INTERNATIONAL STANDARD

ISO 15589-2

Second edition
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Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems —

Part 2:
Offshore pipelines

Industries du pétrole, de la pétrochimie et du gaz naturel — Protection cathodique des systèmes de transport par conduites —

Partie 2: Conduites en mer

Reference number
ISO 15589-2:2012(E)

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Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 2.

The main task of technical committees is to prepare International Standards. Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights.

ISO 15589-2 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offhore structures for petroleum, petrochemical and natural gas industries*, Subcommittee SC 2, *Pipeline transportation systems*.

This second edition cancels and replaces the first edition (ISO 15589-2:2004), which has been technically revised as follows:

- In Clause 6 recommendations for isolating joints are included.
- In Clause 7 a subclause on hydrogen-induced stress cracking evaluation is included.
- In Clause 7 coating breakdown factors have been reorganized by splitting into “with” and “without” concrete coating. More conservative values for some coating systems have been selected based on feedback from daily practice in industry.
- In Clause 8 recommendations on anode electrochemical properties for seawater with low salinity are included.
- Design values for electrochemical capacity in Clause 8 have been reduced. Higher values are permitted if properly documented.
- Quality control of anodes has been adjusted regarding tolerances, straightness, mass, surface irregularities and cracking (Clause 10).
- The guidance on attenuation calculation has been significantly extended. A new Annex B has been introduced and includes several examples and alternative methods.
- Regarding anode testing, only free-running testing is accepted (see Annex C).

ISO 15589 consists of the following parts, under the general title *Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems*:

- *Part 1: On-land pipelines*
- *Part 2: Offshore pipelines*

Introduction

The technical revision of this part of ISO 15589 has been carried out in order to accommodate the needs of industry and to move this International Standard to a higher level of service within the petroleum, petrochemical and natural gas industry.

Pipeline cathodic protection is achieved by the supply of sufficient direct current to the external pipe surface, so that the steel-to-electrolyte potential is lowered on all the surface to values at which external corrosion is reduced to an insignificant rate.

Cathodic protection is normally used in combination with a suitable protective coating system to protect the external surfaces of steel pipelines from corrosion.

Users of this part of ISO 15589 should be aware that further or differing requirements may be needed for individual applications. This part of ISO 15589 is not intended to prevent alternative equipment or engineering solutions from being used for individual applications. This may be particularly applicable where there is innovative or developing technology. Where an alternative is offered, it is intended that any variations from this part of ISO 15589 be identified and documented.

This part of ISO 15589 can also be used for offshore pipelines outside the petroleum, petrochemical and natural gas industries.

INTERNATIONAL STANDARD **ISO 15589-2:2012(E)**

Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems —

Part 2:
Offshore pipelines

1 Scope

This part of ISO 15589 specifies requirements and gives recommendations for the pre-installation surveys, design, materials, equipment, fabrication, installation, commissioning, operation, inspection and maintenance of cathodic protection (CP) systems for offshore pipelines for the petroleum, petrochemical and natural gas industries as defined in ISO 13623.

This part of ISO 15589 is applicable to carbon steel, stainless steel and flexible pipelines in offshore service.

This part of ISO 15589 is applicable to retrofits, modifications and repairs made to existing pipeline systems.

This part of ISO 15589 is applicable to all types of seawater and seabed environments encountered in submerged conditions and on risers up to mean water level.

2 Normative references

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

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

ISO 8044, *Corrosion of metals and alloys — Basic terms and definitions*

ISO 8501-1, *Preparation of steel substrates before application of paints and related products — Visual assessment of surface cleanliness — Part 1: Rust grades and preparation grades of uncoated steel substrates and of steel substrates after overall removal of previous coatings*

ISO 9606-1, *Qualification testing of welders — Fusion welding — Part 1: Steels*

ISO 13623, *Petroleum and natural gas industries — Pipeline transportation systems*

ISO 15589-1, *Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline transportation systems — Part 1: On-land pipelines*

ISO 15607, *Specification and qualification of welding procedures for metallic materials — General rules*

ASTM D1141[1], *Standard Practice for the Preparation of Substitute Ocean Water*

AWS D1.1/D1.1M[2], *Structural Welding Code — Steel*

EN 10025 (all parts)[3], *Hot rolled products of structural steels*

EN 10204:2004, *Metallic products — Types of inspection documents*

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[1] American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, USA.

[2] American Welding Society, 550 NW Le Jeune Road, Miami, FL 33126, USA.

[3] European Committee for Standardization, Management Centre, Avenue Marnix 17, B-1000, Brussels, Belgium.

3 Terms and definitions

For the purposes of this document, the terms and definitions given in ISO 8044 and the following apply.

3.1
anode potential
anode-to-electrolyte potential

3.2
anode sled
anodes installed on a structure and connected to the pipeline by a cable

3.3
closed-circuit anode potential
anode potential while electrically linked to the pipeline to be protected

3.4
coating breakdown factor
f_C
ratio of current density required to polarize a coated steel surface as compared to a bare steel surface

3.5
cold shut
horizontal surface discontinuity caused by solidification of the meniscus of the partially cast anodes as a result of interrupted flow of the casting stream

3.6
driving voltage
difference between the pipeline/electrolyte potential and the anode/electrolyte potential when the cathodic protection is operating

3.7
electric field gradient
change in electrical potential per unit distance through a conductive medium, arising from the flow of electric current

3.8
electrochemical capacity
ε
total amount of electric charge that is produced when a fixed mass (usually 1 kg) of anode material is consumed electrochemically

NOTE Electrochemical capacity is expressed in ampere hours.

3.9
final current density
estimated current density at the end of the lifetime of the pipeline

NOTE Final current density is expressed in amperes per square metre.

3.10
hydrogen-induced stress cracking
HISC
cracking due to a combination of load and hydrogen embrittlement caused by the ingress of hydrogen formed at the steel surface due to the cathodic polarization

3.11
IR drop
voltage due to any current, measured between two points of the metal of the pipe or two points of the electrolyte, such as seawater or seabed, in accordance with Ohm's law

NOTE IR drop and electric field gradient are related terms.

3.12
master reference electrode
reference electrode, calibrated with the primary calibration reference electrode, used for verification of reference electrodes that are used for field or laboratory measurements

3.13
mean current density
estimated average cathodic current density for the entire lifetime of the pipeline

NOTE Mean current density is expressed in amperes per square metre.

3.14
protection potential
structure-to-electrolyte potential for which the metal corrosion rate is considered as insignificant

3.15
pitting resistance equivalent number
PREN

number, developed to reflect and predict the pitting resistance of a stainless steel, based on the proportions of Cr, Mo, W and N in the chemical composition of the alloy

3.16
primary calibration reference electrode
reference electrode used for calibration of master reference electrodes

3.17
remotely operated vehicle
ROV

underwater vehicle operated remotely from a surface vessel or installation

[ISO 14723]

3.18
riser
part of an offshore pipeline, including any subsea spool pieces, which extends from the seabed to the pipeline termination point on an offshore installation

[ISO 13623]

3.19
utilization factor
$\boldsymbol{\mu}$

fraction of the anodic material weight of a galvanic anode that can be consumed before the anode ceases to provide the minimum required current output

4 Symbols and abbreviated terms

4.1 Symbols

ε	electrochemical capacity
f_c	coating breakdown factor
μ	utilization factor

4.2 Abbreviated terms

CAT	cold-applied tape
CE	carbon equivalent
CP	cathodic protection
CRA	corrosion-resistant alloy
EPDM	ethylene propylene diene monomer
FBE	fusion-bonded epoxy
HISC	hydrogen-induced stress cracking
HSS	heat-shrinkable sleeve
PE	polyethylene
PP	polypropylene
PREN	pitting resistance equivalent number
PU	polyurethane
ROV	remotely operated vehicle
SCE	saturated calomel electrode
SMYS	specified minimum yield strength
SRB	sulphate reducing bacteria
3LPE	three-layer polyethylene
3LPP	three-layer polypropylene

5 General

5.1 Competence assurance

Personnel who undertake the design, supervision of installation, commissioning, supervision of operation, measurements, monitoring and supervision of maintenance of cathodic protection systems shall have the appropriate level of competence for the tasks undertaken.

NOTE 1 EN 15257 or the NACE Cathodic Protection Training and Certification Programme constitute suitable methods that can be used to assess competence of cathodic protection personnel.

NOTE 2 Competence of cathodic protection personnel to the appropriate level for tasks undertaken can be demonstrated by certification in accordance with prequalification procedures such as EN 15257, the NACE Cathodic Protection Training and Certification Programme or any other equivalent scheme.

5.2 Compliance

A quality system and an environmental management system should be applied to assist compliance with the requirements of this part of ISO 15589.

NOTE ISO/TS 29001 gives sector-specific guidance on quality management systems and ISO 14001 gives guidance on the selection and use of an environmental management system.

6 Cathodic protection system requirements

6.1 General

The CP system shall be designed to prevent external corrosion over the design life of the pipeline and to:

- provide sufficient current to the pipeline to be protected and distribute this current so that the selected criteria for CP are effectively attained on the entire surface;
- provide a design life of the anode system commensurate with the required life of the protected pipeline, or to provide for periodic rehabilitation of the anode system;
- provide adequate allowance for anticipated changes in current requirements with time;
- ensure that anodes are installed where the possibility of disturbance or damage is minimal;
- provide adequate monitoring facilities to test and evaluate the system's performance.

The CP system shall be designed with due regard to environmental conditions and neighbouring structures.

Offshore pipelines that are protected by galvanic anode systems should be electrically isolated from other pipelines and structures that are protected by impressed-current systems. Offshore pipelines shall be isolated from other unprotected or less protected structures, which could drain current from the pipeline's CP system. If isolation is not practical or stray current problems are suspected, electrical continuity should be ensured.

Care shall be taken to ensure that different CP systems of adjacent pipelines or structures are compatible and that no excessive current drains from one system into an adjacent system.

The pipeline CP design shall take into account the pipeline installation method, the types of pipeline and riser, and the burial and stabilization methods proposed. Further guidance is given in Annex G.

The CP system based on galvanic anodes shall be designed for the lifetime of the pipeline system using the calculation procedure given in Annex A.

For areas with high water velocities and areas with erosion effects (e.g. from entrained sand, silt, ice particles), the design of the CP system needs special attention and additional design criteria shall be considered.

Installation of permanent test facilities should be considered, taking into account specific parameters such as pipeline length, water depth and underwater access related to the burial conditions.

ISO 15589-1 should be used for the cathodic protection of short lengths of offshore pipelines and their branches that are directly connected to cathodically protected onshore pipelines.

6.2 Selection of CP systems

6.2.1 General

CP shall be achieved using either galvanic anodes or an impressed-current system. Galvanic anodes shall be connected to the pipe, either individually or in groups

NOTE 1 Galvanic anodes are limited in current output by the anode-to-pipe driving voltage and the electrolyte resistivity. Generally, anodes are attached directly to the pipe as bracelets. Sleds of anodes can also be placed at regular intervals along the pipeline.

NOTE 2 Some pipelines can be protected by anodes located at each end. Typically, this type of installation is used on inter-platform pipelines. Anodes for the pipeline can be attached to the platform if the pipeline is electrically connected to the platform.

Items that shall be considered in selecting the system to be used are covered in 6.2.2.

6.2.2 System selection considerations

Selection of the CP system shall be based on the following considerations:

- magnitude of the protective current required;
- resistivity of the seawater;
- availability and location of suitable power sources for impressed-current systems;
- existence of any stray currents causing significant potential fluctuations between pipeline and earth that can preclude the use of galvanic anodes;
- effects of any CP interference currents on adjacent structures that might limit the use of impressed-current CP systems;
- limitations on the space available, due to the proximity of foreign structures, and related construction and maintenance concerns;
- future development of the area and any anticipated future extensions to the pipeline system;
- cost of installation, operation and maintenance;
- reliability of the overall system;
- integrity of other pipelines and/or structures existing in the same area that could be affected by impressed-current systems unless proper measures are taken to prevent these effects.

NOTE Impressed-current systems can be preferred on short pipelines which terminate at platforms that have impressed-current systems installed or where an impressed-current system is operated from the shore. Impressed-current systems can also be preferred as a retrofit system on pipelines with galvanic anode failures, excessive anode consumption, operation beyond original design life or excessive coating deterioration. Impressed current can also be the preferred method for high-resistivity water.

6.3 Isolating joints

Isolating joints should be considered at the following locations:

- at connections to onshore pipelines or onshore receiving facilities;

- at connections to pipelines that require different protection criteria;
- between cathodically protected pipelines and non-protected facilities or less protected facilities;
- between pipeline systems (or structures) protected by impressed current and galvanic anodes.

If isolating joints are used they shall be designed and installed to ensure long-term integrity and shall be positioned to allow easy access for inspection and maintenance. Detailed design requirements are given in ISO 15589-1.

7 Design parameters

7.1 General

The design of a pipeline CP system shall be based on:

- detailed information on the pipeline to be protected, including material, length, wall thickness, outside diameter, pipe-laying procedures, route, laying conditions on the sea bottom, temperature profile (operating and shut in) along its whole length, type and thickness of corrosion-protective coating(s) for pipes and fittings, presence, type and thickness of thermal insulation, mechanical protection and/or weight coating;
- environmental conditions, including diurnal and seasonal variations, such as seawater salinity, temperature and resistivity, tides and seabed resistivity along the whole length of the pipeline;
- burial status (extent of backfilling after trenching or natural burial) and soil resistivity;
- design life of the system;
- information on existing pipelines in close proximity to or crossing the new pipeline, including location, ownership and corrosion-control practices;
- information on existing CP systems (platforms, landfalls, subsea structures, etc.) and electrical pipeline isolation;
- availability of electrical power, electrical isolating devices, electrical bonds;
- applicable local legislation;
- construction dates, start-up date (required for hot lines);
- presence of fittings, J-tubes, risers, clamps, wyes, tees and other appurtenances; and
- performance data on CP systems in the same environment.

If CP performance data for similar environments is not available (for example when moving into deeper water), data on the seawater characteristics (dissolved oxygen, salinity, pH, sea currents, and fouling) shall be obtained as these can affect cathodic polarization and calcareous deposit formation. For these situations, the required information shall be obtained from field surveys and/or corrosion test data including the following:

- protective current requirements to meet applicable criteria;
- electrical resistivity of the electrolyte, including seasonal changes if relevant;
- pipe burial depth (if buried) and identification of exposed span lengths and locations;
- water temperature at the seabed;
- oxygen concentration at the seabed;
- water flow rate at the seabed, including seasonal changes if relevant;

- seabed topography.

When reviewing operating experience, the following additional data should be considered:

- electrical continuity;
- electrical isolation;
- external coating integrity;
- deviation from specifications;
- maintenance and operating data.

Design procedures for the CP based on galvanic anode systems shall be in accordance with Annex A.

7.2 Protection potentials

7.2.1 Potential criteria

To ensure that adequate CP of a pipeline is being achieved, the measured potential shall be in accordance with Table 1.

NOTE 1 The effectiveness of CP or other external corrosion-control measures can be confirmed by direct measurement of the pipeline potential. However, visual observations of progressive coating deterioration and/or corrosion, for example, are indicators of possible inadequate protection. Physical measurements of a loss of pipe wall thickness, using divers, or using internal inspection devices such as intelligent pigs, can also indicate deficiencies in the level of corrosion protection.

Table 1 — Potential criteria

Materials	**Minimum negative potential** V	**Maximum negative potential**[a] V
Carbon steels		
Immersed in seawater	– 0,80	– 1,10[b]
Buried in sediments	– 0,90[f]	– 1,10[b]
Austenitic stainless steels[g]		
PREN ≥ 40[c]	– 0,30[d]	– 1,10
PREN < 40[c]	– 0,50[d]	– 1,10
Duplex stainless steels	– 0,50[d]	[e]
Martensitic stainless (13 % Cr) **steels**	– 0,50[d]	[e]

The potentials are referenced to an SCE reference electrode, which are equivalent to a silver/silver chloride reference electrode (Ag/AgCl/seawater) in 30 Ω·cm seawater.

[a] These negative limits also ensure negligible impact of CP on pipeline coatings.

[b] Where pipeline systems are fabricated from high-strength steel (SMYS > 550 MPa), the most negative potential that can be tolerated without causing hydrogen embrittlement shall be ascertained.

[c] *PREN* = %Cr + 3,3 %(Mo+0,5W) + 16 %N.

[d] For stainless steels, the minimum negative potentials apply for aerobic and anaerobic conditions.

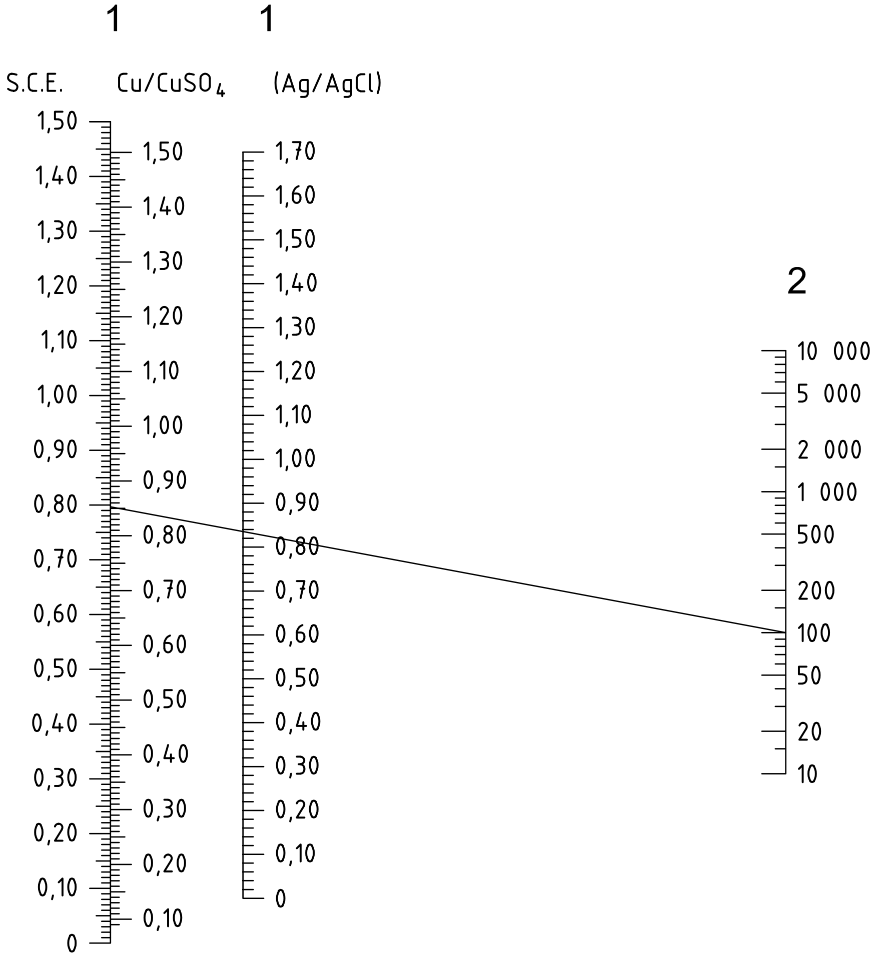
[e] Depending on the strength, specific metallurgical condition and stress level encountered in service, these alloys can be susceptible to hydrogen embrittlement and cracking. If a risk of hydrogen embrittlement exists, then potentials more negative than −0,8 V should be avoided. See also 7.2.3.

[f] This covers the possibility of SRB activity and/or high pipeline temperature ($T > 60$°C).

[g] If a metallurgical structure is not fully austenitic, these stainless steels can be susceptible to hydrogen-induced stress cracking (HISC) and high negative potentials should be avoided.

The potential of the Ag/AgCl/seawater reference electrode is dependent upon the concentration of chloride ions in the electrolyte, and hence the seawater resistivity. If the chloride concentration and hence the resistivity is known to differ significantly from that of ordinary seawater (typically 3,5 % and 30 Ω·cm respectively), the protection potential criteria shall be adjusted in accordance with Figure 1.

NOTE 2 The term “Ag/AgCl/seawater (undersaturated) reference electrode” can be used for this electrode.



Key

1 potential, in volts

2 resistivity, in Ω·cm

Figure 1 — Nomogram for the correction of potential readings made with the Ag/AgCl/seawater electrode in waters of varying resistivity against the SCE and $Cu/CuSO_4$ reference electrodes[17]

EXAMPLE If brackish water of 100 Ω·cm resistivity exists at the pipeline potential measurement site, the least negative potential for the effective corrosion-protection electrode will be −0,84 V and not −0,80 V as given in Table 1, with reference to the Ag/AgCl/seawater reference electrode.

Alternative reference electrodes for specific conditions are given in D.3.2.

7.2.2 HISC evaluation for martensitic and duplex stainless steel materials

HISC is a non-ductile mode of failure caused by an interaction between stresses, the cathodic protection system and a susceptible material. A special assessment shall be carried out to ensure that the risk of HISC is minimized. All load contributions causing stress and strain shall be included.

For duplex stainless steels, DNV-RP-F112[8] may be used to assess acceptable stresses and strains.

Fillet welds, doubler plates or aluminothermic welds should not be used directly on high-strength carbon steels (SMYS > 550 MPa), martensitic or duplex stainless steel materials. Installation of galvanic anode cables should be performed to special pipejoints consisting of internally clad carbon steel or other CRA materials which are not susceptible to HISC.

7.2.3 Thermally sprayed aluminium

If a component with thermally sprayed aluminium is cathodically protected at potentials more negative than −1,15 V, the thermally sprayed aluminium can suffer corrosion as a consequence of the build-up of alkali at the metal/electrolyte interface. A polarized potential more negative than −1,15 V should not be used unless previous test results or operating experience indicate that no significant corrosion will occur.

7.3 Design life

The design life of the pipeline CP system shall cover the period from initial installation to the end of pipeline operation as a minimum. However, the possibility of future life extension or future pipeline connections should be recognized at the design stage. Provisions should be made to accommodate possible future events and this can include revised coating breakdown criteria and/or incorporating facilities for future anode retrofits.

7.4 Design current densities for bare steel

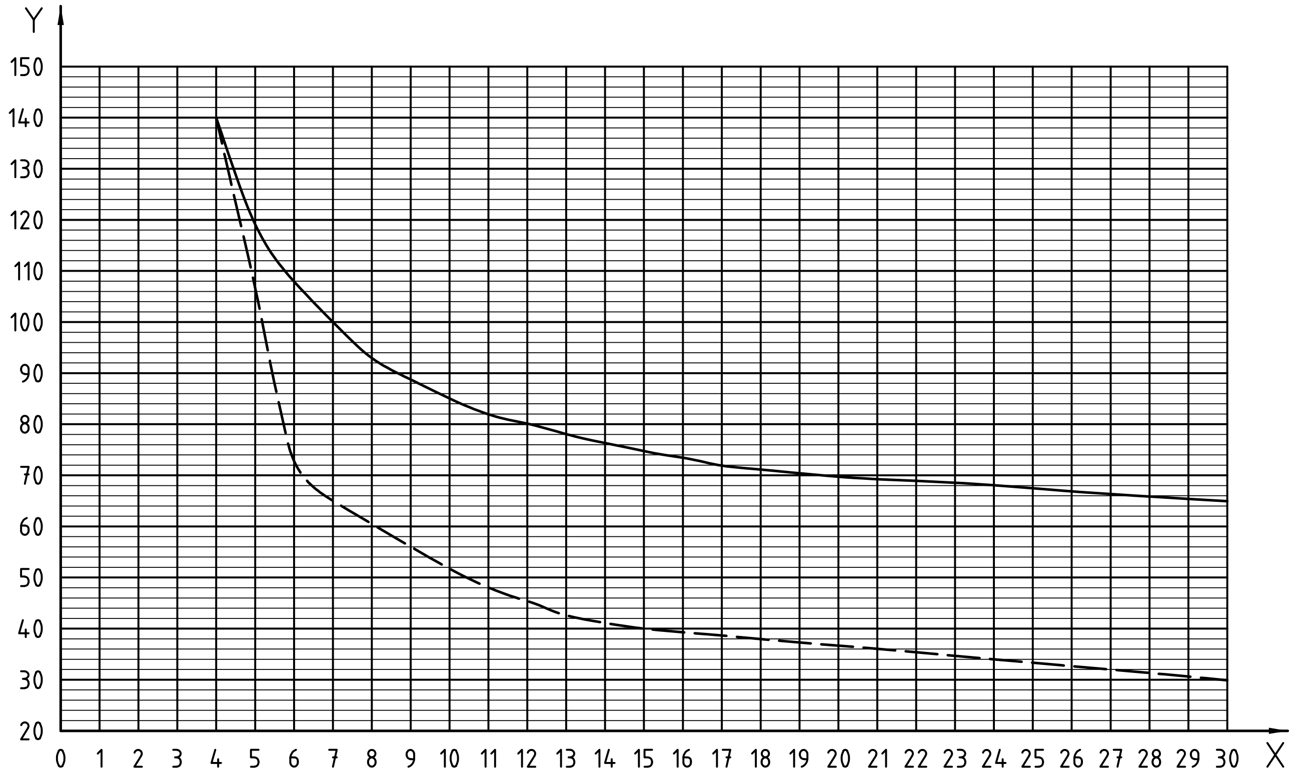
7.4.1 General

The design current densities depend upon the seawater temperature, the oxygen content, the seawater velocity and the ability to build up protective calcareous films on bare metal surfaces.

NOTE 1 In theory, three values of current density are significant: the initial, mean and final current densities, which refer to the current density required to polarize the pipeline within a reasonable period of time (i.e. 1 to 2 months, initial), the current density necessary to maintain the polarization (mean), and the current density necessary for an eventual repolarization which may occur close to the end of the pipeline life (final), e.g. after a heavy storm. For a coated pipeline, the initial current density is never the critical constraint in the design, so it is not considered further in Annex A. Pipelines are located on the seabed and depolarization in storms has not been found to have a significant effect, so the same current density value can be used for the mean and final current densities.

If it is decided for a specific location that a higher final current density needs to be considered in the design because of storms, a value which is 20 mA/m^2 above the mean value for that temperature may be used.

For most applications in water depth of less than 500 m, the design current densities are dependent only on the seawater temperature, and the current densities for non-buried pipelines should be assessed from Figure 2.



Key

X seawater temperature, °C

Y current density, mA/m2

Figure 2 — Mean current density range for non-buried bare steel pipelines

In Figure 2, the lower current–density curve may be used where there are no significant changes in oxygen content from surface to seabed, no build-up of protective calcareous films, and low to moderate seabed currents (up to 2 knots).

If no other data are known, the upper curve in Figure 2 should be used.

NOTE 2 Calcareous deposits, formed on the exposed surfaces of the pipeline by the application of CP current, reduce the current density required to maintain protective potentials and also improve current distribution. Pipeline coatings also favour the formation of a dense calcareous deposit, because the initial current density is rather high when defects are formed in the coating. However, the solubility of potential film-forming calcareous deposits is dependent on temperature, and colder waters might not allow the formation of protective calcareous deposits, or could require higher initial current density to achieve polarization.

NOTE 3 The lower curve was published in Reference [19]. This curve is based on test and field data from many platform and pipeline locations world-wide, collected over a number of years. The upper curve is a conservative curve fit of the data published in References [7] and [11] and, especially for deep waters, is generally accepted by operators and represents the highest current density values reported normally for seawater saturated with oxygen. The required current density values for a given field lie somewhere between these two extremes.

At temperatures below 6 °C, the mean design current density shall be 120 mA/m^2, unless otherwise specified, as limited data are available for temperatures below 6 °C.

If the seawater temperature profile along the pipeline route is not known, the required current density shall be based upon the minimum seabed temperature measured, which is usually the temperature at the deepest location along the pipeline route.

If the seawater temperature profile along the pipeline route is known, the curves in Figure 2 should be used with the averaged seawater temperatures to obtain current densities for each pipeline section. If the annual average seawater temperature varies by more than 5 °C over the pipeline length, the pipeline length should be split up into separate sections that cover intervals of no more than 5 °C each. The averaged seawater temperature should be used for each section.The design current densities discussed above are applicable for CP of bare carbon steel and stainless steel (austenitic, martensitic and duplex).

Current densities may alternatively be based on field measurements or data from facilities installed in the same general geographical location.

EXAMPLE There are specific locations where higher and lower current densities have been reported. These have been related to significant changes in oxygen content with depth, and/or significant seabed currents (see Table 2).

Table 2 — Examples of design current densities for specific locations

Location	**Water depth** m	**Seawater temperature** °C	**Mean current density** mA/M^2	**Comment**
US West Coast	> 500	10 to 12	90	moderate current flow
Cook Inlet	all depths	2	380	high seabed currents
Australia	> 500	12 to 18	90	large seasonal temperature variation
Norwegian Sea	> 1 000	−1 to 4	200	cold deep conditions
Offshore Brazil	> 300		130	temperature to be considered

7.4.2 Splash zone

For risers in the splash zone, current densities selected shall be 10 mA/m^2 higher than for the equivalent riser or pipeline below the splash zone (at the same temperature).

NOTE Splash zone depths vary by location; for example, in the North Sea, splash zones typically extend down to −10 m, whereas in the South China Sea, the splash zones typically extends down to −1 m.

7.4.3 Buried pipelines

For pipelines fully buried in sediments (trenched and naturally buried) or artificially covered (e.g. rock dumping), a design current density (mean and final) of 20 mA/m^2 should be used, irrespective of seawater temperature, oxygen content or depth.

7.4.4 Elevated temperatures

Pipelines operating with temperatures in excess of 25 °C on the outside metallic surface of the pipe require an adjustment to the design current density. The design current densities shall be increased by 1 mA/m^2 for each degree Celsius of the metal/environment above 25 °C up to 100 °C.

NOTE Increasing water temperature decreases oxygen solubility. Increasing temperatures also accelerate the corrosion rate.

7.4.5 Current drains

If subsea facilities are connected to the pipeline CP system, the current drain to subsea structures, wellheads, manifolds and well casing shall be included in the design. An allowance should be included in the total design current requirements to compensate for the current load imposed by the well casings below the mudline. The design current for wells should be 5 A per well.

7.5 Coating breakdown factors

The current demand of a coated pipeline increases with time as the coating deteriorates. Enough cathodic protection capacity should be provided to maintain protection as the coating deteriorates.

These coating breakdown factors shall be applied to calculate the bare metal surface areas of the coated pipe for mean conditions and at the end of the design life respectively (see Annex A). Mean and final coating breakdown factors shall be calculated as follows.

The mean coating breakdown factor, $\overline{f}_c$, is given by Equation (1):

$$\overline{f}_c = f_i + (0{,}5\Delta f \times t_{dl}) \tag{1}$$

The final coating breakdown factor, f_f, is given by Equation (2):

$$f_f = f_i + (\Delta f \times t_{dl}) \tag{2}$$

where

f_i is the initial coating breakdown factor at the start of pipeline operation;

Δf is the average yearly increase in the coating breakdown factor;

t_{dl} is the design life, expressed in years.

The coating breakdown factors given in Tables 3 and 4 should be considered. Coating breakdown factors for pipeline coatings not included in Tables 3 and 4 shall be fully documented.

NOTE 1 Typical parameters f_i and Δf are given in Table 3 (for pipelines without concrete weight coating) and Table 4 (for pipelines with concrete weight coating) which address combinations of the most common coating systems used for corrosion prevention or thermal insulation. The coating breakdown factors given refer to both seawater exposed pipelines and pipelines buried in the seabed.

NOTE 2 The coating breakdown factors are based on coating quality being in accordance with the various parts of ISO 21809[4] or with other commonly applied industry standards specifying an equal level of quality coatings. The coating breakdown factors include some allowance for damage to pipeline coatings during fabrication, handling, transportation, installation or operation such as third-party damage (e.g. anchors, trawl gear). However, they do not include allowance for extreme damage or for field joints intentionally left uncoated.

If extreme damage or uncoated field joints are anticipated, the affected surface area shall be estimated and included in design calculations as bare metal surface (f_c = 1), or increase the coating breakdown factors in Tables 3 and 4.

Table 3 — Coating breakdown factors, f_c, for pipelines without concrete weight coating

Factory-applied coating type	Field joint coating type	f_i	Δf
Fusion-bonded epoxy (FBE)	Heat-shrinkable sleeves (HSS[a])	0,080	0,003 5
	FBE	0,060	0,003 0
Three-layer coating systems including epoxy, adhesive and polyethylene (3LPE)	HSS[a]	0,009	0,000 6
	FBE	0,008	0,005
	Multilayer coating including epoxy and PE (e.g. moulded, HSS[a] or flame spray)	0,007	0,000 5
Three-layer coating systems including epoxy, adhesive and polypropylene (3LPP)	HSS[a]	0,007	0,000 3
	FBE	0,006	0,000 2
	Multilayer coating including epoxy and PP (e.g. HSS[a], hot tapes, moulding or flame spray)	0,005	0,000 2
Heat insulation multilayer coating systems including epoxy, adhesive and/or PE, PP or PU	Thick multilayer coating systems including epoxy, adhesive and/or PE, PP, PU, HSS[a] or a combination of these products.	0,002	0,000 1
Thick coatings: elastomeric materials (e.g. polychloroprene or EPDM) or glassfibre-reinforced resins	Thick elastomeric materials or glassfibre-reinforced resins	0,002	0,000 1
Flexible pipelines	Not applicable (mechanical couplings)	0,002	0,000 1

[a] HSS can be used with or without primer.

Table 4 — Coating breakdown factors, f_c, for pipelines with concrete weight coating

Factory-applied coating type	Field joint infill	Field joint coating type	f_i	Δf
Asphalt or coal tar enamel	no	Cold-applied tapes (CAT[a]) or heat-shrinkable sleeves (HSS) over a wire-brushed surface to St 3	0,045	0,002 5
		Cold-applied tapes (CAT[a]) or heat-shrinkable sleeves (HSS) over a blast-cleaned surface to Sa 2 ½	0,040	0,002 0
	yes	CAT[a]	0,030	0,001 5
		HSS	0,020	0,000 8
Fusion bonded epoxy (FBE)	no	HSS	0,045	0,002 5
		FBE	0,035	0,002 0
	yes	HSS	0,040	0,002 0
		FBE	0,030	0,001 5
Three-layer coating systems including epoxy, adhesive and polyethylene (3LPE)	no	HSS or FBE,	0,008	0,005
		Multilayer coating including epoxy and PE (e.g. HSS, or flame spray)	0,007	0,000 3
	yes	HSS or FBE	0,004	0,000 2
		Multilayer coating including epoxy and PE (e.g. HSS or flame spray)	0,004	0,000 2
Three-layer coating systems including epoxy, adhesive and polypropylene (3LPP)	no	HSS or FBE	0,008	0,000 5
		Multilayer coating including epoxy and PP (e.g. HSS, moulded or flame spray)	0,007	0,000 3
	yes	HSS or FBE	0,004	0,000 2
		Multilayer coating including epoxy and PP (e.g. HSS, moulded or flame spray)	0,004	0,000 2

[a] CAT should be applied with primer.

For heat insulation covered with concrete coating, the values for heat insulation in Table 3 should be used.

8 Galvanic anodes

8.1 Design of system

The galvanic anode system shall be designed by locating properly shaped and sized anodes along the pipeline such that sufficient current is delivered to the pipeline to maintain the required potentials throughout the design life.

NOTE 1 Normally, the CP system consists of bracelet anodes distributed at regular intervals along the pipeline.

Design calculations for the CP systems shall demonstrate that the anodes give the pipeline the necessary current to meet the current density requirements. The anodes shall deliver sufficient current to meet the mean and final design current demands.

NOTE 2 The weight and shape of individual anodes can be limited by anode manufacturing and handling constraints.

If anode sleds are used, alternative methods for distribution and connection to the pipeline should be considered.

The spacing between anodes shall be determined together with the number of anodes. The anode spacing shall be close enough to maintain an adequate protection in the event of mechanical or electrical loss of a single anode. When accepted by the pipeline operator, anode spacing exceeding 300 m shall be justified by attenuation calculations in accordance with Annex B or other mathematical modelling accepted by the pipeline operator.

For short pipelines, anodes may be installed at each end of the pipeline if it can be demonstrated by mathematical calculations or modelling that CP can be achieved. Typically, this type of installation is used on inter-platform pipelines. Anodes for the pipeline can be attached to the platform if the pipeline is electrically connected to the platform. Attenuation calculations shall be carried out in accordance with Annex B for these installations to determine whether it is feasible to protect the mid-point of the pipeline using anodes located at the ends.

Extra anodes should be placed on the portion of the pipeline that is near a structure, platform or shore approach. A factor of 2 should be included in the calculated design current demand for the first 1 000 m.

NOTE 3 The reasons for adding extra anodes include:

- increased risk of pipeline coating damage due to dropped objects and vessel anchors;
- possibility of an increased current drain;
- likelihood that the pipeline potential is more negative than that on the platform, so that the pipeline anodes near the structure will also provide current to the platform.

All these factors increase current output from the anodes and reduce anode life.

Anodes and anode supports shall be designed to avoid any sharp edges or corners or protruding assemblies which may be hazardous to personnel (see also Annex F). This latter requirement particularly applies to diving operations conducted near anode installations.

NOTE 4 Further information on galvanic anodes is given in EN 12496[9].

8.2 Selection of anode material

The alloy selected shall be one that has given a satisfactory performance under similar field conditions, or in laboratory and field trials in a simulated environment.

Unless otherwise documented, aluminium anodes should not be used below 0,5 % salinity.

Zinc anodes should not be used at temperatures exceeding 50 °C unless their performance is supported by appropriate test data to the contrary.

Intergranular corrosion and/or a reduction in electrochemical capacity are the main problems for zinc anodes at elevated temperatures. The galvanic anode alloys developed for marine applications have been specifically conceived to perform in seawater with an alkaline pH, high salinity and a significant content of oxygen. For some areas, the seawater and mud conditions can be very different, such as being totally anaerobic with large concentrations of SRBs and sulphides. In addition, the salinities can be low. This may be of importance for anode selection. Long-term testing in accordance with Annex C should be carried out for applications in such environments.

NOTE 1 Aluminium and zinc alloys are the materials most often used as galvanic anodes on pipelines. Typical compositions are respectively given in 9.4 and 9.5.

NOTE 2 Aluminium alloy anodes have decreased electrochemical efficiency at elevated temperatures. Certain aluminium alloy compositions can be unsuitable at elevated temperatures.

NOTE 3 The behaviour of certain aluminium alloys can be adversely affected by burial in seabed mud, particularly if the current output remains low.

NOTE 4 Aluminium alloys containing magnesium can suffer ageing with a loss of mechanical properties.

8.3 Electrochemical properties

For design purposes, the values quoted in Table 5 should be used. Alternative values for the electrochemical capacities of galvanic anodes may be used if the data are properly documented by testing as detailed in Annex C. The electrochemical properties shall be documented for the relevant anode operating temperatures.

Table 5 — Design values for galvanic anodes

Anode type	Anode surface temperature[a]	Immersed in seawater		Buried in seawater sediments[d]	
		Potential	Electrochemical capacity	Potential	Electrochemical capacity
		Ag/AgCl/ seawater	ε	Ag/AgCl/ seawater	ε
	°C	mV	A·h/kg	mV	A·h/kg
Aluminium	< 30	– 1 050	2 000	– 1 000	1 500
	60	– 1 050	1 500	– 1 000	800
	80[b]	– 1 000	900	– 1 000	400
Zinc	< 30	– 1 030	780	– 980	750
	> 30 to 50[c]			– 980	580

Electrochemical capacity for a given alloy is a function of temperature and anode current density. Reference is made to Annex A for guidance on CP design for variations in anode current densities.

For non-buried pipelines, the anode surface temperature should be taken as the external pipeline temperature and not the internal fluid temperature. For buried pipelines, the anode surface temperature shall be taken as the internal fluid temperature.

[a] For anode surface temperatures between the limits stated, the electrochemical capacity shall be interpolated.

[b] For aluminium anodes, the anode surface temperature shall not exceed 80 °C unless the performance has been demonstrated in tests and has been documented.

[c] For zinc anodes, the anode surface temperature shall not exceed 50 °C unless satisfactory performance has been demonstrated in tests and has been documented.

[d] Pipelines which are rock-dumped shall be considered as buried in seawater sediments.

The design values in Table 5 are applicable to seawater with a typical salinity of 3,5 %. For salinities below 1,2 %, the design values given for anodes buried in sediments should be used.

NOTE 1 The electrochemical capacity can be lower for aluminium in brackish water than in ocean seawater.

For pipelines where the burial condition is unknown or the pipeline is expected to be marginally covered with loose sediments, the cathodic protection design should be made on the basis of

a) buried anodes, which will give the lowest anode capacity (due to high surface temperature), and

b) pipeline exposed to seawater, which will give the highest current requirement.

NOTE 2 Anode compositions which have been qualified for one set of operating conditions, e.g. low temperature, unburied, might not be suitable for use under other conditions, e.g. high temperature, buried.

8.4 Anode shape and utilization factor

Anodes shall be designed (see 8.5) in such a way that a utilization factor, μ, is assured. Unless otherwise specified, a utilization factor of 0,80 should be used for bracelet anodes and a minimum of 0,90 for slender anode systems.

The distribution of the anode insert within the body of the anode material should be considered to ensure that the specified utilization factors are achieved.

For bracelet anodes with a thickness of less than 50 mm, utilization factors of less than 0,80 may be used depending on the details and tolerances of the anode insert. Reduced anode surface area and possible insert exposure shall be considered.

8.5 Mechanical and electrical considerations

The internal diameter of a bracelet anode should be determined by the diameter of the pipe and the thickness of coatings applied. Tolerances of the outer diameter of pipe and coating thickness shall be taken into account.

Depending on the pipeline installation method, the anodes can be susceptible to damage. This concern is critical when the anodes pass over a stinger as the pipeline leaves the lay barge.

For non-weight-coated pipelines, anodes with either tapered shoulders or taper cones should be used to reduce the risk of the anodes catching on the stinger rollers.

For weight-coated pipelines, the thickness of anodes should match the thickness of the weight coating, such that the anodes will roll smoothly over the stinger rollers.

NOTE A variety of galvanic anode designs are available for attachment to the pipeline. Semi-cylindrical bracelets with tapered and square shoulders are available for use on small- and medium-diameter pipelines. For larger-diameter pipelines where semi-cylindrical anodes would be impractical, segmented designs are available. For special circumstances, anodes can sometimes be cast directly onto the pipe.

The core shall be designed to maintain electrical integrity with the anode body for the full design life of the anode.

The electrical connection between the pipeline and the anode is generally made by a bonding wire or direct welding of the anode core to the pipeline. The bonding wire can be attached by a variety of methods, including aluminothermic welding and pin brazing. The attachment method shall be compatible with the requirements of the pipe lay method and the metallurgy of the pipeline steel (see 7.2.2).

Anode core extensions of bracelet half-shells are generally oriented in the longitudinal direction of the half-shell and at the mid-point of the half-shell cross-section. Anode core extensions, usually a flat steel bar, should be fully welded to the core and the dimensions should be compatible with the pipe dimensions and material.

9 Galvanic anode manufacturing

9.1 Pre-production test

The detailed anode design shall include anode drawings showing shape and dimensions with tolerances. Prior to fabrication of the anodes, a pre-production test shall be carried out at the foundry to ascertain that all moulds, cores, casting equipment and other components are in accordance with applicable standards, governing drawings, dimensions, tolerances, inspection procedures and data sheets.

At least one of the anode cast assemblies should be inspected destructively in accordance with 10.9.

Other types of procedure qualification may be considered.

9.2 Coating

Bracelet anodes should be coated on the sides facing the pipeline and the concrete weight coating. The coating applied to the anode faces should be an immersion-grade two-component epoxy with a minimum thickness of 100 µm. Coating sides of other anode types should also be considered.

The exposed (external) surface of the anode shall be free from coating.

9.3 Anode core materials

Anode cores shall be fabricated from weldable structural steel plate/sections according to a recognized standard such as EN 10025 or similar. Anode core materials to be welded to the pipeline shall be compatible with the pipeline material or structural elements to which it is attached, and the carbon equivalent (CE) shall not exceed the CE value of the pipeline material. The CE value shall be calculated using Equation (3).

$$CE = C + Mn/6 + (Cr + Mo + V)/5 + (Ni + Cu)/15 \tag{3}$$

where the symbols of the elements represent the mass fraction of the corresponding element.

NOTE The formatting for Equation (3) does not conform to the standard ISO formatting but it has been accepted, exceptionally, on the basis of its long-standing and well established history in the industry.

If the full chemical composition is not reported, the alternative CE value of Equation (4) may be used.

$$CE = C + Mn/6 + 0{,}04 \tag{4}$$

The material certificate for the anode cores shall meet the requirements of EN 10204:2004, 2.1 b).

All fabrication welding of steel anode cores shall be in accordance with the relevant requirements of AWS D1.1/D1.1M or an equivalent standard, and performed by welders qualified according to ISO 9606-1 or AWS D1.1/D1.1M. Qualification of welding procedures shall be in accordance with the requirements of ISO 15607, AWS D1.1/D1.1M, or equivalent.

Anode core steel for aluminium anodes shall be blast-cleaned to Sa 2½ in accordance with ISO 8501-1 prior to casting and maintained until casting commences.

Anode core steel for zinc anodes shall be blast-cleaned to the minimum standard Sa 2½ in accordance with ISO 8501-1 or galvanized according to ISO 1461 or equivalent. Rust discoloration and/or visual surface contamination of zinc-coated surfaces shall not be permitted. The degree of cleanliness shall be maintained until casting.

9.4 Aluminium anode materials

The aluminium anode material should be of the Al-Zn-In type. The chemical composition of the anodes shall be formulated to meet the potential and electrochemical capacity requirements of the project design. A typical chemical composition known to perform well in many conditions is given in Table 6. This composition is in accordance with EN 12496. Other compositions may be used if testing demonstrates that they meet the required anode electrochemical properties. Caution should be exercised if any element falls outside the specified range, since the anode electrochemical properties may be less than the design requires.

Table 6 — Typical chemical composition of aluminium anode materials

Element[a]	Mass fraction w	
	min. %	max. %
Zn	2,5	5,75
In	0,016	0,040
Fe	—	0,09
Si	—	0,12
Cu	—	0,003
Cd	—	0,002
Other	—	0,02 (each)
Al	Remainder	

[a] Under certain operating conditions such as deep (>500 m) or cold water, it can be necessary to select a narrower anode composition range than given in this table in order to obtain the required anode electrochemical properties.

9.5 Zinc anode materials

A typical chemical composition known to perform well in many conditions is given in Table 7.

Table 7 — Typical chemical composition of zinc anode materials

Element	Mass fraction w	
	min. %	max. %
Cu	—	0,005
Al	0,10	0,50
Fe	—	0,005
Cd	0,025	0,07
Pb	—	0,006
Zn	Remainder	

Other compositions may be used if testing demonstrates that they meet the required anode electrochemical properties. EN 12496 gives alternative compositions for zinc anodes. Caution should be exercised when any element falls outside the specified range, as anode performance may be less than the design requires.

10 Galvanic anode quality control

10.1 General

A quality control procedure shall be followed to ensure that the requirements in this clause are met.

10.2 Steel anode cores

All welds shall be visually inspected.

Required surface finish shall be verified by visual inspection immediately prior to casting.

10.3 Chemical analysis of anode alloy

Two samples from each heat shall be taken for chemical analysis. The samples shall be taken in the beginning and at the end of casting from the pouring stream. For smaller alloying furnaces (max. 500 kg), it is acceptable to take one sample per heat. The sample shall be taken at the beginning of the first heat and at the end of the second heat, then in the beginning of the third heat and so on. The samples shall be analysed to verify the required chemical composition.

Anodes from heats whose chemical composition do not meet the required chemical composition shall be rejected.

10.4 Anode mass

Individual anode castings of each type shall have a net mass within ±3 % of the nominal net mass for anode castings with total mass above 50 kg. For anode castings below 50 kg, the mass tolerances shall be ±5 % unless otherwise agreed between the end user and the relevant parties.

At least 10 % of the total number of anode castings shall be weighed to confirm compliance with this requirement. If agreed between the end user and the relevant parties, the weighing can be done in groups, which gives an average individual weight.

The total net mass of anodes shall not be less than the nominal value. A maximum value can be agreed between between the end user and the relevant parties.

10.5 Anode dimensions and straightness

10.5.1 Slender anodes

The anode dimensions and straightness for slender anodes shall conform to the following:

- anode length shall be within ±3 % of the nominal length or ±25 mm, whichever is smaller;
- anode mean width shall be within ±5 % of the nominal mean width;
- anode depth shall be within ±10 % of the nominal mean depth;
- the diameter of cylindrical anodes shall be within ±5 % of the nominal diameter;
- the straightness of the anode shall not deviate by more than 2 % of the anode nominal length from the longitudinal axis of the anode.

At least 10 % of the total number of anodes shall be checked to confirm compliance with these requirements.

10.5.2 Bracelet anodes

Each bracelet anode length shall be within ±3 % of the nominal length or ±25 mm, whichever is smaller.

The anode internal diameter shall conform to the following dimensional tolerances:

0 / +4 mm for pipeline diameters	≤ 300 mm
0 / +6 mm for pipeline diameters	> 300 mm and ≤ 610 mm
0 / +1% for pipeline diameters	> 610 mm

The dimensional tolerance on the anode thickness shall be ±3 mm.

At least 10 % of the total number of anodes shall be checked to confirm compliance with these requirements.

Anodes shall be free from excessive bowing or twisting. The anode casting shall not deviate by more than 2 % of the anode nominal axial length from the longitudinal axis of the anode. At least one completely assembled bracelet anode shall be fitted. This shall be verified by fitting an agreed number of bracelet assemblies to a full-length former or by an equivalent method. The external diameter shall not exceed the summation of tolerances given above.

10.6 Anode core dimensions and position

Tolerances on the anode core position within the anode shall be subject to agreement prior to fabrication, to comply with utilization factor requirements, and should be part of the fabrication quality plan. Anode core protrusions and any other critical dimensions shall be measured and shall conform to specified requirements.

10.7 Anode surface irregularities

10.7.1 Slender anodes

Slender anodes shall be inspected visually to confirm compliance with the following requirements:

- shrinkage depressions shall not exceed 10 % of the nominal depth of the anode material to the anode core, as measured from the plane of the anode surface to the bottom of the depression;
- in the topping-up area, the maximum shrinkage shall not be more than a 10 mm depth measured from a straight edge across the topping-up face and not more than 0,5 % of the gross anode volume; any additional topping-up materials or casting surface irregularities shall be fully bonded to the bulk anode material;
- cold shuts shall not exceed a depth of 10 mm and/or extend over a total length of more than three times the width of the anode;
- all protrusions that are hazardous to personnel during handling shall be removed.

10.7.2 Bracelet anodes

Bracelet anodes shall be inspected visually to confirm compliance with the following requirements:

- shrinkage depressions shall be < 10 % of the thickness of the anode as measured from the uppermost corner to the bottom of the depression. Shrinkage depressions that expose the anode core are not acceptable;
- in the topping-up area, the maximum shrinkage shall not be more than 10 mm measured from a straight edge across the topping-up face and not more than 0,5 % of the gross anode volume. Any additional topping-up materials or casting surface irregularities shall be fully bonded to the anode material;
- any cold shuts shall be < 10 mm depth and/or extend over a total length of < 150 mm;
- all protrusions that are hazardous to personnel during handling of the anode(s) shall be removed.

10.8 Cracks

10.8.1 General

All anodes shall be inspected for cracks.

NOTE Cracks can occur while cooling during the casting of galvanic anode bracelets because of the different coefficients of expansion of the anode and the core. These cracks are not detrimental, provided they do not converge in a manner that allows loss of anode material.

No treatment shall be applied to grind, peen, or in any other manner dress cracks before inspection and checks.

Zinc anodes shall be free from visible cracking without the aid of magnification.

Cracks may be accepted in aluminium anodes provided the cracks will not cause any mechanical failure during installation, transportation or service of the anode. The combination of cracks and lack of bond to the anode core and cracks in the area where the anodes are not fully supported by the anode core shall not be accepted. For aluminium, the cracking criteria given in 10.8.2 and 10.8.3 shall apply.

10.8.2 Aluminium slender anodes

The following cracking criteria apply:

- for sections of anode material not fully supported by the anode core, no visible cracks shall be permitted without magnification;
- cracks within the section of an anode supported by the anode core are not acceptable if the length is > 100 mm and/or the width > 1 mm;
- cracks penetrating to the steel anode cores or through the anode are not permitted;
- a maximum of 10 cracks per anode with small dense cracks counting as one and cracks < 0,5 mm wide not counted.

Longitudinal cracks are not permitted.

10.8.3 Aluminium bracelet anodes

The following cracking criteria apply:

- for sections of anode material not fully supported by the anode core, no visible cracks shall be permitted without magnification;
- cracks penetrating to the steel anode cores or through the anode are not permitted;
- cracks with a length of > 100 mm or > 50 % of the anode diameter (whichever is greater) and/or width > 3 mm are not acceptable.

Provided the above is satisfied, the following cracks are acceptable in transverse direction:

- cracks with a length of ≤ 50 mm or ≤ 20 % of the anode diameter, whichever is less, and a width < 3 mm;
- cracks with a length of 50 mm to 200 mm or between 20 % and 50 % of the anode diameter, whichever is less, and a width < 1 mm;
- cracks with a length of 50 mm to 200 mm are limited to two per half-bracelet or four per anode.

Cracks in the longitudinal direction shall be < 100 mm in length or < 20 % of anode length, whichever is less, and/or ≤ 1 mm in width.

10.9 Internal defects, destructive testing

The number and method of selection of anodes to be destructively tested (sectioned) within each anode type/size shall take into account anode design, the total number of anodes, and the pre-production test requirements (9.1).

If an anode does not meet the requirements below, an additional anode shall be subjected to destructive testing. If this does not satisfy the specified requirements, the whole anode lot should be rejected or other actions taken as agreed prior to fabrication.

Slender anodes should be sectioned transversely at 25 %, 33 % and 50 % of the nominal length, or at other agreed locations for a particular anode design. The cut faces, when examined visually without magnification, shall conform to the following criteria:

- Gas holes and porosities shall be limited to maximum 2 % of the total cut surface area, and maximum 5 % of any individual cut surface area. No cavity shall exceed 1 cm^2.
- Non-metallic inclusions shall be limited to maximum 1 % of the total cut surface area and maximum 2 % of any individual cut surface area. No non-metallic surface shall exceed 1 cm^2.
- Lack of bond (voids) shall be limited to maximum 10 % of the total tubular anode core circumference and maximum 20 % of the circumference for any individual cut.

Bracelet anodes should be sectioned transversely by cuts at 25 % and 50 % of the nominal length, or at other agreed locations for a particular anode design. The cut faces, when examined visually without magnification, shall conform to the following criteria:

- Gas holes and porosities shall be limited to maximum 2 % of the total cut surface area, and maximum 5 % of any individual cut surface area. No cavity shall exceed 1 cm^2.
- Non-metallic inclusions shall be limited to maximum 1 % of the total cut surface area and maximum 2 % of any individual cut surface area. No non-metallic surface shall exceed 1 cm^2.
- Lack of bond (voids) adjacent to the anode core shall be limited to maximum 10 % of the total anode core perimeter and maximum 20 % of any individual cut.

The conformance of the anode core position within the anode body in accordance with the design drawings shall be confirmed by physical measurement on the cut faces.

Other types of procedure qualification may be considered based on agreement between the end user and the relevant parties.

10.10 Electrochemical quality control testing

The following shall be assessed:

- closed-circuit potential;
- electrochemical capacity;
- corrosion pattern (uneven consumption, intergranular attack, passivity, etc.).

One set of tests shall be carried out for each 15 t of anodes produced. The electrochemical test data shall be reported.

Testing should be carried out in natural seawater or in artificial seawater in accordance with ASTM D1141.

The test should be conducted using the procedure described either in Annex E or in NACE TM0190[12]. For testing in accordance with Annex E, test results shall meet the acceptance criteria in Table 8. For other testing procedures, acceptance criteria shall be documented in the test procedure.

Table 8 — Recommended acceptance criteria for electrochemical performance (production quality testing) using Annex E

Anode type	**Minimum electrochemical capacity** A·h/kg	**Closed-circuit potential** mV (Ag/AgCl seawater)
Aluminium	2 500	− 1 050
Zinc	780	− 1 030

If the specified requirements are not met, re-tests should be carried out on three specimens from each heat that failed to meet the requirements. Failure of any of these three specimens to meet the specified requirements should lead to rejection or other actions taken as agreed prior to fabrication of all anodes from the heat(s) involved.

The tested anode sample surface shall not show any signs of passivity or intergranular attack.

11 Galvanic anode installation

Welders and welding procedures should be qualified for any applicable welding process to a recognized standard such as AWS D1.1/D1.1M.

Bracelet anodes shall be bolted on, or welded to, the pipeline.

For bracelet anodes mounted on pipe joints that are concrete-weight-coated, electrical contact between the concrete reinforcement and the anodes shall be avoided by providing a gap, typically of 25 mm, at each end of the anode. Gaps between bracelet anode half-shells and between half-shells and the concrete shall be filled with non-conductive mastic or similar compound.

Anode installation shall be carried out in such a way that damage to the pipeline coating is minimized.

The connections of cables to the pipeline shall be designed to ensure adequate mechanical strength and electrical continuity and to prevent damage to the pipe at the point of connection. The removal of the protective coating from the pipe should be kept to a minimum. After installation of the cable-to-pipe connection, the coating shall be repaired using a compatible coating material.

A detailed cable-to-pipeline connection procedure shall be included in the CP design. Welding of cable connections shall not be carried out on bends or within 200 mm from pipeline welds.

For aluminothermic welding of cables, the welding procedure shall be such that copper penetration into the pipeline material shall be less than 1 mm and local pipeline hardness shall remain within the requirements given in the pipeline specification.

Aluminothermic weld charges should not be greater than 15 g. If cables larger than 16 mm^2 need to be attached, the cores shall be separated into a number of smaller strands, each measuring less than 16 mm^2 and welded separately.

Aluminothermic welding should not be carried out on corrosion-resistant alloy pipelines. Alternative methods such as pin brazing, soft soldering, adhesive bonding or friction welding may be used, provided that the detailed procedure and performance are reliable and properly documented.

All items to be protected by CP shall be electrically connected and should have a welded or brazed connection to an anode. All bolted or clamped components with a surface area exceeding 1 m^2 shall have an all-welded or brazed connection to an anode. For all bolted or clamped assemblies without an all-welded or brazed electrical connection, it shall be verified that the electric resistance is less than 0,1 Ω. The pipeline coating on contact surfaces shall be removed prior to making the connection.

Cables should be copper-cored, and shall be insulated and sheathed to withstand the prevailing chemical and mechanical conditions. The minimum conductor size for measurement cables shall be 4 mm^2. Cables shall be sized such that no excessive voltage drops occur which reduce the capacity of the system.

If the contact is made by using current-carrying copper cables welded or brazed at each end, these shall be stranded and have a minimum cross-section of 16 mm^2 and brazed to the cable shoe. At least two cables per anode shall be installed. For half-shell anodes, two half-shells shall be considered as a single anode.

When electrical continuity is to be achieved by direct welding of core extensions, a doubler pad should be pre-installed on the pipeline to avoid detrimental effects of the fillet welds and the external coating.

For pipelines coated with thick insulating coating systems, the anodes may be placed on the outside of the coating and electrical connection may be made to a steel bracket with a doubler pad arranged to provide a surface for the attachment which is flush with the outer diameter of the insulating coating.

After the attachment process, the area shall be coated with a compatible coating system.

Only in exceptional cases (e.g. the retrofit of a CP system or the use of remote anode assemblies) should the underwater installation of anodes, utilizing either bolted or clamped devices or welding, be carried out.

Bolted connections with set screws or friction welding may be considered for the electrical connection of anode retrofit systems.

12 Impressed-current CP systems

12.1 Current sources and control

NOTE Impressed-current systems utilize a transformer-rectifier as the current source. Statutory requirements can apply for its design, installation and operation.

Separate negative connections shall be installed for each pipeline to be protected, independent of any negative connection to the platform or any land-based installation. Negative connections shall be terminated in a control box. There shall be a facility to regulate and measure the protective current to each pipeline.

The control of the transformer-rectifier current output may be manual or automatic. In the first case, either current or voltage control may be used, while automatic control shall be based on potential readings from fixed reference electrodes. Alarm functions indicating excessive voltage/current load on anodes and/or too negative or too positive protection potentials should be included.

The current output from individual anodes should each be independently adjustable.

12.2 Impressed-current anode materials

Anode material should be mixed metal oxides or platinum on a substrate of titanium, niobium or tantalum, graphite, high-silicon cast iron, magnetite, precious metals or steel. Other impressed-current materials can be used in specific applications if they are reliable and properly documented. For land-based CP systems which are designed to protect offshore pipelines, alternative anode materials may be used if they are reliable and properly documented in accordance with ISO 15589-1.

NOTE The anode material and substrate determine the maximum operating voltage and anodic current density that can be utilized. Impressed-current materials suffer deterioration, the magnitude of which is dependent on the anodic current density and the applied voltage.

12.3 System design

WARNING — During operation of CP systems, chlorine gas can develop at anode surfaces and hydrogen gas can develop at cathode surfaces. To avoid any health and safety hazards, design and operation shall avoid any detrimental build-up of the gases.

Impressed-current anodes are located at the ends of submerged pipelines. The current output shall be sufficient to protect the pipeline to the mid-point. Impressed-current systems should be designed for larger current outputs than galvanic anodes and achieve a reduced current-distribution efficiency.

The high current output can result in overprotection of the pipeline nearest the impressed-current anodes. Current attenuation calculations should therefore be conducted to verify that mid-point protection can be achieved without overprotecting the ends (see Annex B)

The total electrochemical capacity of the impressed-current CP shall be at least 1,25 times the total demand of the pipeline calculated as described in Annex A.

To account for both uneven current distribution and a higher risk of anode malfunction compared to galvanic anode systems, the design of the impressed-current CP system shall include redundancy with respect to the number of anodes.

Impressed-current anodes and cables shall be designed to withstand all expected forces during installation and operation. Anodes shall be designed so that they can be replaced either from the surface or subsea by diver or ROV.

Where anodes are mounted within 1,5 m of the support structure, a non-conductive coating or sheet (minimum 1 mm thickness), i.e. a dielectric shield, shall be applied to the adjacent support surface.

NOTE 1 This precaution is to prevent excessively negative potentials. Typically, shields of prefabricated glass-fibre-reinforced sheets of epoxy resin are used, and may be an integral part of the anode assembly or fastened to the object with an epoxy resin. Alternatively, liquid-applied coatings such as glass-flake-reinforced epoxy or polyester can be applied.

Anode cables shall have a steel armour or shall be adequately protected by routing within a dedicated conduit. Provisions for repairs to and replacement of cables shall be incorporated in the design.

NOTE 2 Restrictions for routing of cables in hazardous areas can apply.

Platinum- or gold-coated titanium, niobium, and tantalum should be used for electrical contacts exposed to seawater.

Pipelines protected by impressed current shall be electrically isolated at both ends from adjacent structures/pipelines. Isolating joints should be located above water at a location suitable for inspection and maintenance. If interference effects from adjacent structures or pipelines are to be considered, connections for the installation of resistive bonds should be installed.

If impressed-current systems are used, fixed reference electrodes shall be installed to verify adequate CP of the pipeline and shall include potential monitoring in the area closest to the anode, i.e. to verify there is no overprotection. Critical areas where diver or ROV inspection is prevented shall have fixed reference electrodes.

Since fixed reference electrodes have a limited life, procedures for maintenance and on-line calibration should be established.

Positive and negative cables shall not be placed in a common conduit.

To evaluate the performance of the CP on offshore pipelines protected by an impressed-current system, measuring cables and test points shall be installed at each end of the pipeline if direct contact is not possible.

At isolating joints, two cables shall be connected to each side of the joint or flange. The cables shall be separately terminated in one test post or junction box with suitable facilities to install direct or resistive bonds. To enable reproducible monitoring, the test box should be installed in a convenient, safe location close to the riser, where there is vertical access to the seawater for riser-drop cell surveys.

12.4 Manufacturing and installation considerations

Manufacturing of impressed-current anodes, subsea electrical connectors and dielectric shields shall be performed according to an approved quality control system. Any welding or brazing of cables shall be carried out according to a recognized procedure.

12.5 Mechanical and electrical considerations

The electrical connection between the anode lead cable and the anode body shall be made watertight and mechanically sound.

Cable and connection insulating materials shall be resistant to chlorine, hydrocarbons and other deleterious chemicals.

Care shall be taken to provide suitable mechanical protection for both the anode and its connecting cable. On suspended systems, the individual anodes or anode strings should be equipped with winches or other retrieval means as a damage-preventing measure during severe storms or for routine inspection and maintenance, and the implications of a loss of protection during these periods should be assessed.

NOTE 1 Impressed-current systems are more critical with respect to mechanical damage than galvanic anode CP systems because relatively few anodes are involved, each of which discharges a substantial amount of protective current. The loss of an anode or any negative return cable can seriously reduce system performance.

The following methods of installing fixed-type impressed-current anodes may be applied.

- Anodes can be bottom-installed on the ocean floor by mounting them on specially designed concrete sleds for stability. This minimizes the possibility of the anodes becoming covered with mud or silt.
- Anodes can be installed at the lower ends of protective vertical steel pipe casings or conduits attached to the platform. Casings should be attached to above-water platform members and supported at repeating members below water. The anodes should be lowered through the casings (which protect the anode lead wires) and be allowed to extend below a termination fitting at the bottom of each casing. This method provides a means of anode retrieval or replacement using the anode cable, without diver assistance. Marine growth or corrosion scale can make anode retrieval difficult or impossible. The top of the anode casing should be sealed with a removable cap to prevent any debris going down the casing.
- Anodes with essentially flat configuration-mounted, isolating-type holders can be attached directly to submerged platform members or to auxiliary structural members, such as vertical pipes, which can be removed for anode retrieval without diver assistance.
- Anodes can be installed on submerged platform members using offset steel structural support attached to the platform members. In this case, diver assistance is required for anode replacement.

Simple, rugged, easily maintained impressed-current equipment shall be used. The system can be based on manual, constant current or automatic potential control rectifiers.

NOTE 2 Because conditions at an offshore location seldom vary, except for weather-related factors, manually adjustable oil-cooled rectifiers with both a.c. and d.c. overload protection are commonly used.

There can be a delay of several months to a year or more between the time a pipeline is laid until permanent electrical power becomes available on the platform. Adequate CP of the pipeline for the interim period shall be provided.

Interference current corrosion on other pipelines and steel structures and reinforcement of concrete structures shall be assessed. Further guidance is given in Annex F.

13 Documentation

13.1 Design, manufacturing and installation documentation

The documentation for as-built systems shall cover the following:

- description of the basis of the CP design with reference to project specifications, codes and standards;
- calculations of surface areas to be protected and currents demanded;
- final design anode calculations including anode mass, dimensions, resistance, numbers and performance;
- drawings, including anode distribution, detailed anode design, manufacturing and installation.

The final documentation shall contain the engineering drawings and equipment lists updated to “as-built” status, and certification covering anode manufacturing and testing.

The following additional documentation shall be included for impressed-current systems:

- transformer-rectifier documentation, including capacity, control and alarm facilities and circuit drawings;
- detailed drawings of anodes, reference electrodes, subsea connectors, cable terminations and dielectric shields;
- procedures for fastening anodes, reference electrodes and dielectric shields, if applicable;
- documentation of impressed-current anode performance;
- drawings showing location of anodes and reference electrodes;
- detailed drawings of cables and electrical isolating joints, if applicable;
- drawings of cable protection conduits;
- documentation of potential-monitoring system.

A schedule of materials to be used for the installation of the CP system shall be issued, listing the specified materials in the quantities required to construct the CP system.

Construction details and installation procedures for the CP system shall be provided.

13.2 Commissioning procedures

For galvanic anode systems, commissioning is generally not necessary.

For impressed-current systems the commissioning procedures shall include:

- testing of pipeline isolation where present;
- energizing CP hardware, if necessary;
- measurement of adequate protection levels (see Annex D);
- interference testing, if applicable.

13.3 Operating and maintenance manual

For impressed-current systems, an operating and maintenance manual shall be provided containing:

- a description of the system and system components;
- a commissioning report;
- drawings for as-built components/systems;
- manufacturer/supplier documentation;
- potential criteria for the system;
- a monitoring plan, including procedures, schedules and equipment for each type of monitoring facility installed on the pipeline;
- guidelines for the safe operation of the CP system;
- maintenance procedures.

14 Operation, monitoring and maintenance of CP systems

14.1 General

Details of inspection and monitoring shall be performed in accordance with Annex D. Details of interference are given in Annex F.

14.2 Monitoring plans

A monitoring plan shall be written as part of the design.

The monitoring plan should consider the following:

- required types of measurement, such as pipe-to-seawater potentials, anode potentials, anode current outputs, visual inspection of anode dimensions, pipeline isolation testing, etc.;
- locations at which measurements are to be carried out;
- any permanent monitoring facilities;
- required monitoring installations and equipment to carry out such surveys;
- description of the techniques to be used, such as monitoring by divers, ROVs, trailing wires, towed fish, etc.; this description shall also include methods for accurately locating the pipeline, and the construction-phase requirements concerning the acquisition of navigation data for this purpose;
- frequency of each type of measurement.

This plan shall be part of the operating and maintenance manual.

14.3 Repair

Remedial measures shall be implemented if periodic surveys and inspections reveal that protection no longer meets the design criteria. In such cases the installation of additional anodes can be required.

Anode cables can be attached to the pipeline by mechanical fixing devices or by welding to an approved procedure (e.g. friction welding). Electrical resistance of such connections should be less than 0,1 Ω.

NOTE Mechanical fixing devices might not give reliable electrical connections for long-term applications.

Future inspections should include checks on all retrofitted galvanic anodes which rely upon mechanical contact with the pipeline for electrical continuity (e.g. the measurement of potential on both the anode and the pipeline immediately adjacent to the attachment point).

Annex A
(normative)

Galvanic anode CP design procedures

A.1 Introduction

Annex A specifies the detailed design procedures of CP systems based on galvanic anodes.

A.2 Subdivision of pipeline

Pipelines may be divided into sections where changes in conditions, such as water depth, operating temperature or burial, can give rise to variations in design current density.

A.3 Surface area calculations

For each pipeline section, the surface areas to receive CP shall be calculated separately where conditions cause different current requirements.

Components to be connected electrically to the pipeline, such as risers, expansion loops, tie-in spools, valves and tees, shall be included in the surface area calculations.

A.4 Current demand calculations

From the pipeline dimensions and the coating selected, the mean current demand, I_{cm}, and the final demand (I_{cf}) shall be calculated separately from Equation (A.1).

$$I_c = A_c \times f_c \times i_c \tag{A.1}$$

where

I_c is the current demand for a specific pipeline section calculated for mean and final conditions, in amperes;

i_c is the current density, selected for mean and final conditions (see 7.4), in amperes per square metre;

f_c is the coating breakdown factor determined for mean and final conditions (see 7.5);

A_c is the total surface area for a specific pipeline section, in square metres.

A.5 Selection of anode type and dimensions

The type of anode shall be determined from fabrication, installation and operational considerations.

The internal diameter of bracelet anodes shall be determined from the nominal outside diameter of the pipe plus maximum specified coating thickness, maximum pipe diameter tolerances and pipe ovality.

For pipeline bracelet anodes mounted flush with the concrete coating, the thickness of the concrete coating layer shall be taken into account when determining the overall dimensions of the anode.

The anode dimensions shall be sufficient to meet the required current demand at the end of the design life.

A.6 Total anode mass calculations

The total net anode mass required to maintain CP throughout the design life shall be calculated for each section of pipeline in accordance with Equation (A.2).

$$m = I_{\mathrm{cm}} \times t_{\mathrm{dl}} \times \frac{8\,760}{\mu \times \varepsilon} \tag{A.2}$$

where

m is the total net anode mass, for the specific pipeline section, in kilograms;

I_{cm} is the mean current demand for the specific pipeline section, in amperes;

t_{dl} is the design life, in years (7.3);

ε is the electrochemical capacity of the anode material per kilogram (8.3), in ampere hours;

μ is the utilization factor (8.4).

A.7 Calculation of anodes, dimensions and net mass

The final dimensions and net mass of the individual anodes shall be optimized, by carrying out a number of re-iterative calculations, using the equations below.

The total net anode mass is given by Equation (A.3).

$$m = n \times m_{\mathrm{a}} \tag{A.3}$$

where

n is the number of anodes to be installed on the specific pipeline section;

m is the total net anode mass, in kilograms, for the specific pipeline section [from Equation (A.2)];

m_{a} is the individual net anode mass, in kilograms.

The minimum number of anodes n shall be determined considering the maximum allowable anode spacing (8.1). For bracelet anodes, anode spacing is set at a fixed number of field joints. For sled anodes, the anode spacing is usually set at an easily defined spacing (e.g. the calculated spacing may be 1 187 m but a spacing of 1 000 m is selected).

NOTE 1 The anode manufacturers usually have standard-size moulds available for specific line sizes. Although Equation (A.3) is correct, in practice n and m_{a} are selected using Equation (A.4).

$$m > n \times m_{\mathrm{a}} \tag{A.4}$$

The required end-of-life individual anode current output, I_{f}, shall be calculated from Equation (A.5).

$$I_{\mathrm{f}} = \frac{I_{\mathrm{cf}}}{n} \tag{A.5}$$

where

I_{f} is the required end-of-life individual anode current output, in amperes;

I_{cf} is the total current demand for the protection of the specific pipeline section at the end of life, in amperes;

n is the number of anodes to be installed on the specific pipeline section.

For a given anode size and mass, the actual individual anode current output at the end of life, I_{af}, is calculated from Equation (A.6).

$$I_{\mathrm{af}} = \frac{E_{\mathrm{c}} - E_{\mathrm{a}}}{R_{\mathrm{a}}} \tag{A.6}$$

where

I_{af} is the actual end-of-life individual current output, in amperes;

E_{a} is the design closed-circuit potential of the anode, in volts (see Table 5);

E_{c} is the design protection potential, in volts, i.e. minimum negative potential (see Table 1);

R_{a} is the total circuit resistance, which is assumed to be equivalent to the anode resistance, in ohms (see A.8).

For determining the end-of-design-life anode-to-seawater resistance, the anodes shall be assumed to be consumed to an extent given by their utilization factor. The approximate anode dimensions corresponding to this degree of wastage shall be used in the anode resistance formula for R_{a} (see A.8).

NOTE 2 $E_{\mathrm{c}} - E_{\mathrm{a}}$ is generally referred to as the design driving voltage, in volts.

To provide the required current, the actual anode current output shall be greater than or equal to the required current output:

$$I_{\mathrm{af}} \geq I_{\mathrm{f}} \tag{A.7}$$

Equations (A.4) to (A.7) should be used to optimize the number, size and individual mass of the anodes to be used. For anodes that meet the criteria of Equations (A.4) and (A.7), an economic optimization may be carried out considering anode fabrication and installation cost.

A.8 Anode resistance equations

The anode resistance shall be calculated as follows:

a) for bracelet anodes

$$R_{\mathrm{a}} = 0{,}315 \times \frac{\rho}{\sqrt{A}} \tag{A.8}$$

b) for slender anodes:

$$R_{\mathrm{a}} = \frac{\rho}{2 \times \pi \times L} \times \left(\ln \frac{4L}{r} - 1 \right) \tag{A.9}$$

where

R_{a} is the anode resistance, which is assumed to be equivalent to the total circuit resistance, in ohms;

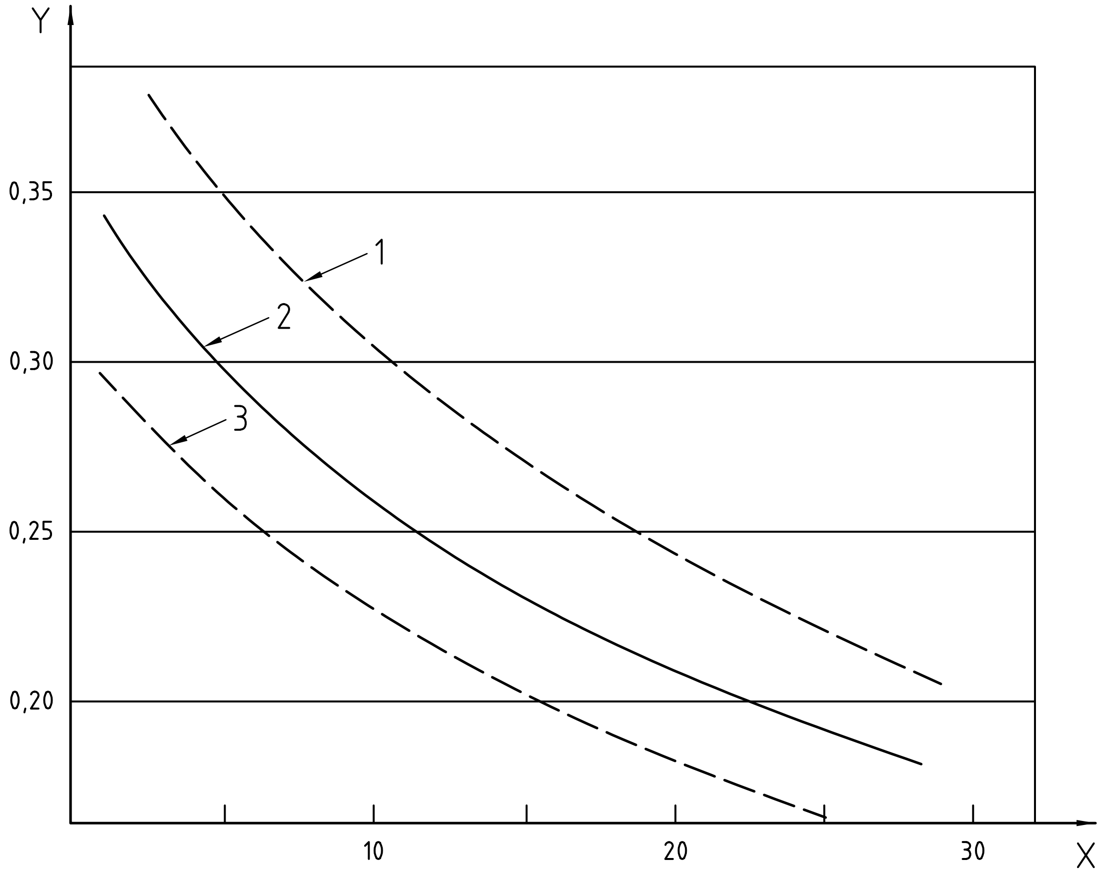
ρ is the environmental resistivity, in ohm metres;

L is the length of the anode, in metres;

r is the radius of the anode, in metres;

A is the exposed surface area of the anode, in square metres.

Typical seawater resistivities are shown in Figure A.1.



Key

X temperature, °C

Y seawater resistivity, ρ, Ω·m

1 salinity 3,0 %

2 salinity 3,5 %

3 salinity 4,0 %

Figure A.1 — Seawater resistivity as a function of temperature for salinities 3,0 % to 4,0 %

For anodes exposed to seabed environments, the resistivity should be assessed by measurements or previous experience. If no data are available, 1,5 Ω·m should be used.

For non-cylindrical anodes, the radius, *r*, in Equation (A.9) shall be calculated from Equation (A.10).

$$r = \frac{C}{2\pi} \tag{A.10}$$

where

r is the radius of the anode, in metres;

C is the cross-sectional perimeter, in metres.

Other anode resistance equations may be validated by theory and/or testing.

A.9 Design adjustments for varying conditions

The coating breakdown factor, f_c, and the electrochemical capacity, ε, used in the typical CP design assume that the operating conditions for the pipeline will not vary over the life of the pipeline. If this assumption is not correct, the values used in Equations (A.1), (A.2) and (A.6) will not be constants, but will vary as the operating conditions change. The impact of these varying conditions upon the CP design may be evaluated by repeating the design calculations at the extremes of the expected conditions. If the difference between the two anode designs is small, the most conservative design should be used. However, if the number of anodes required by the two designs is significantly different, a design that addresses these changes may be developed.

EXAMPLE 1 For high-temperature pipelines installed several years before the start of production, cathodic current requirement during the period prior to start-up will be less due to the cooler temperature.

EXAMPLE 2 For buried flowlines that can experience increasing operating temperatures as water production increases later in its operating life, cathodic current requirements will be much less during the initial period of production than in the later high-temperature period. Since the anode operating temperature can change with time, the electrochemical capacity can vary as the temperature increases.

EXAMPLE 3 Pipelines with exceptional coating quality and a high cathodic current density requirement, such as deepwater insulated lines, may require such small amounts of current that the anode current density of a conventional anode bracelet design is below 1 000 mA/m^2. The electrochemical capacity of aluminium alloys is not a constant value at anode current densities below 1 000 mA/m^2.

Anode electrochemical capacity is usually tabulated as high and low temperature values at anodic current densities in excess of 1 000 mA/m^2. For normal operating temperatures less than 50 °C and anode current densities over 1 000 mA/m^2, this variation may be ignored.

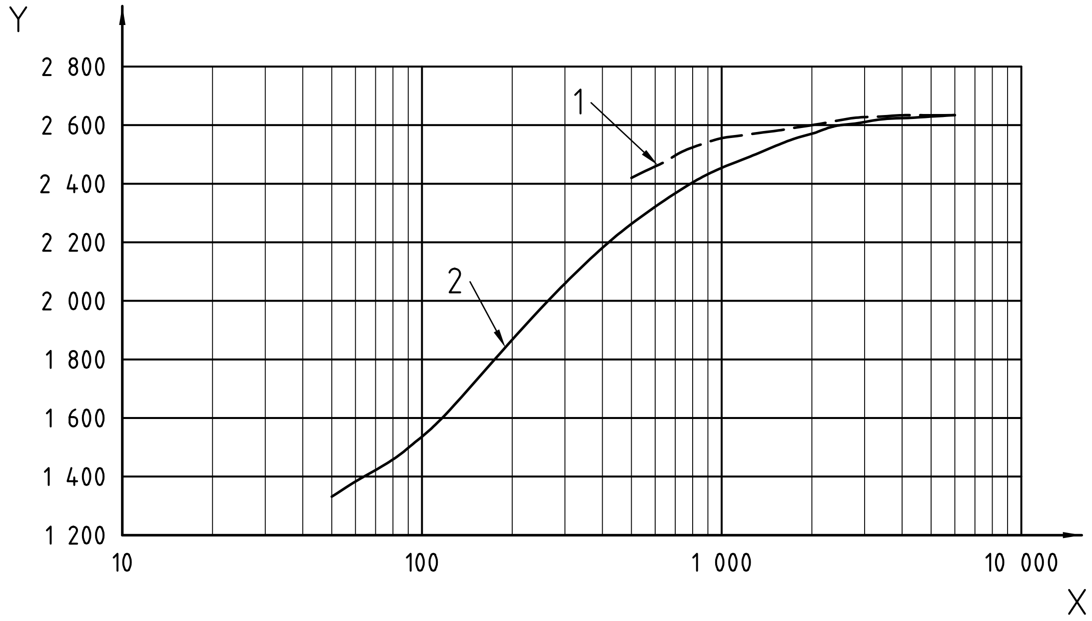
NOTE Examples 2 and 3 listed above describe applications that fall either outside the normal anode operating envelope or where the operating conditions will change over the life of the anode (as an example, see Figure A.2 which gives curves of anode electrochemical capacity versus anode current density for two specific temperature ranges). In these situations, the anode electrochemical capacity, ε, changes over the life of the pipeline.

To account for these changing conditions, a single value for the anode electrochemical capacity may not be appropriate in Equation (A.2). If variable electrochemical capacities are envisaged, then Equation (A.2) should be revised by Equation (A.11).

$$m = \frac{A_c \times 8\,760}{u} \int_t i_c \times f_c \times \frac{1}{\varepsilon}\, dt \qquad \text{(A.11)}$$

where i_c, f_c and ε are not constant values but vary over the design life of the pipeline.

Information about ε as a function of temperature and/or current density may be obtained in accordance with Annex C. Normally, these calculations are performed as numerical integrations using a spreadsheet that allows the annual value for m to be calculated and then summed over the life of the pipeline.



Key

X anode current density, mA/m^2

Y anode electrochemical capacity, A·h/kg

1 $T = 2$ °C

2 $T = 25$ °C to 28 °C

Figure A.2 — Aluminium anode performance in seawater at low current densities

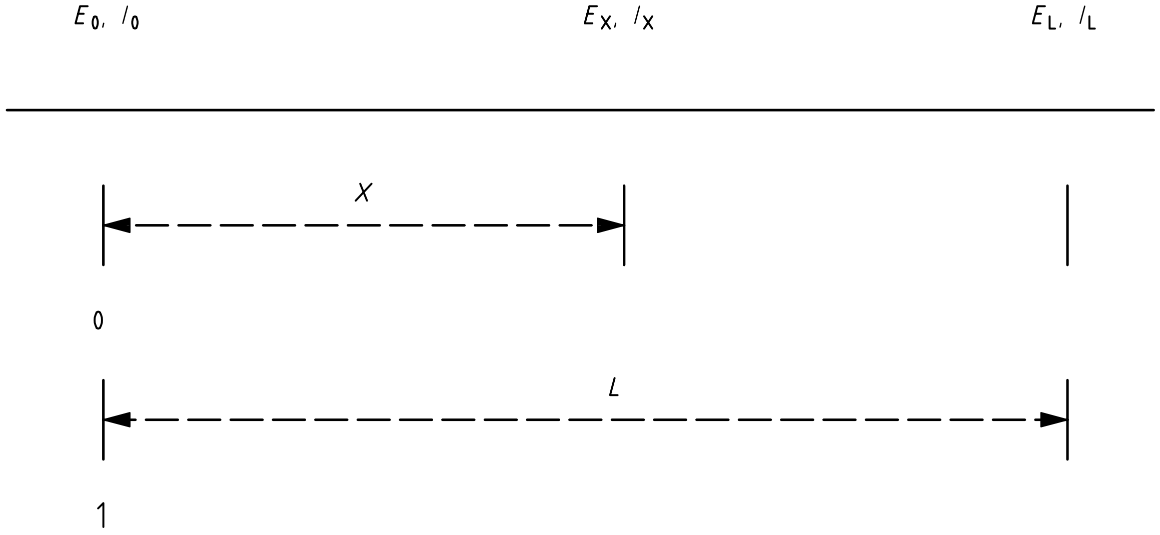
Annex B
(normative)

Attenuation of protection

B.1 Introduction

Once the number, size and spacing of the anodes have been determined in accordance with Annex A, an approximate check on the suitability of the anode distribution can be carried out using attenuation equations. Using these equations, it is possible to obtain an indication of the distribution of the pipe-to-electrolyte potential and the current flowing onto the pipeline a function of the distance from the drain points (i.e. anodes).

Figure B.1 provides an illustration of the potential and currents as a function of the distance from the drain point.



Key

1 drain point

NOTE The symbols used in this figure are defined in B.2.

Figure B.1 —Drain point definition

B.2 Method

For a pipeline with multiple drain points (anodes) at a uniform spacing of 2L, the potential, E_x, and current, I_x, at any distance x from the anode shall be calculated using Equations (B.1) and (B.2):

$$E_x = E_0 \times \frac{\cosh \alpha \left(L - x \right)}{\cosh \alpha \, L} \tag{B.1}$$

$$I_x = I_0 \times \frac{\sinh\alpha\left(L-x\right)}{\sinh\alpha L} \tag{B.2}$$

where

E_0 is the pipe-to-electrolyte potential shift at the drain point (anode), in volts;

E_x is the pipe-to-electrolyte potential shift at a distance x from the drain point, in volts;

I_0 is the current flowing onto the pipe at the drain point (anode), in amperes;

I_x is the current flowing onto the pipe at a distance x from the drain point, in amperes;

L is half the distance between drain points, in metres;

R_L is the linear electrical resistance of the section of the pipeline, in ohms per metre, and is given by: $R_\mathrm{L} = \frac{\rho}{A_\mathrm{w}}$;

R_t is the leakage or transverse resistance, in ohm metres, and is equal to $\frac{R_0}{\pi D_\mathrm{o}}$;

R_0 is the pipe-to-electrolyte insulation resistance, in ohm square metres;

ρ is the specific resistance of the pipeline material, in ohm metres;

D_o is the external diameter of the pipeline, in metres;

A_w is the cross-sectional area of the pipe wall, in square metres;

α is the attenuation constant for the pipeline section, in reciprocal metres, and is equal to $\sqrt{\frac{R_\mathrm{L}}{R_\mathrm{t}}}$.

A value for the insulation resistance R_0 should be selected based upon practical experience and consider the following:

- type of coating;
- exposure conditions such as to seawater or seabed sediments;
- design life of the pipeline and anticipated progressive reduction in coating resistance over the design life;
- pipeline installation method and projected extent of coating damage.

The linear electrical resistance of the section of the pipeline R_L may be calculated from Equation (B.3):

$$R_\mathrm{L} = 4L \cdot \frac{\rho}{\pi\left(D_\mathrm{o}^2 - D_\mathrm{i}^2\right)} \tag{B.3}$$

where

D_o is the outer diameter of the pipeline;

D_i is the inner diameter of the pipeline;

L is half the distance between the drain points, in metres.

Alternatively, values for the electrical resistance for standard pipe sizes may be obtained from tables in Reference [11].

B.3 NORSOK procedure

The procedure given in this clause may be used for determining the maximum distance between anodes.

NOTE Reference [13] provides further information for this method. Using this method, the maximum voltage drop is calculated by assuming that the whole area with coating breakdown is located halfway between the anodes.

The voltage drop (or potential increase) between two anodes for a CP design based on anodes equally distributed along the pipeline should be calculated using Equation (B.4).

$$\Delta E_{\mathrm{Me}} + \Delta E_{\mathrm{A}} = \frac{L^2 \times \rho_{\mathrm{Me}} \times i \times f_{\mathrm{cf}} \times D}{4 \times d \times (D - d)} + R_{\mathrm{anode}} \times i \times \pi \times D \times f_{\mathrm{cf}} \times L \qquad \text{(B.4)}$$

where

ΔE_{A} is the IR drop due to transporting the current from anode to cathode, electrolytic potential drop (V);

ΔE_{Me} is the IR drop due to transporting the current in the pipe wall, metallic potential drop (V);

R_{anode} is the anode resistance which is assumed to be equivalent to the electrolytic resistance, in ohms;

ρ_{Me} is the resistivity of the pipe wall material, in ohm metres;

L is the length between anodes, in metres;

i is the current density, in A/m^2;

f_{cf} is the final coating breakdown factor (see 7.5);

D is the pipeline outer diameter, in metres;

d is the pipeline wall thickness, in metres.

For anodes distributed along a pipeline, loss of one anode shall be taken into account when calculating the maximum distance between the anodes; see also 8.1.

For a CP design with anode banks located at the pipeline ends only, the voltage drop (or potential increase) between the two anode banks should be calculated using Equation (B.5).

$$\Delta E_{\mathrm{Me}} + \Delta E_{\mathrm{A}} = \frac{L^2 \times \rho_{\mathrm{Me}} \times i \times f_{\mathrm{cf}} \times D}{4 \times d \times (D - d)} + \frac{R_{\mathrm{anode}} \times i \times \pi \times D \times f_{\mathrm{cf}} \times L}{2} \qquad \text{(B.5)}$$

Equation (B.5) is valid only if the pipeline section and the anode pipe joints are unaffected by other installations at the pipeline ends. If this condition is not fulfilled and such structures can draw current from the anodes, then the last part of Equation (B.5), which represents the voltage drop from the anode, shall be further developed to account for such effects. A special assessment of the anode voltage drop shall also be made when the pipeline is protected from anodes on a structure at the pipeline end. In cases where end mounted anodes are used in combination with anodes or anode spools along the pipeline, a combination of Equation (B.4) and Equation (B.5) shall be used.

Annex C
(normative)

Performance testing of galvanic anode materials

C.1 General

This annex provides a procedure for laboratory testing for determining performance values for galvanic anodes in a given environment.

The performance of galvanic anode materials may also be validated by field experience, either by using data from monitored anodes or by dedicated field-testing of full-size anodes.

This procedure is also applicable to special environments, such as hot seawater or sediments.

Performance testing shall be carried out for new (nominal) anode compositions and/or foundry, and whenever there is a need to verify anode material performance.

C.2 Sampling and preparation of test specimens

Material for testing shall be sampled either from manufactured anodes or from special castings using the same raw materials and melting practice as for normal production.

Two specimens shall be prepared from materials representing a minimum of five heats. The chemical composition of the material test samples shall be representative of normal production, i.e. the content of alloying and impurity elements shall reflect the manufacturers' internal composition limits for the anode material.

Cylindrical specimens with a minimum diameter of 20 mm and a minimum length of 80 mm shall be machined from the sample material.

A hole with a diameter of approximately 2 mm shall be drilled through the test specimen, tapped at one end and connected to a titanium support rod. The support rod shall have an electrically insulating coating on all areas which will be exposed to the test solution.

After mounting on the support rod, the specimen ends shall be coated by a sealing compound such as polychloroprene glue or silicone rubber.

Prior to exposure, the test specimens shall be rinsed in tap water and then dried with ethanol or equivalent. After drying, the specimens shall be weighed to the nearest 0,1 mg.

C.3 Testing equipment and experimental procedure

The testing environment shall be clean natural seawater with a salinity ≥ 3,0 % mass fraction. The temperature of the testing environment may vary in the range +7 °C to +20 °C. Temperature and salinity of the test environment shall be recorded at least once per week.

The test cells shall be configured as outlined in Annex E with a continuous exchange of seawater in the cell at a rate of at least 1 l/min. The seawater shall be continuously purged with air.

Testing shall be performed as a free-running test.

The duration of the test shall be a minimum of 12 months.

The integrated current may be determined by a coulometer or by recording the voltage drop across the precision resistance to be introduced in the circuit. Manual readings of the integrated current shall be taken at least once a week.

Manual recordings of anode potentials (see Annex E) shall be taken at least once a day for 5 days during the first 2 weeks of testing, and at least once a week thereafter. Continuous recording may be used as an alternative.

The anode and cathode areas shall be connected across a 10 Ω precision resistor in order to limit the anode current density. Higher and lower circuit resistances (e.g. 2 Ω to 20 Ω) may be applied if more extensive data are required. The cathode surface area shall be at least 30 times the exposed anode surface area.

The anode current density shall be calculated from the voltage drop across the 10 Ω circuit resistance using a high-impedance ($>10^7$ Ω) voltmeter.

Measurements of current and anode potential shall be made at regular intervals. Steel cathode potentials shall also be recorded at the same time.

The electrochemical capacity shall be calculated as specified in Annex E.

C.4 Documentation

A test report containing the following shall be prepared:

a) data from melting and casting of the test material, including alloying and impurity elements affecting anode performance;

b) nominal composition and guaranteed compositional limits;

c) specimen preparation, testing equipment and procedures;

d) environmental data, including seawater temperature and salinity;

e) anode potentials presented graphically as a function of time;

f) photographs of anode specimens prior to and after cleaning;

g) electrochemical capacity, in ampere hours per kilogram.

Annex D
(normative)

CP monitoring and surveys

D.1 Introduction

A number of methods may be employed to monitor the effectiveness of offshore pipeline CP. The level of monitoring shall be commensurate with the criticality and condition of the pipeline, and minimum requirements of regulations.

A post-installation survey should be carried out within 12 months of pipeline installation in accordance with D.6.1.

Further surveys should be considered based on:

- CP design and anode performance in accordance with this part of ISO 15589;
- results from the initial survey;
- reported excessive anode consumption;
- presence of coating damage which may result in breakdown factors larger than those given in Tables 3 and 4; and
- potential interference with neighbouring pipelines and structures.

If the pipeline is to remain in service beyond its original design life, then at least one potential survey shall be performed within the last 5 years of the design life of the CP system (see D.6.2).

D.2 Topside potential monitoring

Measurements of potentials applied to pipeline risers may be carried out by using a simple portable reference electrode and a conventional voltmeter. The voltmeter negative terminal shall be connected to the riser above the water line, and the positive terminal to the reference electrode. The reference electrode shall be lowered into the water alongside and, to ensure accuracy, as close as possible to the riser. Potentials shall be recorded at different depths determined from markers attached to the reference electrode cable.

NOTE 1 Motion of the water and loss of visual contact with the reference electrode reduces measurement accuracy. However, accuracy can be restored if a diver is employed to ensure good positioning of the reference electrode. When divers or ROVs are used for measuring potential, specially designed contact probes are used (see D.4.3.1). Electrical contact between the riser and host structure shall be checked, if considered possible, prior to reading potentials.

NOTE 2 The potential of risers can be influenced by the host structure if in electrical contact with the host structure. However, the potential of the riser is not necessarily a good indicator of the potential profile along the whole pipeline.

The potential on short pipelines running between two platforms may be modelled using attenuation equations, and the worst-case potential value predicted from the potentials measured at the extremities. Potential measurements shall be carried out at intervals along the pipeline for verification of model reliability.

NOTE 3 The length of such pipelines is dependent upon pipe wall thickness and diameter, external coating condition, operating temperature, degree of burial, end-point potentials, impressed-current anode location, galvanic anode condition and spacing, and whether or not the pipeline is effectively isolated from the host structure(s).

D.3 Visual inspection

Visual inspection of unburied sections should be carried out when necessary to check the condition of the pipe, coating and CP system. The type of data to be gathered during the inspection shall be documented prior to the inspection and be appropriate for the needs of the pipeline.

NOTE Direct visual inspection by divers or ROV cameras can disclose deficiencies of a CP system, such as damaged or missing anodes, damaged cables, excessive anode consumption. Apparent corrosion damage or rust discoloration can be another sign of under-protection. Low anode consumption can indicate passivation, and heavy calcareous deposits close to the anodes can indicate overprotection.

Galvanic anode surfaces should be cleaned before any physical measurements of anode dimensions are taken.

D.4 Potential measurements

D.4.1 General

Potential measurements should be taken to assess the performance of the CP system in accordance with this part of ISO 15589.

The objective of potential measurements is to determine the actual potential at the pipe-to-seawater interface with respect to a reference electrode, such that the effectiveness of CP can be assessed. Acceptance criteria are given in Table 1 and may be converted for different reference electrodes as detailed in D.4.2. Normally it is difficult to measure pipe-to-seawater potentials directly, as bare steel is not usually available. In such cases, indirect potential measurements should be considered.

Potential measurements should also be taken at galvanic anodes to obtain information on their performance.

When CP is achieved using impressed-current systems, the potential shall be measured with the protective current applied.

NOTE 1 The value includes the voltage drop across the steel/water interface, and also includes the voltage drop in the seawater between the reference electrode and the pipe.

In most circumstances, except near impressed-current anodes, the voltage drop in the seawater may be taken as zero.

Test equipment shall be maintained and periodically calibrated. Reference electrodes shall be checked for contamination and routinely calibrated against a standard laboratory-grade reference electrode.

Reference electrodes shall be positioned as close to the pipeline as practical, in particular for measurements of anode potentials with large voltage drops in the seawater adjacent to the anode. In these cases, the IR drop shall be compensated for when interpreting the measured anode potential in terms of the true anode potential.

Anode potentials should be more negative than the design closed-circuit anode potential.

NOTE 2 More positive recordings indicate excessive current load or passivation behaviour.

Electrical safety shall be observed when divers work on pipelines protected by an impressed-current CP system.

The steel/sea water potential shall be measured to determine whether a structure is adequately protected. For such measurements, connections shall be made to both the structure and the electrolyte.

NOTE 3 The connection to the structure is a simple metallic one but, for the connection to the electrolyte, a metal conductor has to be introduced into the electrolyte. This conductor introduces its own electrode potential, which inevitably becomes included in the measured value. This situation can be resolved by using a conductor of reproducible and defined electrode potential; this is called a reference electrode. Irrespective of the type of reference electrode used, it is essential that it be placed very close to the metal surface as the measurement of the potential difference between the metal surface and the electrolyte can be considerably affected by the potential drop produced by the protection current as it flows through the surrounding electrolyte to the structure. This effect, known as the IR drop, has the effect of making the measured potential more negative than the actual potential at the metal/electrolyte interface. The IR drop is dependent on electrolyte resistivity and is particularly relevant to buried structures. The resistance of any coatings will also have an effect.

D.4.2 Reference electrodes

Reference electrodes such as the saturated calomel electrode or various silver/silver chloride electrodes with different concentrations of KCl electrolyte may be used as master reference electrodes. Two electrodes in the same assembly, to give an on-line cross-calibration, should be considered for potential-monitoring devices.

NOTE 1 Saturated calomel electrodes or silver/silver chloride/potassium chloride electrodes are not often used for monitoring and controlling cathodic protection systems in seawater because they are insufficiently robust for field use. Reference electrodes used more often in the field are silver/silver chloride/seawater electrodes or high-purity or anode-alloy-specification zinc electrodes. These electrodes are considered sufficiently accurate for most practical purposes even if the electrolyte is not fully defined and reproducible. The silver/silver chloride/seawater (Ag/AgCl/seawater) electrode is the most widely used electrode for seawater applications, particularly in conjunction with portable monitoring equipment.

Other reference electrodes that may be used in place of the Ag/AgCl/seawater reference electrode are described below, with the respective protection potentials for carbon steel equivalent to the −0,80 V versus Ag/AgCl/seawater criterion.

a) Saturated copper/copper sulfate reference electrode (CSE). The least negative potential measured against this electrode shall be −0,85 V. This electrode is more commonly employed for determining the level of protection on onshore pipelines and is not sufficiently stable in seawater for long-term immersion in this environment. It is not recommended for use in seawater.

b) High-purity metallic zinc electrode. “High purity” (ASTM B418, type II, or EN 12496, alloy type Z2) or a zinc alloy used for anode manufacturing (US Mil Spec A-18001K or EN 12496, alloy type Z1 or Z3) have a moderately stable potential in seawater and are sometimes used as a reference electrode. However, zinc electrodes are less accurate than silver/silver chloride reference electrodes, and are mostly used in permanent monitoring applications. For permanent installations, a small anodic current should pass through the surface to keep it clean and active. The least negative potential for effective CP of carbon steel versus the zinc/seawater electrode is +0,25 V.

c) Saturated calomel reference electrode (SCE). This electrode comprises mercury and mercurous chloride in a saturated solution of potassium chloride. The least negative potential for effective CP of low-alloy steel is −0,78 V. This electrode is not normally used for site surveys and is more suitable for laboratory applications.

d) Saturated silver/silver chloride (Ag/AgCl/saturated KCl). This electrode is similar to the silver/silver chloride/seawater electrode, except that the silver/silver chloride is immersed in a saturated solution of potassium chloride and the potential is not affected by the salinity (or resistivity) of the seawater. The least negative potential for effective CP of low-alloy steel using this electrode is −0,76 V. As with SCE, the saturated silver/silver chloride electrode is more suitable in laboratory applications.

Reference electrodes used in the field shall be periodically checked with a master reference electrode having a valid calibration certificate. The master electrode shall be calibrated periodically with a minimum frequency of once a year to a primary calibration reference electrode (normal hydrogen electrode; NHE).

Reference electrodes such as the saturated calomel electrode or various silver/silver chloride electrodes with different concentrations of KCl electrolyte may be used as master reference electrodes.

NOTE 2 The official reference electrode is the standard hydrogen electrode (SHE). This electrode considers the fugacity coefficient for hydrogen gas and the activity coefficient for H^+ ions but is practically impossible to manufacture.

D.4.3 Direct contact instruments

D.4.3.1 Contact probes

Potential measurements may be made above water using a conventional voltmeter connected to the reference electrode via a cable, and a second cable from the metal tip of the contact probe to the negative terminal on the voltmeter. The second cable should not be connected to the above-water section of a pipeline riser.

NOTE Contact probes comprise a reference electrode in a robust housing with a metal tip to make direct contact with the pipeline. They are designed for diver- or ROV-assisted potential surveys. They can be used in proximity mode, similar to topside monitoring (see D.2), but have the added ability to contact the structure locally via the metal tip. This is important if a pipeline is isolated and topside ground connection to the voltmeter is not possible.

Potential measurements may also be made by self-contained contact probes which are similar to the tip-contact probe, but in addition to the reference electrode have an integral voltmeter and do not require any cables back to the surface. These probes can be diver-held or ROV-mounted, and only work in the tip-contact grounding mode. Readings are displayed subsea and are either recorded visually, on video tape, or relayed verbally to a surface data recorder by the diver.

D.4.3.2 Fixed/permanent systems

Critical pipelines, such as those operating at high temperatures, inaccessible risers or pipelines in environmentally sensitive areas, can be equipped with permanent CP monitoring facilities. For these pipelines, a number of devices can be used, such as permanent reference electrodes, steel coupons for contact to pipeline, current density coupons (either bare steel or coated), and anode current monitoring shunts.

Monitoring devices should be connected to a topside facility such as a data logger via a cable or interrogated via an acoustic link. Battery life, cost and practicality should be considered for acoustically linked devices.

NOTE 1 Acoustically linked devices require battery packs, and interrogating them is a labour-intensive task.

NOTE 2 Distribution of monitoring devices over the entire length of the pipeline is impractical. Permanent monitoring facilities are more appropriate for risers or on sections of the pipeline within a fairly short distance from the platform or the shoreline.

D.5 Anode current measurements

Current density and electric field gradient measurements may be used to verify that galvanic anodes in unburied pipelines are active. For buried pipelines, locating anodes can be more restricted, and tracking capabilities, depth of burial and anode current output should be considered. Calculation of anode current output can be performed if highly accurate measurements of the magnitude and direction of the electric field or current are available.

NOTE There are several techniques for on-line measurements of galvanic anode current output. Such data are applicable to calculations of remaining anode life and can be used to optimize future designs.

D.6 Surveys

D.6.1 General

An underwater visual survey for main trunklines and other critical pipelines shall be conducted during or after the installation to determine if any damage to the CP system has occurred. The survey may include a determination of the pipeline potential along its length, current output from galvanic anodes from field gradient measurements, and coating condition assessments. If a baseline survey for a galvanic anode CP system confirms that the corrosion-control system is working as designed, it may not be necessary to carry out the next CP survey on the pipeline for many years.

Results from previous inspections should be used for planning future inspections. Attention shall be concentrated to areas where marginal or insufficient CP has been identified during previous surveys and in areas where damage to anodes and/or coating has been reported.

Localized or full-length surveys shall be carried out more frequently where inadequacies in the level of protection are known or suspected, due to

— known shortcomings in the original CP design,

— damage to the pipeline or the CP system,

— damage from third-party interference,

— pipeline approaching the end of the CP system design life if intended to operate beyond.

Where complete periodic surveys are impossible because of inaccessibility, surveys may alternatively be carried out on a sampling basis.

Buried pipelines are in general difficult to survey, as visual examination for coating condition and damage to CP facilities, in particular anodes, is not possible. Account should be taken of this in risk assessments.

D.6.2 Methods

Different survey methods, including potential measurement by direct contact with the pipeline or field gradient measurements using two or more reference electrodes at fixed distances from each other and from the pipeline, are available.

The most complete and accurate systems of potential measurement employ a diver or ROV to physically swim along the pipeline and take point readings at intervals, using a CP probe with a tip contact and an in-built reference electrode. These are often referred to as “stab” readings. Installation of coupons should be considered to ensure proper measurements. Attenuation models may be used to predict the potential distribution between successive measurement points.

NOTE For concrete weight-coated pipelines where the coating is in good condition, this technique can be very limited as contact readings to anodes do not provide information on protection level.

One survey method, which overcomes the problem of being unable to contact the pipe directly, uses fixed reference electrode arrays at a known distance from the pipeline. The arrays shall be mounted on the ROV with two or more reference electrodes at measurable distances apart. The ROV shall move along the pipeline at a fixed distance, and shall measure electrical field gradients around the pipe due to the CP current in the seawater. Using computer software, these measurements can be converted into pipe-to-seawater potentials and the potential profile along the pipeline can be determined. Electric field gradient measurements can be used for assessing current density levels on anodes and pipeline, and for locating coating defects.

A less accurate survey method utilizes a submerged sensor or “fish”, towed along by a surface vessel. With this technique, electrical contact is made to the pipeline via a trailing wire connected to the pipeline at the landfall or the riser. The surface vessel shall follow the route of the pipeline, towing the “fish” behind it. The potential of the pipeline shall be measured continuously with respect to the reference electrode mounted on the “fish”. The accuracy of the potential measurements is determined by the position of the “fish” with respect to the pipe, and benefits therefore are limited.

If divers or ROVs are performing other activities to pipelines, such as completing tie-ins, inspecting spans, carrying out repairs or re-burial, opportunity should be taken to gather CP data.

If an insulated pipeline system has become waterlogged, cathodic protection cannot be very effective. Additional means of assessing possible corrosion of the pipeline (e.g. intelligent pigs) should be considered and a survey plan developed accordingly.

D.7 Inspection of impressed-current system components

Sources of impressed current shall be checked six times per calendar year at intervals not exceeding 2,5 months. The voltage and current output shall be measured, and shall be close to the values obtained upon completion of commissioning.

Reverse-current switches, diodes and interference bonds, whose failure would jeopardize pipeline protection, shall be inspected for proper functioning six times per calendar year at intervals not exceeding 2,5 months.

Impressed-current system facilities shall be inspected once each calendar year, at intervals not exceeding 15 months, to minimize in-service failures. These inspections should include a check for electrical short-circuiting, grounding connections, meter accuracy, efficiency and circuit resistance.

The effectiveness of the electrical isolating devices and continuity bonds shall be evaluated during the periodic surveys.

D.8 Safety

Relevant statutory safety regulations shall be followed where divers work on pipelines protected by impressed-current CP systems. The main dangers can arise from any CP system, but those generally limited to impressed-current systems are physical obstruction, electric shock and flammable, toxic or pressure-energy hazards.

The d.c. supply of anodes shall be switched off during diving operations not directly related to CP systems and any diving inspections carried out close to impressed-current anodes. However, diving CP inspections may be performed with the impressed-current system in operation, provided all relevant safety regulations and precautions are observed.

D.9 Documentation

Inspection reports shall contain measurement procedures, locations, and results and data from installed on-line monitoring systems.

Historic data of periodic inspections and on-line monitoring should be kept such that long-term trends become apparent and can be analysed. This can be achieved using dedicated software.

An inspection survey report shall be provided when the data are processed and interpreted, and should include the following:

— description of the operations performed;

— technical characteristics and operating parameters of the monitoring equipment used;

— any corrections applied to the records;

— plotted graphs of pipe potential along the pipeline;

— measured field gradients (if required);

- measured resistivity values (if required);
- original recordings on paper and on magnetic or optical storage medium;
- comparison of the recorded data with those recorded at previous surveys.

Annex E
(normative)

Laboratory testing of galvanic anodes for quality control

E.1 General

This laboratory test procedure should be used for quality control of aluminium and zinc materials during production of galvanic anodes. The results should not be used for CP design because the electrochemical data obtained from short-term testing may not be representative of long-term performance.

E.2 Sampling and preparation of test specimens

Unless otherwise specified, quality control of electrochemical properties (anode potential and electrochemical capacity) shall be carried out for each 15 t of anodes produced.

Specimens for testing may be cut from a production anode from each batch, or cast separately.

NOTE Cast specimens are likely to produce the most representative results.

Test specimens shall be cylindrical with a diameter of 10 mm ± 1 mm and a length of 50 mm ± 5 mm. Identification marking shall be maintained throughout preparation and testing.

A hole approximately 2 mm in diameter shall be drilled through the test specimen, tapped at one end and connected to a titanium support rod which shall have an electrically insulating coating on all areas to be exposed to the test solution.

Prior to exposure, the test specimens shall be rinsed in tap water, dried using ethanol or equivalent and weighed to the nearest 0,1 mg.

After mounting on the support rod, the specimen ends shall be coated with a suitable sealing compound such as polychloroprene glue or silicone rubber.

E.3 Equipment and experimental procedure

The testing solution shall be natural seawater or artificial seawater in accordance with ASTM D1141. A minimum of 10 l of test solution per specimen shall be used. The test solution shall be continuously purged with air, maintained at a temperature of 20 °C ± 3 °C and shall not be changed for the duration of the test.

Each specimen shall be suspended in the centre of an uncoated cylindrical steel container or pipe segment, the wetted surface shall be at least 20 times the anode specimen area, i.e. minimum 400 cm^2.

Galvanostatic control shall be carried out by means of a constant d.c. current source. The specimen and the steel cathode shall be coupled to the positive and negative terminals respectively. Multiple testing cells may be connected in series to one d.c. source. A copper coulometer current integrator or an electronic device, capable of determining the total discharged current to an accuracy of ±2 %, shall be installed into the circuit containing one or more test cells arranged in series.

The current through the cell(s) shall be adjusted to provide anode current densities, based on the initial exposed specimen surface area, in accordance with the following scheme:

- Day 1: 1,5 mA/cm^2
- Day 2: 0,4 mA/cm^2

- Day 3: 4,0 mA/cm^2
- Day 4: 1,5 mA/cm^2

The current density shall be controlled to an accuracy of ±0,1 mA/cm^2 and shall be maintained for a period of 24 h ± 1 h for a total testing time of 96 h ± 4 h.

At the end of each test period, the anode potential shall be measured at three positions per specimen. A standard reference electrode with an electrolyte bridge (e.g. a Luggin capillary) shall be applied. The tip of the bridge shall be positioned within 1 mm of the specimen surface, which shall not be cleaned of corrosion products prior to taking measurements.

After completion of a full test period, the specimens shall be cleaned of corrosion products. Aluminium specimens shall be cleaned for 10 min at 80 °C in a solution containing 20 g chromium trioxide and 30 ml concentrated phosphoric acid per litre of water. Zinc specimens shall be immersed for 2 h in a saturated ammonium chloride solution at ambient temperature. The test specimens shall be rinsed in tap water, dried in ethanol, or equivalent, and weighed to the nearest 0,1 mg. The electrochemical anode capacity shall be calculated using Equation (E.1):

$$\varepsilon = Q/\Delta m \tag{E.1}$$

where

ε is the electrochemical capacity, in ampere hours per kilogram;

Q is the total electric charge, in ampere hours;

Δm is the specimen mass loss, in kilograms.

E.4 Acceptance criteria and retesting

In case of failure to meet the specified requirements, retests may be carried out on three specimens from each heat that failed to meet the requirements. Failure of any of these three specimens to meet the specified requirements should lead to rejection of all anodes from the heat(s) involved or to other actions being taken as agreed prior to fabrication.

E.5 Documentation

A test report containing the following shall be prepared:

a) data for the test material, including heat number, chemical composition and casting date;

b) specimen preparation, test equipment and procedures;

c) recorded potentials, presented in a tabular form;

d) anode mass loss and total current charge;

e) calculated anode electrochemical capacity.

Annex F
(informative)

Interference

F.1 General

This annex provides guidance for the detection and control of a.c. and d.c. interference currents for pipelines.

Corrosion caused by interference current on submerged pipelines differs from other causes of corrosion damage in that the current which causes the corrosion has a source foreign to the affected pipeline. Typical sources of interfering currents are d.c. electrical power cables, welding, direct electrical heating systems and foreign impressed-current systems.

Galvanic anode systems do not cause interference-current problems on foreign neighbouring structures.

Detrimental effects of interference currents occur at locations where the currents are transferred between the affected pipeline and the electrolyte (seawater or seabed).

F.2 Control of interference currents

Tests should be conducted in areas where interference currents are suspected. The type of test depends on water depth and accessibility of the pipeline. Any one or a combination of the following test methods can be used:

- measurement of the pipe-to-electrolyte potentials with recording or indicating instruments, using field gradient or a similar continuous potential measurement technique;
- measurement of the variations in current output of the suspected source of interference current, and correlation with measurements obtained with the method described above.

NOTE Interference current corrosion on a submerged pipeline can be caused by a neighbouring foreign structure not electrically bonded to the subject pipeline. Current from such foreign structure finds its way onto the pipeline via low-resistance paths in the seawater. Accelerated corrosion of the pipeline can occur at locations where the interference current discharges into the electrolyte from the pipeline and returns to the foreign structure.

F.3 Interference from direct current

F.3.1 Measurements

In areas where d.c. interference currents are suspected, appropriate tests shall be conducted. Any one or any combination of the following test methods should be employed by measuring:

- pipeline potentials, using recording or indicating instruments;
- current density on coupons;
- current flowing on the pipeline, using recording or indicating instruments;
- variations in current output of the suspected source of interference current, and correlation with measurements obtained as above.

The tests should be carried out for a period sufficient for assessing the time dependence of the interference level. Time dependence is dictated by the type of interference phenomenon being investigated.

Interference with other submerged pipelines or installations should be measured after the CP system is energized. These interference tests should be conducted as follows:

- measure the pipeline-to-seawater potential on both the foreign pipeline and the subject pipeline while the relevant sources of CP current that can cause interference are simultaneously interrupted;
- measure the pipeline-to-seawater potential at the foreign pipeline or installation while the CP stations on both the foreign pipeline and the subject pipeline are energized.

The mean change in potential at any part of a foreign pipeline or installation due to interference should not cause the potential on the foreign pipeline to be outside the protection limits given in Clause 6. If interference results in the CP criteria not being met, remedial action shall be taken to reduce the interference to an acceptable level.

F.3.2 General methods for resolving d.c. interference corrosion problems

The following general methods should be considered to resolve interference problems on pipelines or other submerged structures:

- prevention of pick-up or limitation of flow of interfering current through a pipeline;
- removal of detrimental effects of interfering current from a pipeline by means of a metallic conductor between the pipeline and the return (negative) side of the interfering-current source;
- counteraction of the interfering-current effect by means of additional CP on the affected pipeline;
- removal, relocation or readjusting of interfering-current source.

F.4 Interference from alternating current

High voltage a.c. sources, such as power cables and pipeline electrical-resistance heating systems, can result in a.c. interference on the pipeline. The magnitude of this interference depends on the

- proximity of the a.c. source,
- a.c. voltage level,
- a.c. current level,
- number and location of galvanic anodes,
- pipeline coating quality, and
- conductivity of the steel and the seawater.

A.C. interference on pipelines, although rare on offshore pipelines, can cause safety and corrosion issues if not mitigated effectively.

Annex G
(informative)

Pipeline design for CP

G.1 General

This annex covers design and installation features which should be addressed when specifying or designing external corrosion-control systems for offshore pipelines and pipeline risers. It includes specific recommendations for pipelines and risers of various types and installed by different methods.

Pipelines and risers can be addressed as separate entities due to the differences in environmental exposure. The pipeline is normally fully submerged and/or buried in the seabed, whereas the riser may have sections that are buried, submerged, and exposed to tidal, splash and atmospheric zones.

G.2 Pipeline installation methods

G.2.1 General

Water depth, length and diameter of the pipeline, geographic location and economics are the main factors that drive selection of the pipeline installation method. The method selected should be contained in the CP methodology. The installation method should not damage external protective coatings or CP hardware. The installation of a corrosion-control system completed on the lay barge should not adversely affect pipeline installation rate.

G.2.2 S-lay

Galvanic anodes can be pre-installed onto the individual pipe lengths onshore, or attached offshore if this does not affect the pipe lay rate. The anodes or anode connection wires should not be damaged as the pipe moves across the stinger. The selection of field joint coatings, installed offshore after successive pipe lengths are welded together, and coating breakdown factors (see 7.5) should take into consideration the achievable field-joint coating quality.

The most common installation method is for pipe lengths to be joined together, usually by welding, on the pipe lay vessel just prior to installation. The pipe is then fed horizontally from the back of the pipe lay vessel over a stinger as the lay vessel moves forward, the pipeline adopting an S-shape between the seabed and the vessel as it is progressively laid along the seabed. The quality of the field joint coating can be a large factor in the overall initial damage to pipeline coating.

G.2.3 J-lay

The J-lay method is commonly used in deeper waters.

This method involves deployment of the pipe vertically from a J-lay frame, usually located at the rear of the pipe lay vessel. In this method the pipe is subjected to high levels of tension. Prior to the lay, pipeline subsections (usually as quadruple joints) are formed on the deck of the pipe lay vessel and then raised up vertically within the J-lay frame. Special J-lay collars are welded to the pipe at intervals and used to enable the lay vessel to support the weight of the pipe as it is lowered vertically from the lay vessel.

These collars, which often serve also as pipeline-buckle arresters, can be used as galvanic anode installation sites. Bracelet anodes can be pre-installed onshore or can be installed on the quadruple joints offshore. Field joint coatings can be applied to the quadruple joints on the deck of the vessel, but the final “tie-ins” should be applied while the pipe is in a vertical aspect in the J-lay frame.

G.2.4 Reel lay

With the reel-lay method, the individual pipe lengths are pre-welded onshore into long sections. The field joints are coated onshore and the pipe is then reeled up onto a large spool on the pipe lay vessel.

Spacer pads should be deployed between the pipe coils on the reel to minimize coating damage due to pipe-to-pipe contact. Bracelet anodes should not be installed onshore, due to the high stresses introduced in the pipe during the reeling process.

During pipe lay, the pipe is unreeled while being held in tension and deployed, usually over a stinger, in an S-lay configuration. The pipe passes through a series of rollers on the pipe lay vessel which serve to straighten the pipe coming off the reel. A major advantage of this pipe lay method is the speed at which the pipeline can be installed.

Anode installation, which is accomplished on the lay vessel as the pipe is unreeled, should not adversely affect the pipeline installation process. Bracelet anodes and/or anode connection details should be robust enough to withstand the forces exerted on the pipe as it goes over the stinger.

G.2.5 Bottom-tow installation

This method of pipeline installation is only relevant for short pipelines of the order of a few kilometres in length. The pipeline is completely prefabricated onshore at a coastal site (including field-joint coating and galvanic anode installation). The pipeline is then towed out from the coastal site and along the seabed to the installation site.

Abrasion-resistant coatings for the pipe and the field joints should be used, and special precautions taken in the design of anodes. The anode attachment details should provide mechanical stability, reduced drag resistance and minimal snagging risks.

G.2.6 Controlled-depth tow

This method eliminates most of the concerns associated with bottom-tow installation, but the anode weight and distribution shall be taken into account in the buoyancy calculations.

The control-depth tow method is similar to the bottom-tow method, except that the pipeline is rendered buoyant, usually by dewatering and sealing the pipe and adding temporary buoyancy modules at intervals. Flexible weights (usually chains), hung from the pipeline at intervals, offset this buoyancy and allow the pipeline to float at a controlled depth above the seabed suspended between two vessels. The pipeline is towed to the desired location and lowered into place.

G.3 Offshore pipeline and riser types

G.3.1 Pipelines

G.3.1.1 Conventional pipelines

Conventional pipelines can be installed with or without concrete weight coating. They are either buried, open-trenched, or laid on the seabed. They are usually protected with galvanic bracelet anodes, remote galvanic anodes or impressed-current systems, the latter being located at one or both ends of the pipeline.

G.3.1.2 Thermally insulated pipelines

Thermal insulation can be required to prevent the temperature of the pipeline contents from falling below the point at which hydrates or paraffins can form and restrict fluid flow. There are two main types of pipeline thermal-insulation system: either several millimetres of a thick robust thermally insulating coating applied directly onto the pipeline externals, or a pipe-in-pipe system, in which the annular space between the inner and outer pipe is filled with an insulating material. In the pipe-in-pipe system, the outer pipe is fully sealed to ensure that the insulation remains dry. Externally applied thermally insulating coatings are usually polypropylene- or polyurethane-based. Acceptably low heat transfer properties can be achieved by utilizing either syntactic or foamed formulations, or layers of both.

Different CP arrangements can include

- bracelet anodes directly connected to the pipeline,
- bracelet anodes clamped around the outside of the insulating coating with cable connections through the insulation to the steel,
- galvanic anodes installed remotely from the pipeline,
- an impressed-current system,
- thermally sprayed aluminium applied under the insulation.

Bracelet anodes directly attached to the pipe can provide a heat sink and reduce the overall effectiveness of the insulation system. The effects of elevated operating temperature shall be considered in the CP design.

For bracelet anodes clamped around the outside of the coating with cable connections through the insulation to the steel, there is risk of the anodes being moved during the laying process. In such cases, the use of anode-to-insulation transition tapers and disproportionately long connection cables should be considered. Four cables, two for each half-bracelet with the leads attached in longitudinally opposite directions, should be used for such electrical connections. Increased risk to the integrity of the insulation at cable penetrations should be considered.

G.3.1.3 Pipe-in-pipe systems

For pipe-in-pipe systems, thermally insulating materials with much lower thermal conductivities and poorer resistance to water ingress compared to externally applied thermal-insulation systems are used. A protective coating should be applied to the inner pipe before assembly in order to protect the pipe should water enter the outer pipe at some time in the life of the pipeline.

The external surface of the outer pipe should be treated for corrosion protection just as a conventional offshore pipeline.

G.3.1.4 Pipeline bundles

These systems comprise a number of small-diameter pipelines bundled together, often including electrical cables, and installed by the tow method. Dielectric spacers should be provided between the lines in the bundle. These spacers should not adversely affect the spread of protection or inflict damage on the pipe coating systems during construction or bundle installation.

Locating all of the anodes on one pipeline for the protection of all pipelines in the entire bundle may be considered. If this is the case, adequately spaced interpipeline electrical bonds shall be provided to ensure adequate electrical continuity on every pipeline.

G.3.1.5 Flexible pipelines

Flexible pipelines are often deployed as short tie-ins between subsea assemblies and conventional pipelines. If they are entirely of metallic construction, electrical continuity between the flexible pipeline, the conventional pipeline systems and the subsea assemblies should be ensured.

For flexible pipeline systems comprised of concentric non-metallic and metallic sheaths with a thick outer non-metallic layer which run between the metallic couplings or joints, anodes should be located at the metallic couplings or joints.

G.3.2 Risers

G.3.2.1 Standard fixed (static) risers

This type of riser can be connected to the end of the pipeline via a spool piece, with flanged joints at either end. It is usually clamped to the host structure at various elevations. Galvanic anodes may be installed on the riser, or CP provided from the structure or the pipeline.

If electrical isolation of the riser and pipeline from the structure is required, then all of the riser clamps shall be fitted with a dielectric liner of neoprene rubber or similar material. This can be installed at either the pipe-to-clamp interface or the clamp-to-structure interface. If the clamp is electrically isolated from both the riser and the structure, dedicated anodes should be installed on the clamps.

If an isolating flange or joint is installed at the riser, test leads should be provided from either side of the joint, terminating in a weatherproof test box located at an accessible site.

G.3.2.2 Pull tubes (J-tubes)

On fixed and floating offshore platforms in deep water, pre-installed J-tubes can be used to facilitate riser installation. J-tubes are used for pulling the riser into the platform and for mechanical protection of the pipeline risers during the lifespan of the platform. After pull-in and during subsequent operation, it is difficult to verify the effectiveness of the corrosion protection of the section of the pipeline riser within the J-tube.

Risers installed in this way should be protected with a high-quality, abrasion-resistant coating system to minimize damage to the coating during pull-in. However, adequate allowance should be made for the likelihood of coating damage when determining the CP requirements for the section of the riser within the J-tube. Other corrosion-control measures, such as inhibition, may be applicable for the annular space between the J-tube and the riser.

If galvanic anodes are used to protect the lower internals of the J-tube, the anodes should be mounted at the 6 o'clock position in order not to interfere with the riser during pull-in operation.

G.3.2.3 Steel catenary risers

Steel catenary risers can be used to connect deepwater pipelines to floating production units. The riser is suspended from the production platform near the surface of the water and hangs from the platform with a pre-determined catenary to a point on the seabed where it touches the seabed. These riser systems can be subject to very high stresses in service. Certain components of the support detail can be fabricated from high-strength materials that are sensitive to CP under these highly stressed conditions. The extent of this sensitivity should be considered (see Table 1). Identification of any risks may preclude attaching anodes directly to the catenary section of the riser. Anodes may be located on the static section of the riser or the host structure above and/or on the pipeline below, in order to protect the catenary section. Potential attenuation modelling may be used to determine the spread of protection down the riser from different anode configurations and/or locations.

Steel catenary risers are often fitted with strakes to reduce the effects of vortex-induced vibration. CP may not be fully effective beneath the strakes, and this should be recognized in the selection of a suitable protective coating for these areas.

G.3.2.4 Flexible risers

These are normally of the same construction as the flexible pipe previously discussed (see G.3.1.5), and the same considerations apply.

G.4 Burial and stabilization

G.4.1 General

The decision whether or not to bury an offshore pipeline and/or how to stabilize it on the seabed is determined based on the fluid being conveyed, the operating temperature and any local regulations. The extent of burial and any measures used to stabilize the pipeline should be considered in the design and effectiveness of the CP system.

G.4.2 Burial conditions

G.4.2.1 Exposed

In this condition, the pipeline is initially laid on the seabed where it is exposed mainly to seawater and can be susceptible to in-service damage to coatings and anodes. This should be considered in the CP design, particularly in shallow waters in busy shipping areas.

If, for design purposes, there is no seabed movement in the area, the pipeline and anodes should both be considered as being 100 % exposed. If during the life of the pipeline there is evidence of seabed movement such that the anodes could be covered by sediment (and the pipeline remaining exposed or also becoming buried), this should be considered in the CP system design.

NOTE The worst case for CP design is pipeline which is 100 % exposed with the anodes 100 % buried; the best case design is pipeline which is 100 % buried and the anodes 100 % exposed. In partial-burial situations, the actual case lies somewhere between these extremes.

G.4.2.2 Open-trenched

In this condition, the pipe is laid into a pre-excavated trench and no attempt is made to bury it. The assumption is that this will protect the pipeline from mechanical damage, as the trench usually self-backfills with time. Such pipelines are normally given the same consideration as fully buried lines when designing the CP system, but this should be assessed taking into consideration local field experience with self-burial.

G.4.2.3 Trenched and filled

In this condition, the pipeline is intentionally buried, usually with the aid of a towed burial sled that buries and backfills the line in a single pass. If this method is to be used, it should be ensured that anodes do not provide a snagging point for towed-sled apparatus which normally straddles and moves along the pipeline. The use of fully moulded tapered anodes or those fitted with reinforced cast-on polyurethane tapers, to smooth the cross-sectional transition, are measures that should be considered in this case.

If there is likelihood of a buried pipeline becoming exposed, more anodes can be required. This should be considered in the design and, if recognized as a risk, the pipeline should be designed as an exposed pipeline.

G.4.3 Stabilization methods

G.4.3.1 Unstabilized pipeline

For pipelines without concrete coating, anodes should be installed on top of the corrosion coating. The method of anode attachment shall be sufficiently robust to withstand the pipe-laying process. Methods to avoid anode slippage can include the use of anodes with a tapered shape or with tapered end fittings on either side of the anode, as required for the pipe-laying process.

G.4.3.2 Weight-coated pipeline

The application of a reinforced concrete coating over the corrosion coating is standard procedure for some large-diameter subsea pipelines. The concrete reduces buoyancy and provides mechanical protection to the pipeline additional to that which can be gained by partial or total burial.

During galvanic anode installation, it should be ensured that the steel reinforcement in the concrete does not come into electrical contact with either the pipeline itself or the bracelet anodes, to avoid shielding of the protective current to the pipeline. Electrical continuity between the reinforcement and the pipe and/or the anodes can also impose a higher current demand on the pipeline anodes than allowed for in the CP design. If the weight-coated line is to be installed by the S-lay or J-lay method, the anodes should be inset within, or flush with, the concrete weight coating. Alternatively, the use of tapered anodes or reinforcing cast-on polyurethane tapers may be considered in order to smooth the cross-sectional transition and thus minimize damage to the anodes during the laying operation.

G.4.3.3 Rock dumping

Rock dumping involves the covering of an unburied pipeline with rocks. If this is the proposed method of stabilization, additional coating damage and loss of anodes can be expected, and the CP design should reflect this. The use of pre-fabricated flexible concrete mats is sometimes used instead of rock dumping to stabilize a pipeline. Some newer designs provide non-metallic soft coverings over the concrete to further reduce the risk of coating damage during installation. The mats can be lowered gently onto the pipeline in a controlled manner.

G.4.3.4 Pipeline anchors

Various types of pipeline anchor can be used in areas of high current flow, such as near large estuaries, and in certain arctic regions. The impact of these anchors on the CP design should be carefully evaluated, especially if they include the use of steel pilings. If an excessive current drain to the anchors is predicted, the anchors should be provided with a CP system independent of the pipeline system.

G.5 Pipeline crossings and subsea connections

G.5.1 Crossings

Interference can occur between the CP systems at subsea pipeline crossings. If both pipelines are protected by galvanic anodes, it is normal to provide separation between the two pipelines at the crossing point.

A separation of 0,3 m is normally adequate, but smaller separation distances may be acceptable if it can be demonstrated that CP interference between the lines is insignificant.

The risk of seabed or pipe movement with time should be compensated for by the introduction of a physical separation barrier at the crossing point. The barrier can be a concrete mat, a rubber mat or sandbags.

G.5.2 Subsea connections

At subsea connections between two pipeline systems, it should be ensured that no significant interference occurs between the CP systems on the two pipelines.

If the two systems are directly connected, all the relevant details of the CP systems should be considered, such that neither CP system causes an undue drain on the other CP system.

If the two systems are electrically isolated, the condition of the isolation joint and of the anodes close to the isolation joint should be periodically verified. The possibility of interference between the two systems should be considered, e.g. in the case of one of the lines having an impressed-current system and the other line having a galvanic system.

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