ***Stability***

As it is necessary for the spool to move relatively freely, local lateral stability under environmental loading may not be achieved. Where the spool displacement is allowed to occur forces and stresses under maximum environmental conditions should be evaluated.

Vertical stability should always be assured, i.e.

$$W_s > F_L$$

where

W_s is the submerged weight of the spool (in newtons per metre);

F_L is the maximum lift force acting on the spool (in newtons per metre).

4.9.5 Riser design considerations

4.9.5.1 ***Riser location***

Risers should whenever possible be located inboard of the structure, minimizing the possibilities of damage due to impact by marine vessels and dropped objects. Risers should be routed away from accommodation facilities and safety zones. Riser location should take into account the protection recommendations in **4.12.4**.

4.9.5.2 ***Riser supports***

The following should be considered in designing riser supports and determining their locations:

a) loads in the supports and adjacent structure;

b) static stress in the riser;

c) vortex shedding (see **4.6.4**);

d) bar buckling;

e) fatigue;

f) access for inspection;

g) thermal expansion;

h) platform settlement.

NOTE Placing riser supports in the splash zone should be avoided.

4.9.5.3 ***Areas requiring special attention***

Risers are more likely than other parts of the pipeline to be subject to material loss due to erosion and corrosion. Consideration should be given to the protection of riser sections in the splash zone (see **7.4**).

The design should recognize the limitations of external inspection techniques. Areas requiring special consideration include the splash zone and areas beyond the normal operating limits of divers or remotely operated vehicles.

4.9.5.4 ***Bundled risers***

Bundled risers can be either:

a) installed in a sleeve or J-tube; or

b) connected together but uncased.

Consideration should be given to the effects of the failure of a riser on other risers or umbilicals within the bundle.

Attention should be given to inspection of the bundled risers and the need to detect leaks within the sleeve.

Interaction effects between bundled risers should be considered. These include:

1) axial expansion forces;

2) differential expansion of bundled components.

4.9.6 Fatigue of risers

Fatigue analysis of risers should be as recommended in **4.2.8**. The degree of fixity imposed by the riser supports on the riser should be assessed in the evaluation of local stresses.

4.9.7 Risers on floating installations

4.9.7.1 ***Loads***

In addition to the loads described in **4.2.2** and **4.9.2**, the riser may be subject to large tensile forces and increased movements due to riser tensioners and excursions of the floating installation.

4.9.7.2 ***Analysis***

Risers should be analysed taking account of their dynamic behaviour and the effects of in-line tensions and large deflections.

4.10 J-tubes and sleeves

4.10.1 Configuration and routing

The following should be considered in the choice of J-tube or sleeve arrangement:

a) riser support requirements;

b) possible requirements for future risers.

4.10.2 Loadings

J-tubes and sleeves should be treated as structural attachments to a fixed offshore structure.

4.10.3 Design considerations

The design of J tubes and sleeves should consider the following:

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

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

c) fatigue due to environmental and other loadings;

d) security of attachments to structure;

e) gas permeation from flexible risers;

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

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

h) the need to detect leaks.

NOTE The analysis of J-tube buckling should consider the effect of the large eccentricity present in the bend. Arch buckling theory may be employed. See Timoshenko and Gere [18].

4.11 Subsea connections and valves

4.11.1 Connection design

4.11.1.1 ***Connection types***

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

a) tee;

b) Y-piece;

c) tapping.

4.11.1.2 ***Tees***

Tees should be as recommended in **6.4**. Typical types of pipeline tees are:

a) plain tee;

b) barred tee;

c) full flow sphere tee.

The choice of plain tees should carefully consider the relative diameters of the branch and main line. The full flow sphere tee minimizes the tendency of spherical pigs to expand into or be bypassed at the tee branch. It is essential that the bars of the barred tees do not protrude into the bore of the main line and the bars should be sized and spaced to prevent interference with the pig run.

4.11.1.3 ***Y-pieces***

Connection by Y-piece allows unidirectional pigging of the main and branch pipeline. Caution should be taken with respect to the design of the internal geometry of the Y-piece to ensure that the design flow conditions can be achieved and that it can be pigged. A test programme may be required to verify the design assumptions. Both branches of the Y-piece should have the same diameter if it is to be pigged conventionally.

4.11.1.4 ***Pipeline tapping***

Pipeline tapping is a method of connection into an operational pipeline. Two techniques may be employed:

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

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

Pipeline tappings should be subjected to appropriate NDT, strength and leak testing at appropriate stages during installation.

4.11.2 Isolation

Isolation systems used during diving work are as follows.

a) *Double block and bleed valve or system:* separates high pressure hydrocarbons from diving gas at ambient pressure and constitutes the minimum acceptable barrier during hyperbaric welding operations.

b) *Single block:* separates high pressure hydrocarbon from water, or ambient pressure hydrocarbons from diving gas.

c) *Inflated barriers:* use of spheres or bladders as barriers is limited to separation of diving gas from other inert gases or water at ambient pressure.

NOTE Other barrier systems may be considered as appropriate.

4.11.3 Valve arrangements at subsea connections

The design of the valve arrangements at subsea connections should consider the following:

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

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

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

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

e) whether the main pipeline will be in operation when the branch connection is made and its operational pressure and contents.

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

g) the requirement for pressure testing, dewatering (and possibly drying) and commissioning of the branch line;

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

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

4.11.4 Valve selection (see **6.3**)

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

Subsea valve and valve control systems should be protected (see **4.12**).

4.11.5 Actuators

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

4.11.6 Pigging

The connection design should consider the following:

a) range of flow velocities;

b) pigging requirements;

c) minimum bend radius which the pigs can negotiate;

d) minimizing of variations in pipe internal diameter;

e) minimum length of straight pipe required between fittings;

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

4.11.7 Design for inspection and maintenance

The connection should be accessible for inspection. The system layout should allow access to all items requiring maintenance.

4.12 Protection consideration

4.12.1 Possible causes of damage

The following potential causes of damage should be considered:

a) dropped objects;

b) anchors, anchor chains or cables;

NOTE Heavy anchors can penetrate the seabed to a depth of several metres.

c) seabed fishing activity;

NOTE Expansion spools at tees may require protection against snagging.

d) vessel impact;

e) subsea operations; diver and submersible vehicle activity can cause abrasion and give rise to dropped objects;

f) hydrodynamic loading;

g) seabed mobility;

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

h) marine growth;

i) seismic activity;

j) snagging of control cables and umbilicals.

4.12.2 Protection methods

4.12.2.1 *General*

The following features can provide protection for pipelines:

a) concrete coating;

b) anti-corrosion coatings;

c) bundle sleeves;

d) trenching;

e) rock placement;

f) bags and mattresses;

g) protective structures;

h) artificial seaweed mats.

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

For pipeline crossings, see **4.7**.

4.12.2.2 *Concrete coating*

Concrete coatings should be as recommended in section **8**.

4.12.2.3 *Anti-corrosion coating* (see **7.3**)

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

4.12.2.4 *Bundle sleeves*

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

4.12.2.5 *Trenching and backfill*

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

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

During the trenching operation, pipeline stress and strain should be maintained within acceptable limits.

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

The design of engineering backfill should take account of the uncertainties inherent in its method of placement (see also **4.12.2.6**).

The effects on pipeline expansion should be taken into account.

4.12.2.6 *Stone placement*

The pipeline can be protected from environmental loads by covering it with suitably graded material. This will also reduce the possibility of impact and abrasion damage, but penetration of the cover is still possible. Design considerations for stone placement include the following:

a) stability of placed material;

b) sinking of placed material into the seabed, particularly where the grain size of the material exceeds that of the underlying seabed. It may be necessary to build up the protective gravel/stone cover in progressively graded layers;

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

d) dispersion of gravel or stone material during the placement operation. Dispersion may be reduced by the use of a fall pipe system.

4.12.2.7 *Grout bags and mattresses*

The design of grout bag and mattress systems should consider the following:

a) stability under environmental loading;

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

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

d) the effect of vessel motion when placing mattresses;

e) likely scour effects;

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

4.12.2.8 *Protective structures*

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

Design criteria for protective structures include the following.

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

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

c) *Clearances.* In determining clearances between the pipeline system and the structure, consideration should be given to the following:

1) settlement of the structure foundations;

2) pipeline expansion movements;

3) accidental loads;

4) access requirements for maintenance and repair.

d) *Allowable stresses.* Stresses in the protective structure should be analysed for installation load conditions (including submerged, in air and passing through the splash zone) and in-place load conditions. Suitable analyses are given in BS 5400 and BS 8110.

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

f) *Cathodic protection.* The design of the cathodic protection system of the structure should be considered in conjunction with that of the pipeline.

4.12.3 Loads on adjacent structures

Adjacent structures can be protected from loads transmitted through the pipeline by means of proprietary breakaway joints. These limit transmitted loads by allowing the pipeline to part when a predetermined force is exceeded. The design of a load limiting system should take account of the product.

4.12.4 Riser protection

Risers and associated pipework may be protected as follows:

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

b) providing a protective fender to exposed risers;

c) providing external fire/explosion protection.

4.12.5 Flange protection

Consideration should be given to the provision of profiled flange protectors to prevent snagging of cables.

4.13 Pipeline shutdown systems

4.13.1 Platform ESD valves

Platform emergency shut down (ESD) valves shall be installed in pipeline risers in accordance with SI 1989 No. 1029 [14].

4.13.2 Subsea isolation valves

Consideration should be given to the installation of subsea isolation valves where they could contribute to the safety of offshore personnel or installations.

Section 5. Pipeline materials

5.1 Steel systems

5.1.1 General

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

Low alloy steels are carbon, carbon manganese and micro-alloyed steels with a ferritic-pearlitic or ferritic-bainitic microstructure. High alloy steels are generally stainless steels with an austenitic or austenitic-ferritic microstructure.

Where the pipeline pressure containing material is to be clad, reference should be made to the influence on the pipeline's mechanical properties (see **4.2**) and the recommendations for cladding materials (see **7.4**).

5.1.2 Dimensions

5.1.2.1 ***Dimensional specification***

The following pipeline dimensions should be specified:

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

b) nominal wall thickness;

c) tolerances on diameter and wall thickness.

5.1.2.2 ***Clad pipeline***

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

5.1.3 Materials specifications

Steel pipeline material should be in accordance with the appropriate one of the following standards.

a) Carbon and alloy steel pipe should conform to API 5L 1991.

NOTE BS 3601:1987, BS 3602, BS 3603:1991, BS 3604 and EEMUA publication No. 166 [19] should be consulted for additional guidance.

b) High alloy steel pipe should conform to the appropriate standard from the following:

BS 3605:1973; API 5LC:1991;

ASTM A790M:1985; ASTM A872:1987.

Consideration should be given to the need to specify API 5L:1991 to cover requirements such as dimensions, testing and marking.

5.1.4 Material selection

5.1.4.1 ***General***

The following material properties should be selected to ensure suitability for the application:

a) chemical composition of parent pipe and longitudinal weld;

b) weldability;

c) tensile properties;

d) hardness;

e) fracture toughness and impact resistance;

f) fatigue resistance;

g) corrosion and cracking resistance.

5.1.4.2 ***Chemical composition and weldability***

The material should have a weldability adequate for all stages of manufacture, fabrication and installation of the pipe. Weld consumables should be selected to avoid the formation of anodic weld metal which can produce the selective corrosion of weld metal in corrosive environments. Consideration should be given to weldability testing of girth welds at the procurement stage.

The susceptibility of the material to hydrogen cracking due to hardness in the heat affected zone (HAZ) can be reduced by restricting the allowable value of carbon equivalent. For traditional carbon-manganese pipeline steels the carbon equivalent formula (7) should be used. BS 4515:1984 gives guidance as to the conditions required to avoid cracking when welding such steels with various carbon equivalents. For low carbon content micro-alloyed steels the formula (8) should be used as a guide to weldability, with maximum values obtained from published literature or weldability tests.

$$CE = C + \frac{Mn}{6} + \frac{Cr + Mo + V}{5} + \frac{Ni + Cu}{15} \qquad (7)$$

$$CE = C + \frac{Mn}{20} + \frac{Mo}{15} + \frac{Ni}{60} + $$

$$+ \frac{Cr}{20} + \frac{V}{10} + \frac{Cu}{20} + \frac{Si}{30} + 5B \qquad (8)$$

The hydrogen induced cracking (HIC) resistance of pipeline steels for sour service should be demonstrated by testing in accordance with NACE TM 0284:1984. However, the Vickers hardness test may be used with the appropriate correlation for carbon manganese steels. It should not be used for stainless steels.

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

In the case of ferritic/austenitic stainless steels the phase ratio should be controlled so as to ensure compatibility between the base material and welding consumables. It is recommended that tests should be carried out to demonstrate that the corrosion resistance of the heat affected zone and weld metal matches the parent material and is adequate for service.

NOTE NACE MR 01 75 gives recommendations on materials for use in a sour service environment to prevent sulphide stress corrosion cracking (SSCC).

5.1.4.3 *Tensile properties*

The chosen material specification should specify the minimum yield strength, ultimate tensile strength and elongation.

Tensile testing should be carried out in accordance with the appropriate steel specification. If the degree of hazard imposed by the product nature and service conditions dictate that additional testing is required then more appropriate testing requirements should be specified.

5.1.4.4 *Hardness*

A material exposed to sour service conditions should comply with NACE-MR 01 75:1984. The preferred method to determine material hardness is the Vickers hardness test in BS 427:1990, utilizing a 5 kgf or 10 kgf load.

The HAZ hardness can be limited by specifying a reduced carbon equivalent or by pre- or post-weld heat treatment.

5.1.4.5 *Fracture toughness*

The material's fracture toughness properties should be based on the product, service conditions and avoidance of a propagating fracture.

Charpy testing. The toughness of both the base material and the weld seam should be determined by the Charpy V-notch impact test carried out in accordance with BS EN 10045-1:1990. Test specimens should be taken with their longitudinal axis transverse to the principal rolling/working direction. Full size specimens should be used. Where subsize specimens have to be used the reduction factor given in Table 2 should be applied.

The required energy levels (in joules) to prevent ductile fracture initiation should be either the specified minimum yield stress (in N/mm^2) divided by 10 or 27 J whichever is the higher. Where operating conditions are such that low temperatures can be reached, then special consideration should be given to brittle fracture propagation. The testing temperature should be selected in accordance with Table 3.

Consideration should be given to testing at a range of temperatures to obtain a Charpy impact transition curve.

Crack tip opening displacement (CTOD) testing. For category C and D substances see BS 8010-2.8:1992. It may be necessary to supplement the Charpy testing with CTOD testing carried out in accordance with BS 7448-1:1991. Data from the CTOD test (if necessary) should be used to establish fracture control limits and to perform an engineering critical assessment (ECA) for a known, or postulated, future defect.

NOTE Guidance on carrying out ECAs is contained in PD 6493:1991.

Other testing. Consideration should be given to other techniques such as J-integral, wide plate testing or drop weight tear testing.

Table 2 — Energy reduction factor for subsize specimens

Specimen section mm	Energy reduction factor
10 × 10	1.00
10 × 7.5	0.83
10 × 5	0.67

Table 3 — Parent material impact testing temperature

Nominal wall thickness mm	Testing temperature °C		
	Riser Category A, B, C and D	Seabed Category C and D	Seabed Category A and B
20 or less	$T_d - 10$	$T_d - 10$	T_d
20 to 30	$T_d - 20$	$T_d - 10$	T_d
over 30	To be established in each case		

NOTE 1 See BS 8010-2.8 for substance categorization.
NOTE 2 T_d is the design temperature.
NOTE 3 The nominal wall thickness should not include corrosion allowance.
NOTE 4 The maximum impact testing temperature should be + 20 °C.

5.1.4.6 *Fatigue*

Where the mechanical design has identified fatigue loadings, analysis should be based upon fracture mechanics methods (see PD 6493:1991) or methods utilizing fatigue testing (S-N curve) data. Fatigue testing should be carried out in accordance with BS 3518.

Consideration should be given to specifying materials with high Charpy impact values to enhance resistance to crack propagation. The weld NDT specification should include limitations on initial defect sizes.

5.1.4.7 ***Corrosion and cracking resistance***

If steel selection is the chosen method of internal corrosion control, the pipe material should be resistant to attack from the product and additives over the full range of operating temperatures, pressures and flow rates. (See **7.2**.)

5.2 Flexible pipes and hoses

5.2.1 Selection

The following principal components should be considered:

a) the lining, i.e. that part of the pipe that contains the product;

b) the load bearing elements, i.e. those parts of the pipe designed to accommodate stresses within the pipe wall;

c) the outer cover, i.e. that part of the pipe affording protection from the external environment;

d) the end fittings, i.e. rigid terminations at each end of the flexible pipe.

Further components that should be considered are:

1) buoyancy material (in a floating pipe or hose);

2) external armour wire.

5.2.2 Application

Requirements for typical applications are as given in the following references.

a) *Oil loading hoses* (floating and submarine). These hoses should be designed and constructed in accordance with the OCIMF Hose specifications [20].

b) *Flexible pipelines and jumper hoses* for carrying oil and gas should generally be in accordance with API RP 17B:1988.

c) *Small bore hoses* carrying hydraulic fluids, additives, service fluids etc. either in a bundle, in a carrier pipe, in an armoured umbilical or strapped to a pipeline. These hoses should be constructed as specified in one of the following British Standards: BS 1102:1991; BS 3832:1991; BS 4089:1989; BS 4586:1984; BS 4749:1991; BS 4983:1984; BS 5119:1980; BS 5780:1979.

The outer cover of the hose should be suitable for permanent immersion in seawater (unless contained within a dry carrier pipe or a sheath).

NOTE 1 A range of proprietary designs exist for flexible pipes and hoses, with varying materials and construction details.

NOTE 2 It should be ensured that the specification of the flexible pipe or hose, whatever its method of construction, is acceptable for its intended purpose.

5.2.3 Construction

5.2.3.1 ***Fabrication***

For flexible pipes and hoses not conforming to any of the standards in **5.2.2**, the size of flexible pipes should be specified in terms of internal diameter. The diameter chosen, including tolerances, should take into account the following:

a) the diameter sizes and range of pipe lengths available;

b) the range of design pressures available for each size;

c) the diameter of the remainder of the pipeline system and the degree of mismatch allowable.

Outside diameter may be restricted by the following:

1) dimensional constraints imposed by the pipe routing (e.g. the inside diameter of a J-tube);

2) pipeline on-bottom stability, buoyancy forces and hydrodynamic forces (see **4.5**).

NOTE The outside diameter of a flexible pipe for a given bore and pressure rating varies between manufacturers.

5.2.3.2 ***End fittings***

The internal diameter of end fittings where pigging is required should be similar to that of the flexible pipe. Other end fitting dimensions are dictated by the particular manufacturer's design, with the following exceptions.

a) Dimensions of flanged and other pipeline connectors integral with the end fitting should be as stated in section **6**.

b) Weld end bevels for connecting end fittings to adjacent pipeline components should be as stated in BS 4515:1984.

c) End couplings for small-bore hoses should conform to BS 1906:1952 or BS 4368.

5.2.3.3 ***Length***

The lengths of individual subsea and floating hoses for single point moorings should match the standard lengths quoted in OCIMF Hose specifications [20].

No standard lengths exist for other applications. The chosen uninterrupted length of flexible pipe or hose should take into account the following:

a) the probability and consequences of leaks at intermediate joints;

b) the effect of intermediate joints on the weight and flexibility of the pipe during installation and service;

c) diameter dimensional constraints;

d) restrictions imposed by the process of manufacture.

5.2.4 Materials specifications

5.2.4.1 *Non-metallic pipe components*

The specification of the grade and thickness of non-metallic materials of the flexible pipe wall should take account of the following:

a) knowledge of proprietary designs of pipe;

b) the pipe performance specification (see **4.3.5**);

c) compatibility with:

1) product and any additives at service temperature;

2) hydrotest medium;

3) marine environment;

d) resistance to fire or mechanical damage during installation or service.

5.2.4.2 *Metallic pipe components*

Metallic components within the lining of the pipe should be fabricated from wire, strip or other thin section and should be of a material compatible with all products and additives at the conditions to which they may be exposed, taking into account gas permeability.

NOTE Guidance on materials selection is given in BS 1441:1969, BS 1475:1972, BS 3592-1:1986 and BS 3592-2:1986 and NACE MR 01 75.

5.2.5 Materials selection

The design information required for the selection of the materials and fabrication of flexible pipes, hoses and end fittings is similar to that required for steel pipeline materials selection as stated in **5.1.4**.

The type of service, design life, bore size and working pressure should determine the basic type of flexible fabrication that will be offered by manufacturers. The fabrication should be modified if necessary in order to accommodate the following:

a) any additional mechanical requirements for the following:

— submerged weight;

— fatigue resistance;

— vacuum resistance;

— resistance to external pressure;

— tensile strength;

— stiffness;

— minimum bend radius.

b) materials changes necessitated by likely degradation by the product being carried or by the external marine environment;

c) materials changes necessitated by possible galvanic corrosion between contacting dissimilar metals in an internal or external aqueous environment;

d) materials changes necessary to prevent or restrict the escape of product through the pipe wall, such as permeation by product gas.

Section 6. Pipeline fittings and equipment

6.1 General

6.1.1 Introduction

This section covers ratings, dimensions and selection of material for pipeline fittings (including bends, reducers, branches, valves, gaskets, flanges and closures) and other pipeline related equipment.

6.1.2 Ratings

Fittings should be selected by pressure rating, in accordance with the standardized system of pressure ratings in BS 1560-3.1:1989 or ANSI B16.5:1988. The temperature of the product should be taken into account in determining an acceptable pressure rating.

6.1.3 Materials selection

The selection should be based on the same properties as considered for line pipe in **5.1.4** and the suitability of the materials for particular requirements such as the following:

a) compatibility with linepipe;

b) compatibility with product at service temperature;

c) compatibility with product additives at service temperature;

d) compatibility with hydrotest medium and additives;

e) compatibility with seawater, marine growth and marine atmosphere;

f) resistance to abrasion or other mechanical damage likely during installation or service.

In the case of fittings or equipment which contain components in dissimilar metals, consideration should be given to the prevention or control of galvanic corrosion between these metals. Special consideration should be given to areas where corrosive substances may accummulate or where chemical inhibition may be ineffective.

6.2 Flanged connections

6.2.1 Flanges

Flange connections should take account of the following:

a) pressure and temperature requirements;

b) accessibility;

c) applied axial bending and torsional loads (including installation loads);

d) methods of bolt tightening.

Flanges should comply with one of the following:

— BS 1560-3.1:1989 (nominal pipe size 1/2 in to 24 in);

— BS 3293:1960 (nominal pipe size 26 in to 48 in);

— BS 4504-3.1:1989 (nominal pipe size 6 mm to 400 mm);

— ANSI B16.5:1988 (nominal pipe size 1/2 in to 24 in);

— MSS SP-44:1991 (nominal pipe size 1/2 in to 60 in).

Proprietary flange designs are permissible. These should conform to the relevant sections of pressure vessel standards such as BS 5500:1991 or ASME VIII-1:1992.

The gaskets should be selected in accordance with the relevant flange standard and service conditions.

6.2.2 Bolting

Bolts, studbolts and nuts used for joining flanges, or as components in valves and other fittings, should be selected according to BS 4882:1990, or ASTM A193:1990 or ASTM A194:1990 giving due consideration to service temperature, load requirements and corrosion resistance.

NOTE Where no suitable bolting is specified in BS 4882 or ASTM A193 or ASTM A194, the specification for the fitting or the manufacturer may be consulted for guidance.

The specification of materials fracture toughness and hardness, to prevent brittle fracture of high strength bolting, should be considered if the bolting is to be exposed to corrosive conditions or cathodic protection.

6.3 Valves

6.3.1 Valve selection

Valve selection should include consideration of the following service characteristics:

a) system operating and hydrostatic pressure;

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

c) service temperatures (this may include low internal temperatures due to system depressurization);

d) service life;

e) duration of precommissioning period (valves may remain static in open or closed positions for long periods but have to be able to function on demand);

f) presence of debris from product or construction activities;

g) system pigging;

h) insitu seal injection or replacement;

i) installation method;

j) ability to test the valve performance;

k) internal galvanic corrosion;

l) reliability;

m) maintenance aspects;

n) actuation.

NOTE Reference may be made to the following standards:

1) BS 5351:1986 (ball valves, nominal size 8 mm to 400 mm);
2) BS 5353:1989 (plug valves, nominal size 8 mm to 100 mm);
3) BS 1868:1975 (check valves, nominal size 15 mm to 600 mm);
4) BS 1414:1975 (wedge gate valves, nominal size 15 mm to 600 mm plus 650 mm to 1 050 mm limited);
5) BS 1873:1975 (globe valves, nominal size 15 mm to 400 mm);
6) BS 5352:1981 (wedge gate, globe and check valves, nominal size 8 mm to 50 mm);
7) ASME VIII-1 (gate valves, nominal size 50 mm to 150 mm);
8) BS 6755-1 and BS 6755-2 (inspection and test of valves manufactured to BS 1414, BS 1868 and BS 5351). API 6D is permissible as an alternative to British Standards for the following classes of valve:
   — plug valves, size 2 in to 36 in;
   — ball valves, size 2 in to 60 in;
   — check valves, size 2 in to 60 in;
   — gate valves, size 2 in to 60 in.

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

6.3.2 Control of valves

Control system selection and design should include consideration of the following:

a) type of actuator;

b) valve function;

c) required response time;

d) distance from control source.

e) specification of secondary control systems for emergency isolation valves.

6.4 Other pipeline fittings

Other pipeline fittings include special connectors, bends, tees, Ys, end caps, reducers and cast or forged transition pieces.

NOTE Guidance on the fabrication of fittings is contained in BS 1640 and MSS SP 75.

The face-to-face dimension of flanged fittings may need to be increased from that stated in the appropriate standard when required to accommodate specialist bolt tightening equipment.

6.5 Bends made from pipe

6.5.1 Methods of manufacture

Bends made from straight pipe should be hot bent, cold bent or induction bent. It is essential for pipeline integrity that mitre bends are not used.

6.5.2 Pipe properties

Because the properties of a completed bend may differ significantly from those of the straight pipe from which it is made, the bend should be demonstrated to possess properties compatible with the requirements of the design of the pipeline system. If necessary, test bends should be produced for destructive testing purposes.

6.5.3 Dimensions

Dimensions and tolerances of the ends of the bend cross section should be compatible with those of the adjoining straight pipe to facilitate joining. If necessary this may be achieved by the inclusion of straight tangent sections at either or both ends of the bends.

Ovality of cross section should be restricted such that the bore diameter is reduced by no more than 2.5 % of the nominal value at any point along the bend; more severe restrictions may be required if inspection vehicles or well tools are to be used in the line.

If the wall thickness falls below the minimum specified for the pipeline, the bend should be rejected. An allowance should be made for thinning of the parent pipe during bending.

Longitudinal welds should be positioned on the neutral axis of the bend.

Wrinkling of the pipe surface should not be permitted.

6.6 Pig traps and closures

Pig traps, which form part of the riser system, should be designed as recommended in section **4** using a design factor equal to that required for the riser itself. The design, fabrication and inspection of closures and details such as nozzle reinforcements, saddle supports and other items not classed as standard pipeline sections should comply with BS 5500:1991 or ASME VIII-1:1992.

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

The pig trap should be oriented towards the open sea and adequate space and facilities should be provided to open the closure and load/unload pigs.

6.7 Slug catchers

6.7.1 Vessel-type slug catchers

All vessel-type slug catchers, wherever they are located, should be designed in accordance with BS 5500:1991 or ASME VIII-1:1992.

6.7.2 Multi-pipe slug catchers

Multi-pipe assemblies which form part of the riser system should be designed accordingly (see **4.9**), with the limiting hoop stress equal to that required for the riser itself.

6.8 Other pressure-containing parts

Other pressure-containing parts should be designed with reference to BS 5500:1991 or ASME VIII-1:1992.

Section 7. Corrosion

7.1 Corrosion control design approach

7.1.1 External corrosion

7.1.1.1 ***General***

The design of a system to control external corrosion should take into account the following:

a) pipeline system;

b) design life (see **1.3.2**);

c) operating temperature range;

d) pipeline installation method;

e) environmental conditions (including soil properties);

f) presence of bacteria;

g) adjacent structures and cathodic protection systems.

Consideration should be given to a corrosion allowance if any corrosion of the pipeline is anticipated.

7.1.1.2 ***Available techniques***

The following techniques should be considered for control of corrosion:

a) external coating;

b) external cladding;

c) corrosion-resistant pipe;

d) cathodic protection;

e) chemical inhibition of environment (e.g. for a pipeline or risers inside a closed caisson or sleeve pipe).

7.1.1.3 ***Selection of techniques***

The choice of techniques employed for a corrosion protection system should be determined by the following:

a) effectiveness in preventing or controlling the corrosion mechanisms;

b) requirement for installation, inspection and maintenance of the system;

c) reliability of operation over the life of the pipeline and consequences of protection systems failure or damage;

d) pipeline installation techniques;

e) application of weight coating.

The type of corrosion protection employed may vary for different parts of the pipeline.

7.1.2 Internal corrosion

7.1.2.1 ***General***

The design of a system to control internal corrosion should take into account the following:

a) pipeline system and lining materials;

b) design life;

c) product composition throughout design life;

d) operating temperature range;

e) operating pressure range;

f) flow characteristics;

g) pipeline pigging.

Consideration should be given to a corrosion allowance if any corrosion of the pipeline is anticipated.

7.1.2.2 ***Available techniques***

The following techniques should be considered for the control of corrosion:

a) corrosion-resistant line pipe and welding materials;

b) internal cladding (with corrosion-resistant alloys);

c) internal lining (with non-metallic coating);

d) product composition control;

e) chemical inhibition;

f) operational pigging.

7.1.2.3 ***Selection of techniques***

The choice of corrosion control techniques can be influenced by the following factors:

a) effectiveness in protection or control of the corrosion mechanisms;

b) reliability of operation over the life of the pipeline;

c) accessibility of the pipeline (for monitoring purposes);

d) ability to monitor internal corrosion;

e) ability of pipeline to pass inspection pigs.

7.2 Material corrosion and erosion

7.2.1 External attack on pipeline systems

7.2.1.1 ***Atmospheric corrosion***

Atmospheric corrosion of pipes can occur in two instances:

a) before installation (during transport or storage of pipes);

b) in the atmospheric zone of risers.

Dry storage and temporary rust preventatives to control corrosion of pipes during storage should be considered. Atmospheric corrosion of risers should be controlled by application of a coating.

7.2.1.2 ***Aqueous corrosion***

For uncoated pipe the rate of attack is dependent on the following:

a) metal surface temperature;

b) salinity of the water;

c) aeration of the water;

d) pipe material;

e) velocity of water;

f) pH of water;

g) suspended matter in water;

h) biofouling properties of water.

Protection of pipes from aqueous corrosion should be provided through coating, cladding, cathodic protection or the use of sleeves filled with chemically inhibited water or an inert medium.

Particular attention should be paid to the protection of risers in the splash zone.

7.2.1.3 ***Attack in the presence of chlorides***

The presence of chloride ions enhances the following:

a) rate of attack on carbon and microalloyed steels;

b) pitting and crevice corrosion of stainless steels;

c) stress corrosion cracking of stainless steels under stress (see **7.2.2.5**).

Consideration should be given to application and maintenance of coatings to prevent chloride attack on carbon steels.

Consideration should be given to minimizing localized attack on stainless steels by the following techniques:

1) avoidance of crevices in steel surfaces and joints at the pipeline design stage, supplemented by avoidance of crevices during the fabrication stage;

2) selection of resistant materials;

3) cathodic protection;

4) eliminating or minimizing coating holidays;

5) avoidance of contamination with carbon steel (e.g. weld spatter, steel filings).

7.2.1.4 ***Microbial corrosion***

The potential for sulphide stress cracking (SSC) and general corrosion (see **7.2.2.4**) should be considered if sulphate reducing bacteria (SRB) are present. Cracking may be prevented by the following:

a) selection of resistant materials;

b) limitation on weld and base metal hardness (see **5.1.4.4**);

c) external coating.

NOTE Other micro-organisms may cause crevice corrosion or corrosion beneath deposits.

7.2.1.5 ***Marine growth*** (see **7.3.3.10**)

Marine growth may cause crevice corrosion or may hide or enhance existing corrosion. Consideration should be given to the application of an anti-fouling coating or mechanical removal.

7.2.1.6 ***Effects of elevated temperature***

Consideration should be given to the effect of temperature on all corrosion processes. Attention should be paid to additional corrosion mechanisms likely to occur at elevated temperatures which do not occur at lower temperatures. High temperatures will affect the choice of corrosion coating and anode material.

7.2.2 Internal attack on steel pipeline systems

NOTE See Smith and De Waard [21]; Smith, De Waard, Simon and Thomas [22]; Milliams [23]; De Waard and Milliams [24]; Milliams and Kroese [25]; and Van Gelder [26].

7.2.2.1 ***General***

The product being transported should be considered potentially corrosive if it contains any of the following:

a) free water;

b) oxygen;

c) hydrogen sulphide;

d) carbon dioxide;

e) acids;

f) bacteria;

g) chlorides.

If more than one of these agents is expected, their possible interaction should be investigated.

The evaluation of corrosivity should take into account all products or combinations of products that will flow through the pipeline throughout its design life.

In systems containing multi-phase mixtures of water and liquid hydrocarbons, the degree of corrosivity will be influenced by whether the pipe walls are water-wet or oil-wet. This should be determined from the proportion of water and the flow regime present.

Pipes and valves can corrode internally through stagnant, contaminated water before and after installation or at shut downs. Precautions to dry out pipelines after hydro-testing and to prevent ingress of water are therefore necessary.

7.2.2.2 ***Aqueous corrosion***

Aqueous corrosion of carbon and microalloyed steels should be considered likely if in contact with water containing an acid or a cathodic reactant such as oxygen. Both uniform and pitting corrosion are possible.

NOTE Certain stainless steels and nickel-based alloys are resistant to aqueous corrosion but only in the absence of chloride ions (see **7.2.2.5**).

7.2.2.3 ***Corrosion by carbon dioxide***

Corrosion of carbon and microalloyed steels should be considered if carbon dioxide and water are present. Both general and localized corrosion will occur, the rate depending on temperature, partial pressure of carbon dioxide, flow characteristics and the presence of other corrodents and inhibitors.

Certain stainless steels are more resistant to carbon dioxide corrosion than carbon and microalloyed steels.

7.2.2.4 ***Corrosion by hydrogen sulphide*** *(H_2S)*

If H_2S and free water are present in a pipeline the following types of corrosion are possible and should be taken into account in the design.

a) Microalloyed steels are subject to uniform or pitting corrosion.

b) SSC may occur in high strength steels and hard areas of low strength steels if the product contains certain quantities of H_2S. Such products are known as sour.

NOTE 1 For further information on SSC see NACE MR 01 75.

c) HIC may occur in carbon and microalloyed steels. The susceptibility of materials to HIC is determined by their micro structure, inclusion morphology and chemical composition. The resistance of a steel to HIC may be improved by a range of techniques which includes, but is not limited to, reducing the sulphur content, reducing the manganese content, the addition of calcium or rare earth metals to the melt, selection of an appropriate heat treatment regime.

NOTE 2 NACE TM 01 77 and TM 02 84 give guidance on testing for HIC resistance.

7.2.2.5 ***Corrosion in the presence of chlorides***

The following forms of attack should be considered in the presence of chloride ions in water:

a) accelerated aqueous corrosion of carbon and microalloyed steels;

b) crevice corrosion and pitting of stainless steels especially at elevated temperatures;

c) stress corrosion cracking of austenitic stainless steels under tensile stress at temperatures above approximately 60 °C.

7.2.2.6 ***Microbial corrosion***

The presence of bacteria or other micro-organisms in a pipeline containing water should be considered likely to give rise to the following corrosive attacks on all types of steels:

a) corrosion through the formation of deposits under which selective dissolution of steels may occur;

b) corrosive attack by H_2S released by certain species, as outlined in **7.2.2.4**.

7.2.2.7 ***Erosion***

Pipe materials may be susceptible to erosion, either by suspended solids or by impinging liquids.

The velocity, V_e, above which erosion by fluids should be considered is given by the following equation:

$$V_e = \frac{m}{(\rho_m)^{½}} \tag{9}$$

where

V_e	is fluid erosional velocity (in metres per second);
ρ_m	is fluid density (in kilograms per cubed metre);
m	is a constant taking values from 152.5 (for intermittent service) to 122 (for continuous service).

NOTE These values of *m* are considered conservative, and higher values may be used if service experience and/or experimental studies show them to be justified. However, the value of *m* may need to be reduced if solid erosion (by sand) or erosion corrosion (see **7.2.2.8**) are expected. Reference may be made to API RP 14E.

7.2.2.8 ***Erosion corrosion***

Erosion corrosion of the pipe wall should be considered when either corrosion protection products or protective coating may be removed by impinging liquid or solids.

7.2.2.9 ***Scale formation***

Accelerated corrosion should be considered likely under scale. If scale is liable to form, the use of a scale inhibitor (see **7.5.2.5**) or descaling agents should be considered.

7.2.2.10 ***Combinations of corrosive agents***

If an environment contains a combination of corrosive agents the severity of attack may be increased from the type of attack from a single agent. Under these circumstances practical evidence of material suitability for use with a particular product at its service temperature should be sought.

7.2.3 External attack on flexible pipes

It should be demonstrated that flexible pipe is fit for service in the relevant environment, through compatibility tests involving the proposed flexible pipe cover material. The following service conditions should be considered:

a) splash zone;

b) immersion in seawater;

c) burial in seabed or platform debris;

d) coverage by marine growth;

e) immersion in water with chemical additives (e.g. inhibited seawater inside a J-tube or sleeve pipe);

f) spillage of hydrocarbon product.

End fittings of flexible pipes may be subject to the same forms of attack as those outlined in **7.2.1** and protection should be considered in a similar manner.

7.2.4 Internal attack on flexible pipes

It should be demonstrated that flexible pipes are fit for carrying the product fluid, including any other fluids specially introduced during pipeline installation, commissioning or service life.

For non-metallic materials within the body of the pipeline, fitness for service should be demonstrated by either previous service history or through compatibility tests involving the material and proposed product. The following factors relating to service conditions should be considered:

a) product liquid and gas composition;

b) product additives, e.g. corrosion inhibitors and demulsifiers;

c) hydrotest medium, including any additives, and duration;

d) temperature and pressure regimes for pipeline contents;

e) continual or infrequent flexing of the pipeline;

f) complete or partial decompression of the pipeline;

g) marine atmosphere (e.g under storage or after dewatering).

Metallic materials in the bore of the pipe, such as the end fittings or continuous internal metal spirals, may be subject to the same forms of internal attack as those outlined in **7.2.2**. In addition any metallic materials within the pipe wall to which gaseous components of the product may diffuse, or to which liquid ingress may occur, may be subject to attack, e.g. by "wet" H_2S on stressed steel reinforcement wires. The possibility of such attack should be eliminated in the design of the pipe by one or a combination of the following means:

1) control of the degree of permeability of the pipe bore liner and successive layers of pipe wall material;

2) elimination of paths for ingress of liquids into the pipe wall, either from the bore of the pipe or from the outside environment;

3) selection of metallic materials resistant to the types of degradation liable to arise from the service conditions.

7.2.5 Corrosion allowance

If corrosion control measures are unable to control the integrity of the pipeline over its design life then provision of a corrosion allowance should be considered.

Where a corrosion allowance is used to combat predicted corrosion, a means of demonstrating that the required wall thickness remains is essential.

NOTE The provision of a wall thickness greater than that required for construction or operational reasons is common practice and provides some safeguard should unexpected corrosion or other damage occur.

7.3 Non-metallic coatings and linings

7.3.1 Coating selection considerations

When selecting coatings the following should be considered:

a) environment to which the pipe will be exposed (from fabrication through to end of service life);

b) temperatures to which pipe is exposed;

c) available means of application (e.g. site or mill application);

d) exposure to damp;

e) means and ease of inspection and repair;

f) extent of coating breakdown throughout design life;

g) pipe installation method.

7.3.2 Surface preparation

7.3.2.1 ***General***

Good surface preparation is essential to satisfactory coating performance. General guidance for all aspects of surface preparation is given in BS 5493:1977.

7.3.2.2 ***Degreasing***

Deposits of oil and grease on the steel surface should be removed by solvent cleaning. Cleaning should comply with the requirements of SSPC-SP-1-63 1982.

7.3.2.3 ***Blast cleaning***

Blast cleaning of carbon and microalloyed steel should be carried out in accordance with SSPC-SP-10-63T 1989.

7.3.2.4 ***Abrasive materials***

Guidance on available abrasive particles suitable for blasting is given in Table 6 of BS 5493:1977 (see also BS 245:1976). Sand blasting should not be applied.

7.3.2.5 ***Power tool and hand cleaning***

Supplementary cleaning (in addition to that achieved by blast cleaning, or for small areas of steel) should be carried out by power or hand tools. The procedure should comply with SSPC-SP-3-63 1989 (for power tools) or SSPC-SP-2-63 1989 (for hand tools).

7.3.2.6 ***Pickling***

Where used as a substitute for blast cleaning, pickling should comply with SSPC-SP-8-63 1982. After pickling, all acids and deposits should be rinsed off the pipe before the coating proceeds.

7.3.2.7 ***Standards of cleanliness***

The standard of cleanliness after preparation should be judged in accordance with BS 7079, or with SIS-05-59-00:1967. The quality of finish required should be specified.

7.3.2.8 ***Surface profile***

Surface roughness should be specified with due consideration to the thickness of subsequent coating, and its adhesion to steels. Methods of measuring profile should be as recommended by BS 7079.

7.3.2.9 ***Stainless steel surfaces***

Non-ferrous abrasives only should be used to prepare stainless steel surfaces. A first quality finish in accordance with BS 7079 and a high surface profile are required to ensure good coating adhesion.

NOTE In the presence of chlorides, high profile surfaces may promote crevice corrosion.

7.3.2.10 ***Coating delay***

The maximum allowable time between preparation and coating should be stated taking into account humidity and pipe temperature.

7.3.3 External pipe coating materials

7.3.3.1 ***Coating selection***

The properties required of a coating may vary along the pipeline and several types of coating may be required. When selecting each coating system, the following should be considered:

a) resistance to moisture penetration;

b) electrical resistivity;

c) ease of application and repair;

d) integrity of coating;

e) adhesion;

f) resistance to damage;

g) resistance to weathering;

h) compatibility with weight coating;

i) flexibility;

j) toxicity to marine life;

k) resistance to cathodic disbondment;

l) suitability at operating temperatures;

m) resistance to biofouling;

n) resistance to ultraviolet light;

o) thermal insulating properties;

p) resistance to slippage.

Coating materials and application methods should be prequalified if they are not covered by a British Standard.

7.3.3.2 ***Reinforced bitumen and coal tar enamels***

Bitumen (asphalt) based materials and primers should conform to BS 4147:1980. Coal tar based materials and primers should conform to BS 4164:1987. Adequate procedures should be used during handling and application where the materials have carcinogenic properties.

Application may be carried out on site or at coating mills.

Solar protection, e.g. whitewash, should be used to protect the coating from damage that may be caused by direct sunlight or heat.

7.3.3.3 ***Cold-applied tape wraps and shrink sleeves***

Cold-applied tape wraps and shrink sleeves should be considered for the following applications:

a) field joint coating;

b) added protection of pre-coated pipes;

c) coating of short lengths of pipe or fittings.

7.3.3.4 ***Polyethylene***

Polyethylene coatings on pipe may be made of high density or low density grades, or a mixture of the two.

Polyethylene coatings applied by sintering or extrusion should meet the requirements of DIN 30 670.

7.3.3.5 ***Epoxy and associated systems***

Applications of epoxy may be carried out by one of the following methods:

a) spraying of powder onto heated pipe (i.e. fusion bonding);

b) use of a two-pack epoxy or urethane liquid system, normally cured at ambient temperature.

7.3.3.6 ***Elastomers***

Polychloroprene and related elastomers provide a coating of high integrity and resistance to mechanical damage when suitably compounded and vulcanized.

7.3.3.7 ***Polypropylene***

Polypropylene coatings may be applied by extrusion on to steel pipes that are normally precoated with epoxy resin.

7.3.3.8 ***Paint systems***

Parts of risers, J-tubes, spool pieces and piping, whether submerged, in the splash zone or above water, may be suitable for painting using solvent-based or chemically cured paint systems. Guidance on acceptable systems is given in parts 3, 9, 10, 13 and 14 of Table 3 of BS 5493:1977. BS 5493 also provides guidance on application and inspection of paint systems.

7.3.3.9 ***Polymer cement coatings***

Polymer cement coatings may be used to provide mechanical protection to thin film anti-corrosion coatings. They generally consist of a polymer-modified cement mortar reinforced with glass fibres.

7.3.3.10 ***Anti-fouling coating***

Anti-fouling coatings are generally applied over anti-corrosion coating and may consist of the following:

a) paint which is toxic to marine life;

b) copper or copper alloy particles dispersed in coatings.

The environmental effects of any anti-fouling compound should be considered.

NOTE Organotin compounds have been banned for certain marine uses.

7.3.4 Internal pipe lining material

7.3.4.1 ***Selection***

Selection of internal lining materials should be based on the following factors:

a) product corrosivity and compatibility with lining;

b) pipeline design life;

c) pigging programme;

d) wear rate;

e) integrity;

f) resistance to blistering under gas decompression;

g) pipeline construction method;

h) available lining application methods (including at field joints);

i) inspection and repair.

Lining materials and application methods should be prequalified if they are not covered by a British Standard.

In the absence of reliable methods for the measurement of lining integrity during service it is not recommended that an internal lining be used as the sole means of protection against internal corrosion.

7.3.4.2 ***Cement mortar***

Cement mortar linings may be used in carbon or microalloyed steel pipes for carrying salt, fresh or waste water. Centrifugal application methods should be used, as given in BS 534.

7.3.4.3 ***Resin linings***

Epoxy, phenolic, epoxy-phenolic and urethane linings are available, and a choice between them should be made as recommended in **7.3.4.1**.

Stoved or cold-cured resins should be applied and inspected as specified in BS 6374-3:1984 and BS 6374-4:1984.

For mill-applied lining, consideration should be given to the protection of field joints.

7.3.5 Coatings and linings for flanges and fittings

Selection should be similar to that for the line pipe. Because of turbulence at bends, internal lining quality or thickness may need to be higher than for line pipe.

NOTE Fluoroplastics may be used for the coating of nuts and bolts, providing both lubrication and corrosion protection.

7.3.6 Field joint coating

7.3.6.1 ***Coating selection***

When selecting a coating the following should be considered:

a) compatibility with the construction method;

b) good adhesion of coating to pipe and existing coating;

c) resistance to heat;

d) resistance to the subsea environment;

e) compatibility with cathodic protection system;

f) resistance to installation loads (particularly of infill materials);

g) toxicity to marine life;

h) impact resistance;

i) maintenance of overall diameter;

j) compatibility of coating and infill materials;

k) inspection and repair during application.

7.3.6.2 ***Tape wraps***

Some self-adhesive tapes are suitable for offshore application.

7.3.6.3 ***Heat-shrinkable sleeves***

Heat-shrinkable sleeves and wraps are also suitable for offshore use.

7.3.6.4 ***Mastic infill***

Consideration should be given to the following:

a) temperature range for the mastic before pouring;

b) cooling of the joint before the pipe is laid;

c) effects on primary anti-corrosion coating.

7.4 Metallic coatings and claddings

7.4.1 Metallic coatings

7.4.1.1 ***Selection***

Consideration should given to the following for the selection of metallic coating:

a) corrosivity of the environment;

b) service temperatures;

c) design life.

7.4.1.2 ***Zinc coatings***

Zinc coatings are most often applied to fasteners or other items ancillary to the pipeline itself. Zinc should be applied to steel by one of the following methods:

a) galvanizing;

b) electroplating;

c) spraying;

d) painting.

Guidance on the use of zinc coatings for steel structures and equipment in a marine environment is provided in BS 5493. The plating of threaded components should, however, conform to BS 3382-2:1961.

NOTE Zinc may not act as a sacrificial anode at temperatures above 70 °C; corrosion of steel may actually be accelerated at this temperature by contact with zinc in certain environments.

7.4.1.3 ***Nickel plating***

Electronickel plating may be used as an anti-corrosive coating. Electroless nickel plating can be used as a corrosion resistant overlay on valve components but difficulty may be experienced in obtaining a high integrity coating.

Electroplated nickel coatings should conform to BS 3382-3:1965 (for threaded components).

NOTE Unlike zinc, nickel is noble to steel, and in the event of coating damage, it is likely to accelerate corrosion of the base metal.

7.4.1.4 ***Sprayed aluminium***

Sprayed aluminium conforming to BS 2569 and BS 5493 will provide a sacrificial protection system with a finite life related to its thickness.

7.4.2 Internal cladding

7.4.2.1 ***General***

It may be desirable to separate the corrosion resistance and mechanical strength requirements of a pipeline by the use of an internal cladding of a corrosion resistant metal.

Clad components may be fabricated in a number of ways, including the following:

a) shaping and welding of clad plate;

b) fabrication of two coaxial pipes which are then bonded by forging or other hot pressing methods;

c) centrifugal casting of both alloys;

d) weld overlay cladding of carbon steel pipe and fittings.

NOTE Cladding may be considered as a supplementary means of corrosion protection for areas where corrosion inhibition is likely to be ineffective or where concentrations of corrosive agents are likely to occur e.g. in areas of high turbulence or in stagnant areas.

7.4.2.2 ***Selection***

Guidance on the resistance of material to common forms of corrosive attack is given in **7.2**.

7.4.2.3 ***Extent of cladding***

Where cladding is used, all parts of the pipeline in contact with the corrosive substance should be protected. Welds, valves and other fittings should be at least as corrosion-resistant as the main line pipe. Cladding thickness should be sufficient to ensure the following:

a) adequate corrosion resistance to withstand all predictable corrosion upset conditions over the design life;

b) a continuous corrosion resistant layer after welding.

7.4.2.4 ***Cladding methods***

Plate clad with nickel alloy should conform to ASTM A265:1984. Plate clad with stainless chromium-nickel steel should conform to ASTM A264:1990. The production route should be qualified to ensure that the mechanical properties of the parent metal and the corrosion resistance of the cladding alloy are retained after processing. Testing should include intergranular corrosion and pitting corrosion testing, using methods such as those contained in ASTM A262:1984 (for austenitic stainless steels).

Cladding by weld overlay should be qualified in accordance with ASME IX:1983.

7.4.2.5 ***Joining of clad components***

Welding of clad components should conform to qualified procedures. Welds should also be tested for intergranular corrosion and pitting corrosion resistance by the same method as is applicable to the parent cladding material. The joining of clad pipes may require the development of more complex procedures than for carbon steel pipes.

7.4.3 External cladding

7.4.3.1 ***General***

External cladding is particularly suited to the protection of risers in the splash zone.

Consideration should be given to the following in the selection of cladding:

a) corrosion resistance in the splash zone;

b) resistance to fouling;

c) resistance to mechanical damage, e.g. minor impacts;

d) weldability;

e) ease of repair.

Suitable materials for splash zone protection include the following:

1) nickel-copper alloys;

2) cupronickels;

3) certain copper-containing stainless steels.

NOTE Hydrogen may accumulate under cladding, causing failure.

No leak paths allowing water to penetrate between cladding and substrate should be permitted. The effect of a clad riser on the cathodic protection system of the pipeline and platform should be considered.

7.5 Corrosion inhibitors

7.5.1 Selection of inhibitors

If inhibitors are to be used in the control of internal corrosion, the following factors should be taken into account:

a) compatibility with pipeline materials, particularly non-metallic materials and valve internal components;

b) product and flow conditions in the pipeline;

c) inhibitor efficiency in reducing corrosion;

d) solubility and dispersibility of inhibitor;

e) temperature stability of inhibitor;

f) working life of inhibitor;

g) environmental effects, if waste is to be discharged at sea;

h) compatibility with other additives;

i) foaming and emulsifying effects (which may be detrimental to downstream separation);

j) inhibition of upstream facilities, e.g. possibility of carryover of downhole inhibitors;

k) monitoring of effectiveness;

l) method of introduction.

7.5.2 Types of inhibitor

7.5.2.1 ***Film-forming inhibitors***

A relatively high concentration of inhibitor is likely to be required initially in order to build up a protective film on the steel surface, after which smaller quantities may be required to maintain the film. Film-forming inhibitors are ineffective against erosion and in areas of high velocity and turbulence.

NOTE Stable films of inorganic salts may be used to inhibit corrosion in aqueous lines.

7.5.2.2 ***Neutralizing inhibitors***

These inhibit corrosion by altering the pH, thereby reducing corrosion by carbonic and other acids. Their compatibility with other inhibitors should be considered.

7.5.2.3 ***Biocides***

Consideration should be given to the use of biocides to control growth of bacteria and other micro-organisms. Some biocides also alter the pH and may therefore require a neutralizing inhibitor.

7.5.2.4 ***Scavengers***

Scavengers react with corrosive constituents of the process stream, such as hydrogen sulphide, oxygen and residual water.

7.5.2.5 ***Scale inhibitors***

The use of inhibitors should be considered as a means of preventing scale build up in aqueous lines. Adjustment of the pH of the fluid may be required for optimal performance.

7.5.2.6 ***Mixtures of inhibitors***

It may be necessary to introduce several inhibitors, either sequentially or as a mixture. The compatibility of the inhibitors should be considered.

7.5.3 Application of inhibitors

7.5.3.1 ***General***

At the pipeline design stage, the use of inhibitors should be considered under the following circumstances:

a) water-soluble corrosion inhibitors may be needed during commissioning and hydrotesting of pipelines;

b) during production, other inhibitors are likely to be required.

7.5.3.2 *Methods of application*

Pipelines can be inhibited by batch treatment or continuous application.

The following should be considered:

a) equipment specification;

b) procedures for inhibitor introduction;

c) disposal;

d) length of adequate inhibitor carry.

7.6 Internal corrosion monitoring

7.6.1 Selection of corrosion monitoring techniques

Consideration should be given to the following when selecting a suitable monitoring technique:

a) type of corrosion anticipated;

b) conductivity of fluid;

c) flow characteristics;

d) corrosion rate anticipated;

e) access.

In general two or more techniques should be used, since instrument readings are open to misinterpretation should localized corrosion or fouling occur.

7.6.2 Monitoring methods

Suitable monitoring techniques and applications for pipelines are shown in Table 4.

7.6.3 Positioning of probes

Corrosion probes should be fitted flush with the internal wall of the pipe where pigging may occur. The installation of additional probes in areas of high velocity flow should be considered.

NOTE Some instruments such as ultrasonic thickness gauges and certain types of hydrogen probe may be used from the exterior of the pipeline.

7.7 Cathodic protection

Defects in the external coating systems enable the pipeline steel to come in contact with its surroundings and allow electric currents to flow, resulting in pipeline corrosion, often in the form of pitting at small coating defects. A cathodic protection system should be installed to mitigate this corrosion.

Cathodic protection may be applied by the sacrificial anode or impressed current method.

The cathodic protection system should be brought into operation as soon as possible following pipeline construction and where delays are unavoidable, the use of temporary sacrificial anodes should be considered. The application of cathodic protection to a pipeline may cause adverse effects on structures close to the protected pipeline.

Table 4 — Monitoring methods

Technique	Application	Notes
Corrosion coupons	All forms of corrosion	Not suitable for SCC or SSC
Electrical resistance probes	Uniform corrosion	Not always suitable for sour service applications
Hydrogen probes	Sour corrosion HIC and SSC	Not suitable for other forms or corrosion
Linear polarization probes	Uniform corrosion	Require continuous electrolyte
Product analysis	General corrosion rates	Will not detect very localized corrosion or environment assisted cracking
Thin layer activation probes	Uniform corrosion and erosion	Double activated layers required to detect localized corrosion
Galvanic probes	Product corrosivity	Suitable to monitor oxygen ingress etc.
Ultrasonic thickness gauges	Uniform corrosion and erosion	Does not reliably detect localized corrosion
Radiography	Localized	HIC and other forms of cracking may not be detected
Inspection vehicles	General corrosion and erosion and localized pitting	HIC and other forms of cracking may not be detected

Key
HIC — Hydrogen induced cracking
SSC — Sulphide stress cracking
SCC — Stress corrosion cracking

Section 8. Weight coating, insulating and buoyancy materials

8.1 Weight coating design considerations

8.1.1 Loads on coatings

Coatings should be designed to resist installation and in service loads. The following types of loads should be considered:

a) pipe lay tensioner, roller and lay span loads;

b) pipe tow abrasive loads;

c) pipe trenching loads;

d) fishing activity impact and pull over loads (see Table 5);

e) handling and transportation loads.

Table 5 — Fishing equipment

Gear type	mass kg	Trawl speed kn
Flat rectangular door	2 000	5
V-door	2 000	5
Oval door	2 500	5
Polyvalent	2 000	5
Beam trawl	10 000	7

The most severe loading which the pipeline is liable to encounter during its lifetime should be considered.

The design should allow for the transmission of shear loads to prevent coating slip in lay tensioners.

NOTE Concrete weight coatings do not adhere well to some coatings especially epoxy powders (otherwise known as fusion bonded epoxy). Slip between the concrete and the pipe may be prevented either by using a non-smooth coating or by the addition of antislip bands.

For pipelines that will not be protected by other means it should be demonstrated either by comparison with existing experience or by testing, that the coating will not be damaged by fishing activities. The most extreme data relating to fishing equipment encountered in the UK offshore sector are shown in Table 5.

8.1.2 Integrity of coating

In order to provide a coating of acceptable quality a minimum 28 day core strength (to BS 1881) of 3.5×10^7 N/m^2 should be provided. Much higher strengths are obtainable by using application processes capable of working with very low ratios of water to cement of 0.35 and less. Where necessary, these processes should be used.

The chosen thickness of the coating should recognize the working limits of the available application processes. Thicknesses less than 45 mm should be evaluated to ensure their suitability for application and endurance under loading.

Strength tests should be carried out on cores cut from coated pipe (see BS 4019-1:1974 and BS 6089:1981). These tests should be supplemented with strength tests carried out on 100 mm cubes made from concrete taken from the batching plant (see BS 1881-116:1983).

Coating densities less than 2 240 kg/m^3 may require aggregates which reduce the strength of the coating.

Steel reinforcement should be provided to limit spalling and to control cracking (see **8.2.4**).

The anti-corrosion coating can be damaged by concrete coating application. The concrete coating application process should recognize the thickness and type of material being coated and ensure that coating penetration or unacceptable damage to the corrosion protection system does not result.

8.1.3 Water absorption

Tests should be made prior to and during production of the weight coating to ensure that water absorption does not exceed 5 % (*m*/*m*). Testing of dried cured concrete core samples should be in accordance with BS 1881.

8.2 Weight coating materials

8.2.1 Cement

Portland cement should conform to BS 12:1991, sulphate resisting cement (SRC) to BS 4027:1991 and Portland blast furnace cement to either BS 146:1991 or BS 4246:1991.

8.2.2 Sand and aggregates

Sand and aggregates should be selected to suit the application method and specified coating properties and be graded as specified in BS 882:1983. Consideration should be given to maximum particle size and the amount of fines smaller than 150 µm (see also BS 812).

Aggregates producing a coating density less than 2 240 kg/m^3 should be used with care to ensure that the application process does not damage them.

8.2.3 Water

The water used in concrete should be of potable quality (see BS 3148:1980).

8.2.4 Reinforcement

Reinforcement should be provided by steel bars embedded in the concrete either in the form of rigid preformed welded cages or as helically wrapped welded mesh. Reinforcement wire and mesh should conform to BS 4482:1985 and BS 4483:1985. Table 6 provides recommendations for the size and distribution of steel wire reinforcements.

Table 6 — Welded reinforcement

	Longitudinal reinforcement	Circumferential reinforcement	Reinforcement type
Typical bar diameter (mm)	3 to 8	5 to 12	Welded cages
Bar spacing (mm)	75 to 400	75 to 150	
Percentage of coating sectional area	0.1 to 0.2	0.45 to 1.0	
Typical bar diameter (mm)	2 to 4	2 to 4	Wire mesh
Bar spacing (mm)	50 to 300	65 to 100	
Percentage of coating sectional area	0.08 min.	0.4 min.	
NOTE Alternative reinforcement materials such as glass fibre may be acceptable if they provide equivalent performance.			

Wrapped-in welded wire mesh should be galvanized as specified in BS 729:1971 or BS 443:1982.

Concrete cover should not be less than 19 mm and the clearance between reinforcement and anti-corrosion coating should not be less than 15 mm.

Double layer reinforcement should be considered for coating thicknesses greater than 80 mm.

The reinforcement should be electrically isolated from the pipe and rigidly held concentric with the pipe. Cage reinforcement should be positioned by the use of electrically insulating spacers.

8.3 Weight coating application

8.3.1 Temperature

Coating application should not be allowed if any of the following conditions are present:

a) concrete mix temperature is less than 3 °C, or pipe temperature is less than 3 °C;

b) ice is on any of the surfaces or in the constituents;

NOTE Steam heating of aggregates is permissible.

c) temperature of pipe, its coating, the reinforcement or the concrete mix exceeds 35 °C.

8.3.2 Reinforcement

Steel reinforcement cages should be supported on electrically insulating spacers prior to impingement coating.

When application by wrapping is made the reinforcement should be tensioned and wrapped with the concrete and supportive outer membrane. Successive wraps of reinforcement should overlap.

8.3.3 Curing

Unless steam or water spray immersion is used, curing membranes should be applied with the coating or immediately after coating. The curing membrane should be a plastics wrap conforming to ASTM C171:1986 or a spray applied coating of equivalent performance.

The ambient temperature for pipe storage should not be allowed to fall below 2 °C until the concrete has a minimum strength of 10^7 N/m^2. It should not be allowed to rise to an injurious level for the corrosion protection coating.

8.3.4 Anodes

Electrical and mechanical attachment of the anode to the pipe joint should be made and tested prior to concrete coating.

The anode, its mechanical attachment and electrical attachment should be contained within the profile of the concrete coating. Any differences in diameter should avoid step changes. Any gap between the concrete coating and the sides of the anode should be infilled with mastic or similar. It is essential that any steel reinforcement in the weight coating is not in contact with the anodes. Anodes should be isolated from concrete containing metallic ore aggregates.

8.3.5 Tolerances

Tolerances on the submerged weight of each pipe are of primary importance. The specified tolerance should recognize the possible variations resulting from pipe mill tolerance, corrosion protection coating thickness tolerances, and water absorption.

Submerged pipe weights should be obtained from the calculated displacement of seawater and the measured in-air weight of each pipe.

The submerged pipe weight tolerance should typically be as follows:

a) allowable range for any pipe: – 10 % + 20 %;

b) range per 25 pipes produced: – 2 % + 6 % on a rolling 25 pipe average;

c) range for the daily coating plant production – 0 % + 4 % on a day’s production.

8.4 Storage and handling

After coating, the pipes should be stored with a minimum amount of handling until the coating is set and fully hardened. Coated and uncoated pipe should at all times be stored out of contact with the ground. Coated pipe, however, should not be placed on skids or racks until the coating has hardened sufficiently to prevent flattening.

Pipes should only be stacked to a height that does not cause flattening of the coating. Concrete coated pipes should not be stacked until the coating has achieved a minimum compressive strength of 1.4×10^7 N/m^2.

8.5 Damage

8.5.1 Assessment of defects (at coating yard)

Concrete coating should be inspected. Localized repairs are permissible if less than 20 % of the coated area is damaged otherwise total recoating should be carried out. Hairline circumferential cracking is not considered to be a coating defect.

8.5.2 Repair techniques

Repairs to the coating should be made with materials of equivalent strength and weight to that of the coating. Either hand trowelling or guniting are acceptable.

8.6 Insulating materials

Insulating materials are used to maintain operating temperatures in pipelines and their properties should be taken into account when calculating the submerged weight.

The following materials are used:

a) polychloroprene;

b) polychloroethylene;

c) gels;

d) closed cell polyvinylchloride;

e) glass bubble filled resins (synthetic foam);

f) closed cell polyethylene foam;

g) closed cell polyurethane foam;

h) backfill including rock or sand.

Pipeline bundles contained in carrier pipes can be insulated with gels or other insulating materials.

All materials should have an established capability for the intended duty including the ability to withstand the hydrostatic load for the design life.

A suitable outer coating or sheathing should be applied to protect the insulation coating particularly where concrete coating is to be applied.

Section 9. Jointing

9.1 Jointing

Jointing and welding procedures and techniques should be chosen to maintain the mechanical and corrosion properties inherent in the parent materials.

The choice of a particular jointing technique should be made on the basis of the ability to produce an acceptable joint and inspect it, in the environment in which the joint is made.

9.2 Welding

9.2.1 Field welding

The requirements of more than one standard should not be applied to a single welded joint except where specific cross-referencing between standards occurs. Field welding of carbon and low alloy steels should conform to BS 4515:1984.

Consideration should be given to the use of processes and consumables which limit hydrogen content of the weld metal to prevent cold cracking.

The welding of high alloys and clad pipes should comply with qualified procedures generally in accordance with BS 4515:1984. Inspection of the high alloy section should be undertaken before continuing the weld. The welding process should not reduce the integrity or thickness of the corrosion resistant material below minimum acceptable limits. These welds should be tested in accordance with an appropriate procedure.

Care should be taken during welding to avoid damage to adjacent coatings.

9.2.2 Fabrication welding

Prefabricated pipework may be welded in accordance with ANSI B 31.3:1987, BS 2633:1987, BS 4677:1984, BS 4870, BS 4871, BS 4515:1984 or API 1104:1988 as appropriate.

9.2.3 Fracture toughness

For further guidance on fracture toughness of welds, refer to BS 4515:1984.

9.3 Special welding methods

9.3.1 General

Any welding technique not covered by relevant national or international standards should only be applied subject to a comprehensive development and qualification programme before use. The development and qualification programme should include the following:

a) pipe size limitations;

b) limits of acceptable process variables;

c) acceptable defects;

d) non-destructive testing techniques;

e) joint configuration tolerances;

f) line-up methods;

g) post-weld heat treatment;

h) post-weld joint clean-up (e.g. flash removal);

i) pipe position.

9.3.2 Friction welding

Friction welding should conform to BS 6223:1990. Acceptance criteria should be developed from an engineering critical assessment in accordance with PD 6493:1991.

9.3.3 Electron beam welding

Electron beam welding should be conducted in accordance with AWS F2.1:1978. Acceptance criteria should be developed from an engineering critical assessment in accordance with PD 6493:1991.

9.3.4 Flash butt welding

Flash butt welding should conform to BS 4204:1989. Defect acceptance should conform to BS 4204:1989 and BS 4515:1984.

9.3.5 Wet welding

Wet welding should not be used on pressure-containing items.

Wet welding for other applications should be in accordance with AWS D3.6:1989.

9.3.6 Thermit welding or brazing

Thermit welding or brazing should only be used for attaching anode bonding leads. Consideration should be given to minimizing alloy penetration from the bonding lead into the parent pipe material. Acceptance criteria should be based on the establishment of electrical continuity and mechanical strength.

9.4 Weld inspection

Selection of the appropriate weld inspection technique, acceptance criteria and the frequency of inspection should conform to the relevant welding standard.

Typical inspection techniques and standards are given in Table 7.

Table 7 — Inspection techniques and typical standards

Inspection technique	Procedure standard
Visual inspection	BS 5289:1976
Magnetic particle inspection	BS 6072:1981
Dye penetrant	BS 6443:1984
Radiographic inspection	BS 2600 BS 2910:1986
Ultrasonic inspection	BS 3923 BS 3889

9.5 Hyperbaric (dry habitat) welding

Hyperbaric welding of subsea pipelines may be carried out for subsea completions, pipeline/riser tie-ins and in emergency repair situations.

Hyperbaric welding should be carried out in accordance with appendix J of BS 4515:1984 up to the 200 m depth limit imposed within the scope of that standard. Applications at greater depths should use BS 4515 for guidance, with further consideration being given to the effect of hydrostatic pressure.

Special welding methods (see **9.3**) may be applied to hyperbaric welding but should be subject to a development and qualification programme.

Hyperbaric welding of high alloy materials should conform to BS 4677:1984 and BS 4515:1984.

9.6 Non-welded joints

9.6.1 General

When selecting a non-welded jointing method consideration should be given to the following:

a) pipeline operating conditions;

b) installation methods, stresses and loads;

c) corrosion resistance;

d) joint mechanical properties;

e) joint reliability;

f) joint maintenance requirements;

g) joint inspection and testing techniques during and after construction.

The non-welded joint should provide structural integrity and corrosion resistance equal to or better than the design requirements for the parent pipe.

A connection method should have proven reliability under the proposed operating conditions. Proving trials should be performed where this is not the case.

The design of equipment and fittings for mechanical connections is considered in section **6**.

9.6.2 Flanged joints

For guidance on flanged joints, see **6.2**.

9.6.3 Screwed joints

Consideration should be given to the following:

a) make up torque and its measurement;

b) jointing compounds;

c) potential corrosion at joints and crevices;

d) product composition.

9.7 Other relevant British Standards

BS 639:1986, *Specification for covered carbon and carbon manganese steel electrodes for manual metal-arc welding.*

BS 2493:1985, *Specification for low alloy steel electrodes for manual metal-arc welding.*

BS 2901, *Filler rods and wires for gas-shielded arc welding.*

BS 2901-1:1983, *Ferritic steels.*

BS 2901-2:1990, *Specification for stainless steels.*

BS 2901-5:1990, *Specification for nickel and nickel alloys.*

BS 2926:1984, *Specification for chromium and chromium-nickel steel electrodes for manual metal-arc welding.*

BS 4165:1984, *Specification for electrode wires and fluxes for the submerged arc welding of carbon steel and medium-tensile steel.*

BS 5135:1984, *Specification for arc welding of carbon and carbon manganese steels.*

BS 5465:1987, *Specification for electrodes and fluxes for the submerged arc welding of austenitic stainless steels.*

BS 5500:1991, *Specification for unfired fusion welded pressure vessels.*

PD 6493:1991, *Guidance on methods for assessing the acceptability of flaws in fusion welded structures.*

BS EN 10045, *Charpy impact test on metallic materials.*

BS EN 10045-1:1990, *Test methods (V- and U- notches).*

Section 10. Installation

10.1 General

10.1.1 Safety

High standards of safety should be maintained at all times. Safety training should be given to all employees engaged in supervision and construction of pipelines. Safety procedures and equipment should be provided for normal installation and contingency conditions.

10.1.2 Construction supervision

It is essential that competent and experienced staff supervise and inspect all pipeline construction activities.

10.2 Marine operations

10.2.1 Vessels

Prior to mobilization to site of construction vessels such as lay barges, trench barges and diving support vessels, it is recommended that an inspection or survey is performed to confirm principal equipment is suitable for the intended work.

10.2.2 Anchors and station keeping

10.2.2.1 ***General***

The station keeping system should have adequate redundancy to ensure that other vessels or installations are not endangered by its partial failure.

10.2.2.2 ***Anchor patterns***

Any construction vessel using anchors to maintain position should do so in accordance with a predetermined anchor pattern. The anchor pattern should be shown on a chart, of appropriate scale, containing the following information:

a) position of each anchor and cable touch down point;

b) location of existing pipelines and installations;

c) vertical clearance between anchor cables and pipelines;

d) proposed pipeline route and lay corridor;

e) temporary works present during the construction period;

f) anchor patterns of other vessels in the vicinity;

g) vessel position for running each anchor;

h) working position(s) of vessel once anchor running is complete;

i) prohibited anchoring zones.

Care should be taken in correlating different survey data.

Vessels should have a procedure for leaving the work location in an emergency or when anchors cannot be recovered.

10.2.2.3 ***Anchor and cable clearances***

The clearance to be imposed between an anchor, its cable, and a fixed structure, subsea installation or pipeline should take the following into consideration:

a) duration at location;

b) prevailing weather direction and seasonal weather;

c) other work locations and emergency stand off location;

d) type of soil conditions;

e) anchor system and loading;

f) planned movement of vessel both towards and away from a structure;

g) tidal and current variations;

h) additional measures implemented to prevent damage.

10.2.2.4 ***Anchor handling***

All anchors transported over subsea installations or pipelines should be decked onto the anchor handling vessel and be secure.

Construction vessel anchor winches should be equipped with a cable footage and load indicator. These should be calibrated during mobilization.

Attention should be paid to anchor running in shallow water when anchor cables may not follow the straight line route between anchored vessel and anchor.

10.3 Vessel positioning

10.3.1 Positioning systems

Horizontal surface positioning should form the basis for locating prime construction vessels, pipeline position and points of reference for local positioning systems.

The system chosen should be able to give a continuous position compatible with the required positioning tolerances imposed by the choice of the pipeline route and anchor locations.

The system should feature a 100 % redundancy or standby to allow for breakdown. It should provide the following information:

a) position relative to the chosen grid reference system;

b) geographical position;

c) visual display and record of planned and actual pipeline route and actual track;

d) visual display and record of other positionally fixed structures;

e) offsets from antenna position.

NOTE During installation within congested areas or during start up and laydown, a local positioning system of greater accuracy may be required, such as acoustic transponder systems. Remotely operated vehicles (ROVs) may be used to monitor the touchdown point.

10.3.2 Dynamic positioning

Dynamic positioning systems on vessels should conform to Department of Energy Guidelines 1983 [27].

10.3.3 Calibration

Prior to performing construction activities the positioning system should be calibrated to ensure all functions are operating within the prescribed limits of accuracy.

10.4 Pipeline installation

10.4.1 General

10.4.1.1 ***Procedures***

Procedures should be developed to demonstrate that construction can be performed in a safe and efficient manner according to the engineering specifications and relevant codes and regulations (e.g. HSE regulations).

10.4.1.2 ***Survey***

Prior to installation a survey should be performed along the proposed pipeline route corridor (see **4.1.6**).

10.4.1.3 ***Material transportation and storage***

Care should be taken to prevent damage to pipes, fittings and coatings during handling. Slings or equipment used for handling pipes should be designed to prevent pipe or coating damage.

Storage of pipes should be in pipe racks with protection to minimize damage to pipes and coatings. Maximum stacking heights should be established which do not impose excessive loads on the pipe or its coatings.

All material should be manifested and pipe tracking records maintained.

10.4.1.4 ***Welded fabrication***

Prior to welding, each pipe should be checked for mechanical damage both to the pipe steel and to any pipe coating. All pipe alignment and welding should be as recommended in **9.2**. As each joint is welded the pipe number should be recorded together with the length of the pipe. The laying sequence number should be painted on either side of the pipe in contrasting paint.

10.4.2 Laybarge method

10.4.2.1 ***Pipeline fabrication***

Dimensions and tolerances should be in accordance with **5.1.2**. Care should be taken to avoid disruption at the laybarge work stations through the use of successive short or long lengths of pipe.

10.4.2.2 ***Field joint coating***

This should be as recommended in **7.3.6**.

10.4.2.3 ***Pipeline installation configuration***

The pipe should be maintained under controlled tension to ensure it is lowered onto the seabed within the stress limits given in **4.2.5** or allowable strain given in **4.2.7**.

10.4.2.4 ***Pipeline support***

The pipeline should be supported along the length of the barge on rollers or tracks that allow the pipe to move axially. The rollers should be faced with a material that will not damage the pipe coating, field joint coatings or anodes.

The height and spacing of the rollers should be adjusted to ensure a smooth transition from the barge to the stinger and be spaced to maintain the loads in the pipeline within the limits given in **4.2.5** and **4.2.7**. Pipeline fitting should be prevented from hooking behind rollers.

10.4.2.5 ***Stinger***

The pipeline supports on the stinger should be similar to those on the laybarge and should be equipped with load cells. Should the stinger be of the buoyant type, the last roller mounted on the barge should also be equipped with a load cell.

A video camera should be maintained at the end of the stinger to view the pipeline at the last roller.

10.4.2.6 ***Buckle detection***

Consideration should be given to the use of a buckle detector during laying such that reductions in diameter of the pipe of 5 % or greater are detected.

The buckle detector should always remain behind the touch down point of the pipe on the seabed.

The effects of pipeline tees or fittings on buckle detectors should be considered.

10.4.2.7 ***Contingency procedures***

Contingency procedures should be available to ensure that repairs may be performed should any damage occur during pipelaying operations. Possible types of damage include the following:

a) dry buckle;

b) wet buckle;

c) loss of weight coating;

d) loss of corrosion coating;

e) abandonment and recovery.

The pipelay start-up head should be equipped with the necessary valves and pre-installed pigs to enable the pipeline to be dewatered in the case of a wet buckle.

10.4.2.8 ***Instrumentation and recording***

Instrumentation should be provided to monitor and record the following:

a) pipe tension at each tensioner;

b) total tension;

c) tension and footage of constant tension winch during abandonment and recovery;

d) barge and stinger roller loadings;

e) pipeline position with respect to stinger tip;

f) stinger configuration and tip depth, if buoyant;

g) anchor cable loads.

10.4.3 Towing methods

10.4.3.1 ***General types of tow***

General types of tow include the following:

a) bottom tow (including off-bottom tows), in which the pipeline remains in contact with or in close proximity to the seabed;

b) mid-depth tow, in which the pipeline is towed well clear of the seabed;

c) surface or near surface tow, in which the pipeline is supported by surface buoys.

NOTE Surface tow methods are only used for short lengths of pipeline or where wave and current actions are minimal.

Notification should be given to operators of pipelines and cables which will be crossed during a pipeline tow operation, the coastguard, fishermen and other users of the sea.

A monitoring vessel should be used to prevent interference with the pipeline by third party vessels.

A precise material and weight control system should be implemented during fabrication.

The individual pipe strings should be hydrostatically tested prior to tow out in addition to other hydrostatic testing requirements (see section **11**). Consideration should also be given to air testing the sleeve pipe to confirm its integrity.

10.4.3.2 ***Procedures***

Procedures should be prepared for the following:

a) towing route survey;

b) pipestring make up onshore;

c) ballast control;

d) pipestring configuration analysis;

e) weather restrictions and contingency for adverse weather conditions;

f) pipestring positioning during tow and for placement;

g) pipeline/cable crossing procedures;

h) deballasting;

i) tie-in;

j) implementation of contingency plans;

k) monitoring the towing tensions.

10.4.3.3 ***Bottom tow***

Care should be taken to ensure that the pipeline route avoids rock outcrops or other obstacles which may damage the pipeline, coating or anodes during installation. The ability of the pipeline coating to resist abrasion should be investigated.

10.4.3.4 ***Mid-depth tow***

The towing speed and tensions should be controlled and monitored to maintain the required tow depth.

10.4.4 Reeling

10.4.4.1 ***Procedures***

Procedures should be prepared for the following:

a) loading the reel;

b) start-up;

c) lay-down;

d) control of tension;

e) abandonment and recovery;

f) installing/joining additional pipestrings;

g) implementiation of contingency plans.

10.4.4.2 ***Laying***

Attention should be given to the effect on material characteristics, coatings and circumferential welds. The possibility of buckling and excessive ovality of the pipe should be examined. Flexible pipelines should be laid in accordance with the manufacturers recommendations (see **4.3**).

Steel pipe should be unreeled and straightened prior to or during passage through a tensioner. The reel should not be used to control the tension of the pipeline during laying, unless it can be shown that there will be no detrimental effects.

10.4.4.3 ***Loading the reel***

Fabrication of the pipestrings should be performed as recommended in **10.4.1.4**. Adequate support should be given to the pipe during reeling and measures taken to prevent damage to protective coatings.

It is recommended that a sample of pipe be passed through the pipe straightener to test the setting during mobilization of the vessel and to ensure that ovality and straightness are maintained within specified limits.

10.4.4.4 ***Anodes***

It is usually necessary to install anodes after the pipe has passed through the straightener and tensioner. The anodes and their attachment should be designed to pass through trenching equipment if post lay trenching is to be performed.

10.4.5 Other installation techniques

10.4.5.1 ***Strapped bundle***

The strapping arrangement should ensure that the smaller line cannot slip and that it does not foul any part of the installation equipment.

Precautions are required when trenching these pipelines to minimize the possibility of damage to the smaller pipe.

10.4.5.2 ***Others***

Other installation methods (such as J-lay) may be suitable for use in particular instances. Prior to using any novel pipeline installation method, a study of the technique should be performed to analyse the loads imparted on the pipe during installation.

10.5 Span rectification

10.5.1 General

Span rectification should be undertaken when the state of the span is unacceptable in terms of the criteria given in **4.6** or where there is a requirement to avoid spanning because of potential damage from fishing activities.

In specific situations, the presence of a pipeline span, although deemed acceptable structurally, may have potential for interference with fishing vessels and their gear as well as other legitimate users of the sea. Where the possibility of interaction is identified and the risk created to fishing vessels or other users of the sea is significant then action should be taken to rectify the span.

10.5.2 Seabed preparation

Pre-lay seabed preparation should be undertaken if the predicted span exceeds the allowable span length for the as-laid, empty, construction load condition (see **4.6**). The preparation includes the following:

a) infilling of seabed depressions;

b) removal of high-spots.

Consideration should be given to pipelay tolerances in determining the width of the prepared corridor.

10.5.3 Post-lay span rectification

Span rectification should be carried out where the pipeline span exceeds the relevant allowable span length(s) (see **4.6**).

Consideration should be given to the potential for span generation and extension resulting from scour or differential seabed settlement.

10.6 Pipeline crossings

10.6.1 General

Crossing locations, anchor patterns and handling should be pre-determined and agreed by all parties prior to installation (see **4.7**).

10.6.2 Pre-set supports

The position of the existing pipeline should be accurately established prior to setting the supports. Vessel anchoring should be conducted as recommended in **10.2** for crossing other subsea installations. Due to the close tolerances required, the crossing should be monitored by ROV to confirm proper placement of the pipeline. Horizontal surface positioning systems alone will not normally be sufficiently accurate to position the pipeline over the supports.

A continuous support and a smooth profile over the pipeline should be achieved to reduce risk of damage to the pipeline and fishing vessels from impact.

10.7 Pipeline tie-ins

10.7.1 Stresses

Installation stress induced in short discrete sections of line pipe such as expansion offsets and post-installed risers should be controlled to below the limits defined in **4.5**.

Prior to completing the tie-ins, consideration should be given to establishing that the tie-in ends are positioned within the tolerances as determined in the design stress analysis. If the as-built positions and dimensions of the tie-in are outside the allowable analysis limits, a new analysis should be carried out to determine the acceptability of the tie-in configuration.

10.7.2 Jointing

10.7.2.1 ***Hyperbaric (dry habitat) welding***

Following hyperbaric welding (see **9.5**) the exposed joint should be protected against corrosion (see section **7**).

10.7.2.2 ***Mechanical jointing systems***

Mechanical jointing systems should be protected by a shroud or cable deflector to prevent cables snagging.

When flanges are used for tie-ins, consideration should be given to designing one of the pair of flanges, usually the installed spool side, to be a swivel or lap type flange. This facilitates the alignment of the bolt holes of the two mating flange faces.

Hydraulic bolt tension equipment should be considered for all flanged connections.

Many proprietary connector systems allow a degree of axial misalignment which can greatly simplify the tie-in operation. Full account should be taken of the manufacturer's specifications when assessing their suitability.

10.7.3 J-tubes

The J-tube will normally be installed during jacket fabrication. Before installation of the pipeline a survey should be made to confirm the following:

a) that the J-tube bellmouth is clear of debris or obstruction;

b) that the height of the bellmouth above the seabed is within design limits;

c) that the bellmouth, J-tube, and the J-tube clamps are undamaged.

Pipeline installation will usually be performed by a pull-in winch located on the platform. The cable tension should be monitored by calibrated load cells. Entry of the pipeline into the J-tube bellmouth should be monitored by an ROV, and if the pull-in is taking place directly from a pipelay vessel, the touch down point of the pipeline on the seabed should also be monitored.

Corrosion inhibition and sealing of the annulus of the J-tube should be performed as soon as possible after the pull-in is complete.

10.8 Landfall (see also BS 8010-2.8:1992)

10.8.1 Site consideration

10.8.1.1 ***General***

The following aspects should also be considered for any construction scheme:

a) access to site;

b) onshore plant and equipment;

c) site accommodation and services;

d) onshore construction procedures;

e) offshore plant and equipment;

f) temporary works;

g) permanent works;

h) discharge of chemicals;

i) use of explosives;

j) reinstatement;

k) trenching and protection requirements;

l) proximity to other services;

m) possible breaching of sea defence works;

n) impact on environmentally sensitive areas.

10.8.1.2 ***Pipeline location and marking***

The location of any pipelines, cables, or outfalls in the area of the landfall should be determined and clearly marked.

10.8.2 Bottom pull

Where it is necessary to reduce pull loads, buoyancy tanks may be attached to the pipeline, if buoyancy is applied, its effect on the stability of the pipe should be investigated. When a cable is used to pull the pipe, care should be taken to prevent twisting.

10.8.3 Directional drilling

Directional drilling is a suitable technique where environmental and practical considerations restrict other methods and geophysical and geotechnical surveys show that it is feasible.

Consideration should be given to the following:

a) containment and disposal of drilling fluid;

b) selection of a corrosion protection system with high resistance to abrasion and low surface friction;

c) the stability of the pipeline before it is pulled into the directionally drilled hole.

10.8.4 Protection methods

The following protection methods should be considered:

a) trenching and backfilling;

b) concrete culvert;

c) shaft and tunnel.

Consideration should be given to requirements for inspection and maintenance if either method b) or c) is adopted.

10.9 Pipeline protection (see 4.12.2)

10.9.1 Trenching

10.9.1.1 ***General***

The trenching depth and profile should be regulated within the prescribed limits to ensure the pipeline is not over stressed during trenching or operation. Loads imposed on the pipeline during trenching should be monitored. Consideration should be given to the extra loads imposed if the pipeline is flooded. Periodic monitoring for boulders and debris should be carried out.

10.9.1.2 ***Jetting***

Jetting is suited to weak clays and non-cohesive soils. Care should be taken to maintain an even profile and to avoid damage to the coating when using jet sleds.

10.9.1.3 ***Ploughing***

The plough should be selected and operated to limit the stresses induced in the span behind it. Where the plough is powered by a subsea tractor consideration should be given to the seabed profile and the presence of boulders.

10.9.1.4 ***Mechanical cutting***

Mechanical cutters are suited to cohesive soils and rock. They should employ pipe tracking systems enabling them to trench the pipeline without physical contact with it.

10.9.1.5 ***Dredging***

Dredging is used in shallow water prior to pipeline installation. Care should be taken to control the dredged profile to reduce the potential for pipeline spanning.

10.9.1.6 ***Instrumentation***

Trenching equipment should be provided with instrumentation to monitor the following:

a) pitch, roll, heading, depth, and speed of machine;

b) trench profile;

c) tractive force;

d) load on rollers.

10.9.1.7 ***Trenching flexibles***

The possibility of kinking of a flexible pipeline in front of a trenching machine should be considered.

The effect of longitudinal strain when under pressure should be taken into account, to prevent the pipeline from becoming exposed at intervals.

10.9.2 Gravel and stone placing

Selected material should be placed in a controlled manner to achieve a smooth profile and to avoid damage to the pipeline and its coatings (see **4.12.2.6**). The Regulatory Authority should be consulted before any material is placed.

10.9.3 Bags and mattresses (see **4.12.2.7**)

The Regulatory Authority should be consulted before bags or mattresses are placed.

10.10 Flooding and gauging

10.10.1 General

Flooding and gauging of the pipeline should be performed after pipeline installation is completed. Prior to flooding, any free spans greater than that allowable for the flooded condition should be rectified.

10.10.2 Flooding

Flooding should be carried out as recommended in **11.5.2**.

10.10.3 Gauging

Gauging to confirm the bore of the pipe should be performed with a pig equipped with a gauging plate or with a caliper pig. Prior to running a gauging pig the line should be cleaned.

The pigs should be constructed of a material that will not harm the inside of the pipeline. The gauge plate diameter should be not less than 95 % of the minimum internal diameter of the pipeline or 25 mm less than the minimum internal diameter whichever is the larger.

10.11 As-built survey

10.11.1 General

The as-built surveys should provide an accurate record of the position and state of the pipeline and associated permanent works.

10.11.2 As-built records

Survey records should include video tapes and acoustic records of the pipeline, together with drawings showing the pipeline with at least the following marked:

a) kilometre posts;

b) pipeline markers;

c) pipe numbers and weld numbers;

d) free spans and their dimensions;

e) trench profile and depth of cover;

f) bathymetry;

g) scour;

h) damage and repairs;

i) associated works;

j) debris;

k) anodes;

l) riser clamps and pipe supports;

m) pig traps;

n) landfall details (see BS 8010-2.8:1992);

o) valves and other fittings;

p) pipeline position (eastings and northings).

Section 11. Pressure testing

11.1 General

It is essential that pipelines are pressure tested hydrostatically after all construction work has been completed, to prove their strength and leaktightness prior to commissioning.

NOTE Pneumatic testing is not acceptable for a strength test.

The pressure test should be in accordance with a written procedure.

All testing should be carried out under the supervision of a suitably experienced and competent engineer. It may be necessary to give notice to the Regulatory Authority of the intention to carry out the pressure test.

11.2 Safety

11.2.1 Precautions during a test

The following safety precautions should be adopted during pressure testing.

a) Warning notices should be erected.

b) Boundaries should be marked prohibiting unauthorized persons from approaching the pipeline test area.

11.2.2 Temporary pig traps

Care should be taken in the operation of temporary pig launchers and receivers during pressure testing. They should not be opened unless the pressure in the launcher, receiver and pipeline is equal to the ambient pressure.

Temporary pig traps should only be subject to the full test pressure if they have been designed to at least the same design requirements as the pipeline.

11.3 Equipment

11.3.1 General

Instruments and test equipment used for measurement of pressure, volume and temperature should be certified for accuracy, repeatability and sensitivity. Gauges and recorders should be checked immediately prior to each test. Dead weight testers should be certified within the 12 months preceding the test or more often if heavy use requires it. Dead weight testers should not be used in unstable situations. All test equipment should be located in a safe position outside the boundary area (see **11.2.1**).

11.3.2 Measurement of pressure

Hydrostatic test pressure should be measured by a dead weight tester having an accuracy better than ± 0.1 bar and a sensitivity of 0.05 bar. Pressure gauges should be selected with ranges which show between 50 % and 90 % of full scale deflection at the test pressure.

11.3.3 Measurement of volume

The volume of liquid added or subtracted during a hydrostatic test should be measured by equipment having an accuracy better than ± 1.0 % and a sensitivity of 0.1 % of the calculated volume of liquid to be added after line filling has been completed to produce the test pressure. Where pump strokes are used to determine the added volume an automatic stroke counter should be used.

11.3.4 Measurement of temperature

Temperature measuring equipment should have an accuracy of ± 1 °C and a sensitivity of 0.1°C.

11.3.5 Recording equipment

Pressure and temperature recording equipment should be used to provide a graphical record of the pressure test and the variation of temperature for the duration of the test.

11.4 Test pressure

The minimum hydrostatic test pressure which is required to qualify a pipeline for a MAOP equal to the internal design pressure is the lower of the following:

a) 150 % of the internal design pressure; or

b) the pressure that will result in a hoop stress (based on specified minimum wall thickness) equal to 90 % of the specified minimum yield stress.

The test pressure should be referenced to the Lowest Astronomical Tide (LAT) and due allowance made for the elevation of the pressure measuring point and parts of the system above LAT.

11.5 Test procedure

11.5.1 Water quality

Water for testing and any subsequent flushing should be clean and free from any suspended or dissolved substance which could be harmful to the pipe material or internal coating or which could form deposits within the pipeline. Consideration should be given to the use of a corrosion inhibitor, an oxygen scavenger, a biocide and a dye.

11.5.2 Line filling

Consideration should be given to the removal of internal construction debris from the pipeline prior to filling.

Unless pipeline valves have a provision for pressure equalization across the valve seats, consideration should be given to prefilling the valve body cavities with an inert liquid. All valves should be left fully open during line filling and may be partially closed prior to pressure testing.

To minimize air inclusion during line filling, the pipeline should be filled with filtered water behind at least one pig. The use of pig location device to track or locate the pig and hence the interface position is recommended. Pumps should be selected to achieve an adequate fill rate.

11.5.3 Air content

The measurement of air content should be carried out by constructing a plot of pressure against volume during the initial stage of pressurization until a definite linear relationship is apparent. By extrapolating this linear curve back to the volume axis, the air volume should be assessed, and compared with the total volume of the test section.

It is recommended that the air content should not exceed 0.2 % of the calculated capacity of the pipeline section under test. However the hydrotest may be allowed to proceed with a higher air content providing that allowance is made for the additional residual air in the evaluation, the test duration is extended accordingly and additional safety measures are taken. See Figure 4.

11.5.4 Thermal stabilization

Time should be allowed after filling for the temperature of the water in the pipeline to stabilize with that of the pipeline environment.

11.5.5 Pressurization

The pressure in the test section should be raised at a controlled rate. The volume of water added, the corresponding pressure rise and the time should be logged during this operation, and the air content calculated according to **11.5.3**. A period should be allowed for pressure stabilization during which residual air will continue to go into solution and time-dependent straining of the pipe may take place. Test pressure should then be held for a period of not less than 24 h. The volume of any water added or subtracted to maintain test pressure should be noted.

11.5.6 Pressure and temperature monitoring

A continuous record of the pipeline pressure and temperature should be made throughout the pressurizing, stabilizing and hold periods. The pressure and temperature should also be logged simultaneously at least every 30 min.

11.6 Test acceptance criteria

The pressure test should be considered satisfactory if the pipeline is free from leaks and all pressure changes that were observed during the hold period can be accounted for.

11.7 Test records

All certificates and records produced in connection with pressure testing a pipeline should be retained by the operator for the lifetime of the system. The documentation should include the following:

a) pressure recorder charts;

b) log of temperature and pressure taken every 30 min;

c) calibration certificates of test equipment;

d) calculation for air content;

e) calculation of pressure/temperature relationship and justification for acceptance.

11.8 Pre-testing of fabricated components

11.8.1 Fabricated components

Pre-fabricated pipe sections (such as risers and tie-in spools) and fabricated components (such as pig traps, valves, manifolds and slug catchers) should be pre-tested before installation in the pipeline system. The test pressure should be calculated as described in **11.4**. The test duration should be not less than 6 h. Where assemblies will be not subject subsequently to the full pipeline hydrotest, the test duration should not be less than 24 h.

11.8.2 Bundles

Onshore-fabricated pipelines and bundles should be pre-tested (see **11.8.1**) before installation.

11.8.3 Reeled pipe

Onshore-fabricated pipe strings should be pre-tested (see **11.8.1**) prior to loading onto the reel of a reel ship.

11.9 Integrity leak testing

Where the component parts of the installed pipeline have been hydrostatically strength tested and assembled using mechanical connections, e.g. flanges, forged connectors or such a connection has been disturbed following the strength test and has subsequently been reassembled, then the assembled system should be leak tested to prove its integrity.

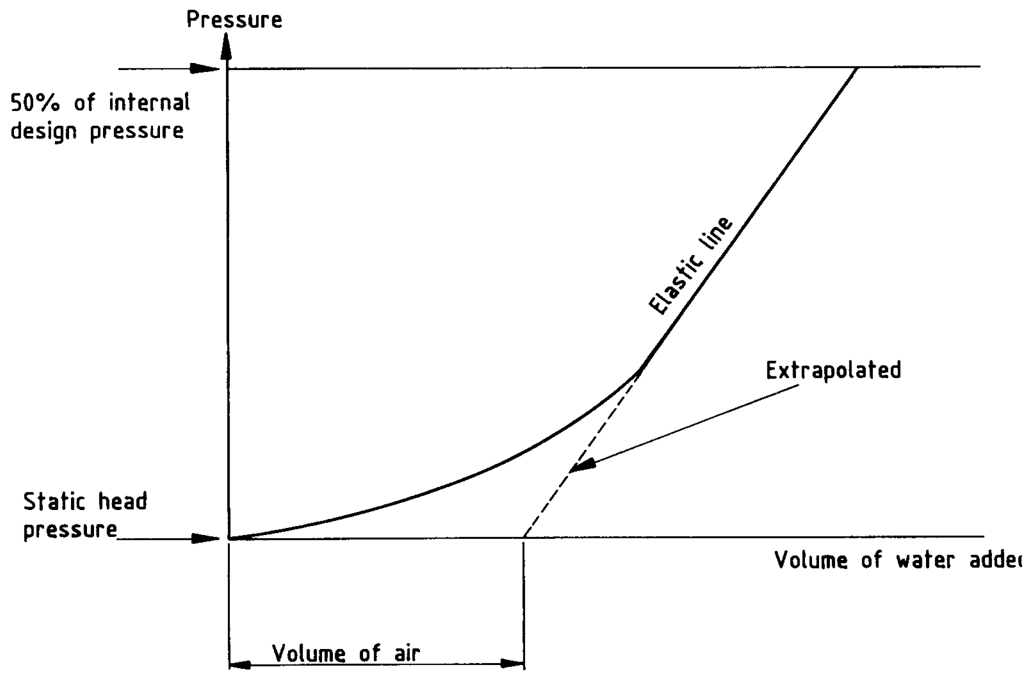

Figure 4 — Measurement of air content

The test pressure should be not less than 1.1 times the MAOP of the pipeline and this pressure should be held for a period sufficient to confirm the integrity of all joints under test. The test medium should preferably be water but nitrogen with a helium trace may be used where this is not practicable. Product should only be used in extreme circumstances when no alternative methods are available and adequate controls for the safety of personnel in the vicinity of the pipeline can be affected. Consideration should be given to the use of fluorescent tracer dye in the test water to facilitate the detection of leaks subsea.

Relief valves may need to be isolated or locked to achieve the test pressure.

11.10 Tie-in welds

Where tie-in welds will not be subject to subsequent strength testing they should be subject to 100 % radiographic inspection, supplemented by 100 % ultrasonic examination.

11.11 Flexible pipelines

11.11.1 General

The response of flexible pipelines to hydrostatic testing differs from the response of steel pipelines. Flexible pipelines are liable to creep, and therefore stabilization should include a period for settlement of the composite structure. A reduction in the internal pressure is likely, but the rate of decay will decrease with time. The pipeline should be pressurized to slightly over test pressure to allow for stabilization. Alternatively it may be brought back to test pressure after a period of stabilization. If the test is commenced whilst stabilization is still occurring, the maximum drop in pressure during the test should not exceed 1.0 % after allowance for temperature variations.

11.11.2 Test pressure and duration

The minimum test pressure should be equal to 150 % of the design pressure. The test pressure should be held for 24 h. Where the pipeline system includes both flexible and steel pipe, it may be necessary to modify the test pressure to comply with the yield stress condition in the steel pipe (see **11.4**). In such cases the flexible sections should be pre-tested before installation and the tie-in connections should be examined for possible leaks during the final test.

Section 12. Precommissioning and commissioning

12.1 General

The following activities should be considered before the introduction of the product:

a) dewatering;

b) cleaning;

c) drying.

12.2 Disposal of pipeline content

The Regulatory Authority should be consulted before any material is discharged from the pipeline.

Any drinking water plant within 1 km of the discharge point should be closed for the duration of the discharge and for 24 h thereafter.

12.3 Cleaning

Consideration should be given to the disposal of debris, and gels if used. Debris from the pipeline may block or contaminate small bore branches or instrument tappings. Consideration should be given to blocking off or removing these items.

12.4 Drying

Removal of residual water from a pipeline after dewatering should be considered in order to reduce corrosion or hydrate formation. One or more of the following drying methods may be employed:

a) propelling pigs through the pipeline by dry air or nitrogen;

b) passing a liquid drying agent (glycol or methanol) through the pipeline;

c) removing water vapour by vacuum pumps and purging with dry air or nitrogen.

Consideration should be given to the effects of drying chemicals or vacuum on seals of valves and pig traps.

An inert gas such as nitrogen should be used to separate methanol swabs and air. IGE/TD/1:1984 contains typical procedures for running methanol swabs.

If methanol is used attention should be given to its hazardous and toxic nature. Methanol has a low flashpoint and forms explosive mixtures with air, it is poisonous when breathed or swallowed and can be absorbed through skin contact.

In large quantities methanol and glycol can be harmful to marine life. Prior consent for disposal should be obtained (see **12.2**).

12.5 Introduction of product

For gas systems it is important to avoid formation of the potentially explosive mixture of hydrocarbon gas and air when a gas product is introduced into a pipeline. Dry inert gas should be used to purge the pipeline of air prior to the introduction of product.

The gas injection rate should be controlled to ensure that the gas temperature does not drop below allowable limits for the pipeline material or the dewpoint of the gas.

Consideration should be given to the introduction of inhibitors in the product stream to inhibit corrosion or prevent the formation of hydrates.

Pigs or spheres should be used to minimize mixing at the interface of a liquid product and water.

12.6 Connections to operating pipelines

Where it is necessary to commission a pipeline which is connected to an operating pipeline, two valve isolation with bleed should be provided.

In special circumstances a single valve with double block and bleed facilities may be sufficient.

Annex A (normative) Notation

The following symbols are used in this Part of BS 8010.

Symbol	Explanation	Unit
A	Cross section area of pipe wall	m^2
B	Weight of seawater displaced by pipe joint	N
C_D	Drag coefficient	ND
C_L	Lift coefficient	ND
C_M	Inertia coefficient	ND
C_P	Ovalization magnification factor accounting for pressure effects	ND
C_S	Slamming coefficient	ND
D	Total pipe outside diameter, including coatings and marine growth	m
D_i	Inside pipe diameter	m
D_o	Outside pipe diameter	m
D_{max}	Maximum outside diameter	m
D_{min}	Minimum outside diameter	m
E	Young's modulus for pipe wall material	N/m^2
F_D	Hydrodynamic drag force per unit length	N/m
F_I	Hydrodynamic inertia force per unit length	N/m
F_L	Hydrodynamic lift force per unit length	N/m
F_W	Wave slam force	N/m
F_s	Shear force	N
F_x	Axial force	N
F_y	Yield load	N
F_{xc}	Mean axial compressive load	N
F_{xe}	Effective axial force	N
H_B	Height of breaking wave	m
H_S	Significant wave height	m
H_{max}	Maximum wave height	m
L	Length of pipe joint	m
L_l	Length of cutback	m
M_c	Characteristic bending moment	N·m
M_P	Full plastic moment capacity of pipe cross section	N·m
N	Number of cycles at a particular stress range corresponding to fatigue failure	ND
P	External overpressure (buckling)	N/m^2
P_c	Characteristic external pressure (collapse)	N/m^2
P_d	Design pressure	N/m^2
P_e	Critical pressure for an elastic circular tube	N/m^2
P_i	Internal pressure	N/m^2
P_o	External pressure	N/m^2
P_p	Buckle propagation pressure	N/m^2
P_y	Yield pressure	N/m^2
P_{in}	Buckle initiation pressure	N/m^2
R	Radius of obstruction	m
SF	Stability safety factor	ND
T	Torque	N·m
T_d	Design temperature	°C
T_o	Temperature of pipe at installation	°C
T_s	Significant wave period	s
T_z	Zero crossing period	s
T_{max}	Period of the maximum wave	s
V_e	Fluid erosional velocity	m/s
V_i	Increased velocity	m/s
V_u	Uniform flow velocity	m/s
W_s	Submerged weight of pipeline per unit length	N/m
Z	Pipe section modulus	m^3
a	Wave induced water particle acceleration	m/s^2
f_d	Design factor (steel pipelines)	ND
f_f	Fatigue design factor	ND
f_m	Flexible pipe design factor (proof pressure)	ND
f_o	Initial ovalization	ND
f_p	Flexible pipe design factor (minimum burst pressure)	ND
m	Constant (of erosion)	$kg^{1/2}/m^{1/2}$ s

Symbol	Explanation	Unit
m_0	Zeroth spectral moment	m^2/s^2
m_2	Second spectral moment	m^2/s^2
n	Number of cycles at a particular stress range applied during the design life of the pipeline system	ND
t	Minimum wall thickness	m
t_{nom}	Nominal wall thickness	m
u	Water particle velocity normal to the pipe axis	m/s
z	Distance between centre line of the obstruction to point of measure	m
α	Coefficient of linear thermal expansion	$°C^{-1}$
ϵ_b	Bending strain	ND
ϵ_{bc}	Characteristic bending strain	
ϵ_c	Critical strain	ND
μ	Lateral soil friction coefficient	ND
v	Poisson's ratio for pipe wall material	ND
ϵ_p	Equivalent plastic strain	ND
ϵ_{ph}	Principle circumferential (hoop) strain	ND
ϵ_{pL}	Principle longitudinal plastic strain	ND
ϵ_{pr}	Principle radial plastic strain	ND
ρ	Density of seawater	kg/m^3
ρ_m	Fluid (contents) density	kg/m^3
σ_A	Allowable stress (hoop or equivalent)	N/m^2
σ_e	Equivalent stress (Von Mises)	N/m^2
σ_h	Hoop stress	N/m^2
σ_L	Longitudinal stress	N/m^2
σ_x	Axial stress	N/m^2
σ_{xo}	Initial stress in pipe	N/m^2
σ_y	Specified minimum yield stress	N/m^2
τ	Shear stress	N/m^2
τ_c	Characteristic torsional shear stress	N/m^2
τ_Y	Yield shear stress	N/m^2

Annex B (normative) Environmental considerations

B.1 Environmental factors

B.1.1 *Introduction*

The design of a subsea pipeline system is fundamentally dependent upon the loads and influences imposed by the natural environment. In designing the pipeline system to withstand both extreme and long term environmental effects, the following are required:

a) description of the characteristics of the natural environment in terms of defined and quantifiable parameters;

b) evaluation of the influence of these parameters upon the pipeline system.

Owing to the random element inherent in natural processes, statistical definitions and statistical analysis of measured data are important in defining many environmental parameters.

B.1.2 *Return periods*

The design return periods corresponding to the operational phase and construction phase should be specified.

The design return period for the normal operational phase should be not less than three times the design life or 100 years whichever is the shorter.

For the construction phase (see **4.2.2.2**) the design return period should be selected to take account of the expected duration of that phase and the consequences of exceeding the design conditions.

B.1.3 *Water depths*

Water depths along the pipeline route should be referred to a consistent datum. Elevation relative to the LAT is an acceptable datum.

Water depth variation due to the following should be considered:

a) astronomical tidal ranges;

b) surface waves;

c) wind and pressure induced storm surge effects.

These should be combined, taking account of the probability of their simultaneous occurrence, to give the most severe design water depth for each of the load cases given in **4.2.1**.

B.1.4 *Wind*

For exposed sections of a pipeline system, the design wind speed used in determining wind loads should be the three second gust speed corresponding to the design return period (see **B.1.2**). Variation of the gust wind speed with height should also be considered.

Wind should be assumed to be omnidirectional, unless adequate directional statistics are available.

Where there is no specific wind data available, design wind speeds may be calculated according to the method given in CP 3:Chapter V-2:1972.

B.1.5 ***Waves***

B.1.5.1 *General*

Wave information is required to determine the following:

a) extreme environmental loading;

b) long term fatigue loading;

c) installation activities and associated loadings;

d) operational activities and associated loadings.

Owing to the random characteristics of ocean wave behaviour, many aspects of the wave can only be expressed in statistical terms and evaluated by a statistical analysis obtained from measurements, observations or numerical models. Carter et al [28], Sarpkaya and Isaacson [29] and US Army CERC [30] give further information on the physical and theoretical principles involved.

Waves should be assumed to be omnidirectional unless adequate directional statistics are available.

B.1.5.2 *Wave parameters and their definitions*

B.1.5.2.1 Design sea state is the sea state expected to be equalled or exceeded once within the design return period.

B.1.5.2.2 Significant wave height, H_s, may be taken as equivalent to H_{m0} where:

$$H_{m0} = 4(m_0)^{½}$$

where

m_0 is the zeroth spectral moment which is equal to the variance on the sea surface elevation.

B.1.5.2.3 Significant wave period, T_s is the mean period of the highest one-third of all waves encountered within the design sea state. T_s may be taken as nearly equivalent to the zero upcrossing period T_z where:

$$T_Z \ (m_0/m_2)^{½}$$

where:

m_2 is the second spectral moment.

Usually the significant wave period $T_s = 1.24T_z$. See Bretschneider [31].

B.1.5.2.4 Maximum wave height, H_{max}, is the trough to crest height of the single wave which is expected to be equalled or exceeded once within the design return period.

B.1.5.2.5 Maximum wave period, T_{max}, is the period of the maximum wave.

NOTE In physical terms, the maximum wave characterizes the worst case individual wave, whilst the significant wave more closely characterizes the mean energy within the sea state as a whole.

B.1.5.3 *Extreme environmental loading*

The maximum wave corresponding to the design return period should be taken to define the extreme environmental wave loading.

Exceptions may be considered in cases where infrequent, transient, localized loading will not present a risk of failure. The significant wave or a spectral approach may be a more appropriate description of extreme conditions in such cases.

B.1.5.4 *Long term fatigue loading*

For the determination of fatigue loading, the following should be considered:

a) distribution of energy within the wave spectrum for a given sea state;

b) distribution of sea states throughout the design lifetime of the installation.

B.1.5.5 *Installation activities and associated loadings*

For the planning of installation activities, the following statistical information is required:

a) total percentage occurrence of sea states lying within the operational limits for the various installation activities;

b) duration of uninterrupted sea states lying within the operational limits for the various installation activities.

B.1.5.6 *Operational activities and associated loadings*

If the future operation of the pipeline is dependent upon weather-sensitive activities, then the feasibility of performing such activities should be considered at the design stage. The statistical information required is as given in **B.1.5.5** a) and b).

B.1.5.7 *Shallow water effects*

In nearshore areas and shoaling water, the seabed bathymetry and shoreline configuration may have a significant influence on the wave characteristics. Effects to be considered include the following:

a) refraction;

b) shoaling;

c) breaking;

d) diffraction;

e) reflection;

f) absorption;

g) longshore currents (see **B.1.6**).

If specific local data are not available, the changes in the wave characteristics may be determined by the application of suitable theories (see Sarpkaya and Isaacson [29] and US Army CERC [30]). These changes should be considered for the full range of water levels expected at the site.

B.1.5.8 *Wave induced water particle motion*

Water particle displacement, velocity and acceleration may be determined from the basic wave height, period data and water depth by applying an appropriate wave theory. The following effects should be considered when determining a suitable wave theory:

a) relationship between wave height, wave length and water depth;

b) possibility of wave breaking;

c) location(s) within the wave where information is required.

Carter et al [28], Sarpkaya and Isaacson [29] and Offshore installations. Guidance of design, construction and certification [32] provide guidance on the selection of suitable wave theories.

NOTE Approximate forms of wave theories should only be used with great care. For example, the deep water approximation to linear wave theory can result in significant errors when used to predict velocities close to the seabed.

B.1.6 ***Currents***

Design currents should be determined from statistical analysis of recorded data (assuming these are of sufficient duration) in combination with numerical model simulations.

Design current velocities should include the contributions from all significant constituent components. These include the following:

a) tidal;

b) wind induced;

c) storm surge;

d) ocean circulations;

e) density currents;

f) river discharge;

g) longshore currents.

The components should be combined, taking account of the probability of their simultaneous occurrence for each load case considered.

The current velocity and direction should be determined for the selected return periods (see **B.1.2**). Where no directional data are available, it should be assumed that the direction of the design current is normal to the pipeline.

The variation of current velocity with water depth and adjacent structures should be taken into account.

In the case of two risers or a riser adjacent to a jacket leg, the water velocity amplification, V_i, of one due to the proximity of the other is generally given by the following equation:

$$V_i = V_u\left(1 + \frac{R^2}{z^2}\right)$$

where

V_i is the increased velocity in metres per second;

V_u is the uniform flow velocity in metres per second;

R is the radius of obstruction in metres;

z is the distance between the centre line of the obstruction to the point of measurement in metres.

Detailed analysis may be necessary when more than two risers are in close proximity.

B.1.7 ***Air and sea temperatures***

B.1.7.1 *General*

The maximum and minimum air and sea temperatures that are likely to be encountered during the design life of the pipeline system should be established.

B.1.7.2 *Air temperatures*

Where specific data are not available, minimum air temperatures for design purposes in the UK sector of the North Sea are as follows:

North of 54° N Latitude – 10 °C;

South of 54° N Latitude – 6 °C.

In areas close to land, consideration should be given to the possibility of encountering lower temperatures than the minimum.

B.1.7.3 *Sea temperatures*

Where specific data are not available, a minimum sea temperature for design purposes in the UK sector of the North Sea should be taken as 0 °C. Possible differences in design sea temperature between the surface and the seabed should be considered.

B.1.8 ***Marine growth***

Marine growth increases the cross-sectional area and alters the surface characteristics of a pipe. These effects should be taken into account when designing the pipeline system.

The expected extent of marine growth should be established and applied in the design analysis. Once the pipeline system is in place, the extent of marine growth should be monitored and the design revalidated if the design thickness is exceeded. Oldfield [33] provides guidance in determining the likely extent of marine growth for particular areas. Offshore installations. Guidance of design, construction and certification [32] also gives additional guidance.

In performing the design analysis, the effects of marine growth should be considered in relation to the following:

a) increased diameter;

b) increased drag coefficient;

c) increased mass;

d) increased hydrodynamic added mass;

e) effect on inspection programmes;

f) corrosion implications.

B.1.9 ***Seabed soils***

The following seabed soil information is typically required:

a) soil type;

b) grain size distribution;

c) presence and size of boulders;

d) shear strength, angle of internal friction and cohesion;

e) water content;

f) liquid and plastic limits;

g) bulk density;

h) oxygen content, salinity and organic content;

i) presence of hydrogen sulphide, producing bacteria;

j) electrical resistivity;

k) thermal conductivity;

l) historical records of bed movement and storm effects.

Seabed soil information is used to evaluate the following:

1) seabed friction;

2) seabed bearing capacity;

3) scour and spanning potential;

4) movement of sandwaves and other bedforms;

5) natural backfill potential;

6) self burial potential;

7) liquefaction;

8) flotation;

9) slope stability;

10) corrosion and cathodic protection;

11) heat loss from buried lines.

B.1.10 ***Seismic action***

The possibility of seismic action on or near the pipeline system should be evaluated. The amplitude, velocity and acceleration of ground movement should be determined.

Seismically-induced shock pressure waves in the surrounding seawater and the possibility of soil liquefaction should also be evaluated.

B.2 Environmental loads

B.2.1 ***General***

The environmental factors described in **B.1** impose a range of influences upon a pipeline system. Their combined influence should be evaluated by superimposing component effects, taking into account the probability of their simultaneous occurrence.

Directional effects should be considered where relevant. Where there is insufficient directional data available, loads should be applied to the pipeline system from the direction, or combination of directions, that produces the most severe condition.

B.2.2 ***Hydrostatic loading***

When determining the hydrostatic load for a given design aspect, the water depth selected should lead to the most severe loading condition (see **B.1.3**). The effect of surface waves should be considered.

B.2.3 ***Wind loads***

Wind loads acting on a pipe produce two effects as follows:

a) direct static loads, that are assumed to act normal to the pipe;

b) vortex shedding, caused by unsteady flow patterns around the pipe.

Vortex shedding is discussed in **B.2.5**.

The static wind load should be determined in accordance with CP3:Chapter V-2:1972.

The total outside diameter of the pipe should include all coatings plus any additional accumulations on the pipe surface such as marine growth and ice.

B.2.4 ***Hydrodynamic loads***

B.2.4.1 *General*

Hydrodynamic loads include the following:

a) direct hydrodynamic loads;

b) wave slam;

c) shock pressure from breaking waves.

B.2.4.2 *Direct hydrodynamic loads*

Direct hydrodynamic loads are the result of water particle flow around the pipe from both current and wave effects. The loads include the following:

a) drag force (F_D);

b) inertia force (F_I);

c) lift force (F_L).

For the determination of wave loads, the following principal calculation approaches exist.

1) *Deterministic approach,* in which the properties of a sea state are characterized by a statistically derived design wave. The water particle motions induced by the design wave are calculated using an appropriate wave theory (see **B.1.5.8**). Hydrodynamic loads corresponding to the design wave are then calculated.

2) *Statistical approach,* in which the properties of a sea state are described in terms of spectral distribution. Using linear wave theory, corresponding spectral distributions of wave-induced water particle motion are developed, from which a resulting force distribution is derived. See Sarpkaya and Isaacson [29] for details of this type of approach. Practical application of a statistical approach requires the use of specialized computer software.

For a given water particle velocity and acceleration, the direct hydrodynamic loads per unit length of the pipeline in newtons per metres may be calculated using the following equations:

$$F_D = \tfrac{1}{2}\rho C_D D u \,|\, u \,|$$

$$F_L = \tfrac{1}{2}\rho C_L D u^2$$

$$F_I = C_M \rho \alpha \pi D^2/4$$

where

ρ is the mass density of the surrounding water (in kilogrammes per cubic metre);

D is the total pipeline outside diameter, including coatings and any marine growth (in metres);

u is the water particle velocity normal to the pipe axis, incorporating the components due to both wave action and steady current (in metres per second);

a is the wave induced water particle acceleration normal to the pipe axis (in metres per square second);

C_D is the drag coefficient;

C_M is the inertia coefficient;

C_L is the lift coefficient.

Unless a more precise method is used, wave induced water particle velocity components may be combined with steady current (see **B.1.6**) components by vectorial addition. All velocity components should be combined before calculating the hydrodynamic forces.

NOTE 1 Wave induced water particle motion is dependent upon the phase angle of the wave. Phase differences exist between the following parameters:

a) velocity and acceleration components;

b) horizontal and vertical flow components.

The phase angle should be selected to give the worst case vectorial combination of force components.

Values of the hydrodynamic force coefficients, C_D, C_M, and C_L are dependent upon the following:

i) Reynolds number;

ii) Keulegan Carpenter number;

iii) relative surface roughness of the pipeline;

iv) separation distance of the pipeline from a solid boundary;

v) degree of embedment of the pipeline;

vi) relative magnitudes of wave induced and steady current water particle velocity components.

If the pipe is adjacent to another structure or forms one of a number of closely spaced pipes, consideration has to be given to possible interaction and solidification effects. Where the adjacent structure is relatively large, such as a concrete platform or a jacket leg, consideration should also be given to the effect of increased particle velocities and accelerations resulting from the modified flow regime.

Care should be taken when selecting hydrodynamic coefficients to ensure that all assumptions are compatible and the calculations carried out follow one consistent logical course.

NOTE 2 DnV Rules for design and installation of submarine pipelines [34] has been found to yield acceptable results. Further guidance may be found in DHI Design guidelines for spanning of pipelines [35].

B.2.4.3 *Wave slam*

A horizontal length of pipe in the splash zone may experience wave slamming forces caused by sudden immersion of the pipe during the passage of a wave. The slamming force F_W per unit length in newtons per metre in the direction of the velocity is calculated using the following equation:

$$F_W = \frac{1}{2}\rho C_S D u^2$$

where

ρ is the water mass density (in kilogrammes per cubic metre);

C_S is the slamming coefficient;

D is the total pipeline outside diameter including coatings and marine growth (in metres);

u is the velocity of water surface normal to the pipe surface, (water surface vertical velocity) (in metres per second)

The slamming coefficient C_S should not be taken as less than 3.0 for smooth circular cylinders.

Dynamic amplification should also be taken into account when considering the response stresses. For a pipe fixed at both ends, the following dynamic amplification factors are recommended:

a) end moments: 1.5;

b) midspan moment: 2.0.

The fatigue damage due to wave slamming should also be taken into account and added to the fatigue contribution from other variable loads.

B.2.4.4 *Shock pressure from breaking waves*

Shock pressure is a local pressure on the face of the pipe, produced when the breaking wave meets a pipe. Unless more precise data are available, the force may be determined by the application of the equation given in **B.2.4.3** where C_S = 3.0 and the area is determined as follows (see Figure B.1):

a) width is equal to a sector ± 22.5°; measured from the wave direction;

b) height is equal to $H_B/4$ where H_B is the height of the characteristic breaking wave.

The impact velocity should be calculated as the maximum velocity in the breaking wave.

The force from the breaking wave should be applied between the still water level and the wave crest to give the most critical loading.

B.2.5 *Flow-induced cyclic loads*

Fluid flow past unsupported pipeline or riser spans can cause fluctuating pressure forces due to vortex shedding which may lead to resonant vibrations of the pipe. Vortex induced span vibration is of principal concern for submarine sections of the pipeline system, but the possibility of wind-induced vibration of exposed riser spans should also be considered.

For the evaluation of wind-induced vibration of exposed riser spans, see ESDU No. 78006 [36].

B.2.6 *Platform movement*

Platform movements impose loadings on risers and adjacent sections of pipeline. Sources of platform movement include the following:

a) elastic movement of fixed and floating platforms due to wave, current and wind effects;

b) immediate soil deformation due to installation of a fixed platform;

c) long term soil settlement under and around a fixed platform.

Elastic platform movement should be determined under the design storm conditions.

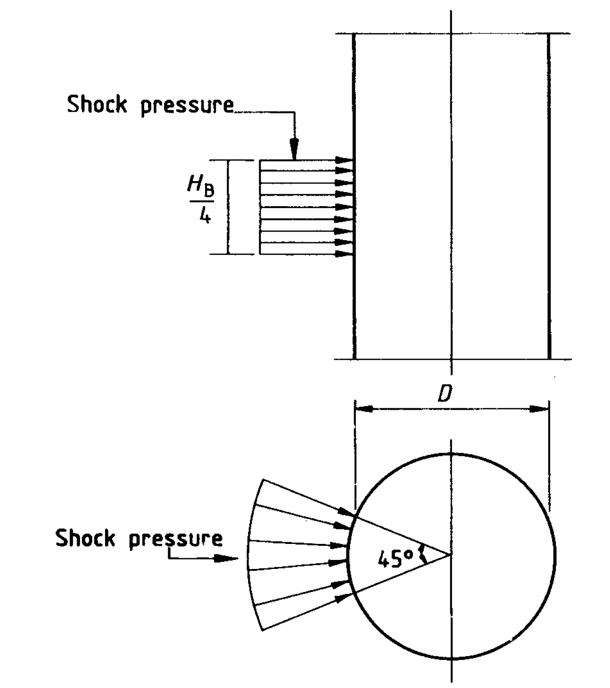

Figure B.1 — Area to be investigated when calculating the shock pressure

B.2.7 *Soil related effects*

B.2.7.1 *General*

Parameters used in design should be determined under a soil survey (see **B.1.9**).

B.2.7.2 *Resistance to movement*

The resistance of a pipeline to movement over the seabed has a number of important design implications. These include the following:

a) pipeline stability;

b) pipeline expansion movement;

c) installation by pull or on-bottom tow methods.

The design procedure should consider all relevant aspects and determine an appropriate theory for seabed resistance calculation.

NOTE It is a commonly accepted practice to express the soil resistance force as the product of the coefficient of soil friction and pipe submerged weight.

It should be noted, however, that this approach generally represents an empirical simplification rather than an accurate description of the physical pipe/seabed interaction mechanisms. The following demonstrate this point.

1) *For cohesive soils,* the sliding resistance is primarily dependent upon the surface contact area between the pipeline and the soil. This relates indirectly to pipe submerged weight, since the surface contact area is a function of pipe embedment.

2) *For rocky seabeds,* the lateral restraint may be due to mechanical interlocking between the pipeline and the rocks and hence unrelated to sliding friction effects.

The characteristics of the seabed should therefore be examined for each individual case, and the implications with regard to resistance to pipeline movement should be established.

For simple situations, e.g. relatively flat seabeds with a well defined soil type, it may be possible to define an effective coefficient of friction which reasonably represents the soil resistance to pipeline movement. The values in Table B.1 have been used in the past for North Sea applications and may be used with caution for similar conditions.

Table B.1 — Typical effective coefficients of friction for North Sea applications

	Lateral friction		Axial friction	
	Min.	Max.	Min.	Max.
Non-cohesive (e.g. sand)	0.5	0.9	0.55	1.2
Cohesive (e.g. clay, silt)	0.3	0.75	0.3	1.0

B.2.7.3 *Bearing capacity*

Soil bearing capacity should be evaluated using soil mechanics theory applied to the results of in situ tests.

B.2.7.4 *Sediment transport effects*

In areas of non-cohesive seabed soils, the following sediment transport related processes may take place:

a) scour formation around pipeline and other installations;

b) movement of sandwaves and other bedforms;

c) natural backfill;

d) self-burial.

In all cases, the potentially adverse consequences of these effects should be evaluated. In some cases natural backfill and self-burial may be beneficial in allowing artificial backfill and burial operations to be avoided.

These effects may be evaluated using loose bed transport theory to determine the relative rates of erosion and deposition of seabed soil around the pipeline or installation. Randkivi [37] details the theoretical principles involved. Gravesen and Fredsoe [38] suggest possible approaches for the evaluation of sediment transport related effects.

B.2.7.5 *Liquefaction*

Cohesionless soils existing in a metastable grain structure may be subject to spontaneous liquefaction when subjected to a shearing disturbance. Possible sources of disturbance include the following:

a) wave action;

b) seismic action;

c) tidal action;

d) river discharge.

Evaluation of liquefaction effects should consider the relative rates of pore water pressure build up and dissipation within the soil. Gravesen and Fredsoe [38] give further information on methods of evaluating liquefaction effects.

B.2.7.6 *Slope stability*

Seabed survey data should be examined for evidence of slope instability on or near the pipeline route. The following should also be considered:

a) presence of triggering effects such as waves or seismic action;

b) sediment transport processes leading to deposition at the top of the slope or erosion near the base.

Annex C (normative) Buckling

C.1 Local buckling

C.1.1 *General*

Local buckling of the pipe wall may be avoided if the various loads to which the pipe is subjected are less than the characteristic values in **C.1.2** to **C.1.7**.

C.1.2 *External pressure*

The characteristic value, P_c, required to cause collapse when the external pressure is acting alone, may be obtained from the following equations:

$$\left\{\left(\frac{P_c}{P_e}\right) - 1\right\}\left\{\left(\frac{P_c}{P_y}\right)^2 - 1\right\} = 2\,\frac{P_c}{P_y}\left\{\left(f_o\,\frac{D_o}{t_{nom}}\right)\right\} \qquad \text{(C.1)}$$

$$P_e = \frac{2E}{(1 - v^2)}\left(\frac{t_{nom}}{D_o}\right)^3 \qquad \text{(C.2)}$$

$$P_y = 2\sigma_y\,\frac{t_{nom}}{D_o} \qquad \text{(C.3)}$$

$$f_o = \frac{D_{max} - D_{min}}{D_{max} + D_{min}} \qquad \text{(C.4)}$$

where

- P_e is the critical pressure for an elastic circular tube (in newtons per square metre);
- P_y is the yield pressure (in newtons per square metre);
- f_o is the initial ovalization of the pipe cross section (not to be taken as less than 0.025);
- P_c is the characteristic external pressure (in newtons per square metre);
- σ_y is the specified minimum yield stress of the pipe wall material (in newtons per square metre);
- v is the Poisson's ratio for the pipe wall material;
- t_{nom} is the nominal wall thickness (in metres);
- E is the Young's modulus for the pipe wall material (in newtons per square metre);
- D_o is the outside diameter (in metres).

NOTE See also Murphy and Langer [39].

C.1.3 *Axial compression*

If *D*/*t* is less than 60, local buckling under axial compression does not occur until the mean axial compression load, F_{xc}, reaches the yield load, F_y, i.e. as in the following equations:

$$F_{xc} = F_y \qquad \text{(C.5)}$$

where

$$F_y = \pi(D_o - t_{nom})t_{nom}\sigma_y$$

C.1.4 *Bending*

The characteristic bending moment value, M_c, required to cause buckling when bending moments are acting alone, may be obtained from the following equations:

$$\frac{M_c}{M_p} = 1 - 0.0024\frac{D_o}{t_{nom}} \qquad \text{(C.6)}$$

and

$$M_p = (D_o - t_{nom})^2 t\sigma_y \qquad \text{(C.7)}$$

where

M_p is the fully plastic moment capacity of the pipe cross section (in newton metres).

The characteristic bending strain, ϵ_{bc}, at which buckling due to bending moments acting alone occurs, may be obtained from the following equation:

$$\epsilon_{bc} = 15\left(\frac{t_{nom}}{D_o}\right)^2 \qquad \text{(C.8)}$$

C.1.5 *Torsion*

The characteristic value, τ_c, required to cause buckling when torsion is acting alone, may be obtained from the following equations:

$$\begin{aligned} \tau_c/\tau_y &= 0.542 && \text{for } a_\tau < 1.5 \\ \tau_c/\tau_y &= 0.813 + 0.68(a_\tau - 1.5)^{1/2} && \text{for } a_\tau < 9 \\ \tau_c/\tau_y &= 1 && \text{for } a_\tau > 9 \end{aligned} \qquad \text{(C.9)}$$

and

$$\tau_y = \sigma_y/(3)^{\frac{1}{2}} \qquad \text{(C.10)}$$

where

τ_y is the yield shear stress

and

$$a_\tau = \frac{E}{\tau_y}\left(\frac{t_{nom}}{D_o}\right)^{\frac{3}{2}} \qquad \text{(C.11)}$$

C.1.6 *Load combinations*

The maximum external over pressure, P, in the presence of axial force, F_x, and/or bending moment, M, when f_o is less than 0.025 may be obtained from the following equation:

$$\{(M/M_c) + (F_x/F_{xc})\}^n + (P/P_c) = 1 \qquad \text{(C.12)}$$

where

$$n = 1 + 300\frac{t_{nom}}{D_o}$$

t_{nom} is the nominal wall thickness (in metres);

D_o is the outside diameter (in metres).

Characteristic loads P_c, F_{xc} and M_c can be obtained from equations (C.1), (C.5), (C.6) and (C.7) respectively.

C.1.7 *Strain criteria*

The bending strain, ϵ_b, required to cause buckling, in the presence of external overpressure, P, may be obtained from:

$$\frac{\epsilon_b}{\epsilon_{bc}} + \frac{P}{P_c} = 1 \qquad \text{(C.13)}$$

where ϵ_{bc} and P_c may be obtained from equations (C.8) and (C.1) respectively.

C.2 Propagation buckling

The potential for a pipeline to propagate local buckles is dependent on the external overpressure P, and its relationship with the propagation pressure P_p.

The external overpressure, P, is given by the following equation:

$$P = P_o - P_i \qquad \text{(C.14)}$$

where

P_o is the external pressure (in newtons per square metre);

P_i is the internal pressure (in newtons per square metre).

The propagation pressure, P_p, is given by the following equation:

$$P_p = 10.7\sigma_y(t_{nom}/D_o)^{9/4} \qquad \text{(C.15)}$$

If P is less than P_p, then, even though the pipe may develop a local buckle, the buckle will not propagate.

If P is greater than or equal to P_p and a local buckle or local damage has occurred, then the pipeline is likely to undergo propagation buckling. Consideration should be given to the provision of buckle arresters at strategic locations along the pipeline to limit the amount of pipeline damaged by a propagated buckle.

C.3 Ovalization

The total ovalization, f, of a pipe due to the combined effects of unidirectional bending and external pressure may be obtained from the following equation:

$$f = C_p\left\{C_f\left(\frac{D_o}{t_{nom}}\epsilon_b\right)^2 + f_o\right\} \qquad \text{(C.16)}$$

where

C_f is $0.06\{1 + D_o/(120t_{nom})\}$;

C_p is the magnification factor accounting for pressure effects = $1/(1 - P/P_e)$;

ϵ_b is the maximum bending strain;

f_o is the initial ovalization;

P_e and f_o are obtained from equations (C.2) and (C.4) respectively.

NOTE If cyclic or reversed bending is applied, the resulting ovalization may be considerably greater than that predicted by the equation.

List of references (see 1.2)

Normative references

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