PD 8010-5:2013

BSI Standards Publication

PUBLISHED DOCUMENT

Pipeline systems –

Part 5: Subsea pipelines – Guide to operational practice

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Published by BSI Standards Limited 2013

ISBN 978 0 580 77047 0

ICS 23.040.10; 75.200

The following BSI references relate to the work on this document:
Committee reference PSE/17/2
Draft for comment 13/30274989 DC

Publication history

First published September 2013

Amendments issued since publication

Date	Text affected

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Foreword

Publishing information

This part of PD 8010 is published by BSI Standards Limited, under licence from The British Standards Institution, and came into effect on 30 September 2013. It was prepared by Subcommittee PSE/17/2, *Pipeline transportation systems*, under the authority of Technical Committee PSE/17, *Materials and equipment for petroleum*. A list of organizations represented on these committees can be obtained on request to their secretary.

Relationship with other publications

PD 8010-5 is a new part of the PD 8010 series. The series comprises:

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

This part of PD 8010 is intended to be read in conjunction with PD 8010-2 and PD 8010-4:2012.

Information about this document

This part of PD 8010 was initially drafted using Pipeline Users Group documents as a basis, with their kind permission.

As an industry develops, the practices and procedures it adopts improve so that the way business is conducted within that industry improves with that development. In the oil and gas offshore industry, some subsea assets have been in operation in the North Sea for several decades, during which time lessons have been learned and operational practice improved. This part of PD 8010 presents a number of operational practices that have been established as a result of these developments.

It is anticipated that operational pipeline engineers will use this part of PD 8010 on a regular basis; pipeline design engineers will take cognisance of it in the design of pipeline systems; and third-party providers of equipment and services will be able to align the products and services they provide with the guidance and recommendations given.

Use of this document

As a guide, this part of PD 8010 takes the form of guidance and recommendations. It should not be quoted as if it were a specification or a code of practice and claims of compliance cannot be made to it.

It has been assumed in the preparation of this part of PD 8010 that the execution of its guidance will be entrusted to appropriately qualified and experienced people, for whose use it has been produced.

BSI permits the reproduction of Figure B.1, Figure D.1, Figure G.1, Figure H.1 and Table E.1. This reproduction is permitted only where it is necessary for the user to use the sample pro-formas given in the figures and table during each application of the standard.

Presentational conventions

The guidance in this part of PD 8010 is presented in roman (i.e. upright) type. Any recommendations are expressed in sentences in which the principal auxiliary verb is "should".

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

Contractual and legal considerations

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

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

1 Scope

This part of PD 8010 gives guidance on the following aspects of offshore subsea system operational practice:

- determining the requirement for a subsea isolation valve (SSIV);
- selection and use of high pressure in-line isolation plugs;
- pipeline integrity data exchange;
- caisson and J-tube integrity management;
- emergency shutdown valve (ESDV) testing;
- operational testing of pig launchers and receivers.

2 Normative references

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

PD 8010-2, *Code of practice for pipelines – Part 2: Subsea pipelines*

PD 8010-4:2012, *Pipeline systems – Part 4: Steel pipelines on land and subsea pipelines – Code of practice for integrity management*

3 Terms, definitions, symbols and abbreviations

3.1 Terms and definitions

For the purposes of this part of PD 8010, the terms and definitions given in PD 8010-2, PD 8010-4:2012 and the following apply.

3.1.1 annulus

void between a caisson/J-tube inner wall and the outer wall of components (e.g. one or more flexible or rigid risers, J-tubes, umbilicals) installed within the caisson/J-tube

3.1.2 bellmouth

short conical extension piece at the end of a J-tube, the purpose of which is to aid insertion of risers and umbilicals into the J-tube and minimize the risk of damage during installation, and to provide a similar mechanical protection during operation by maintaining a filleted contact and supporting surface at the entry point

3.1.3 caisson

prefabricated tubular assembly, containing one or more smaller diameter tubular components (usually rigid risers and J-tubes) which pass through the top and bottom sealing bulkheads

NOTE A caisson can be in multiple components, e.g. upper and lower caisson sections.

3.1.4 closed-in tubing head pressure

pressure at the bottom of a well, caused by formation fluids at the bottom of the well, when the surface valves on the top of the well are completely closed

NOTE This is also referred to as shut-in bottomhole pressure.

3.1.5 failure

event, state or condition of not meeting a desirable or intended objective

3.1.6 flowline
pipeline between two subsea facilities (e.g. wellhead and manifold) or between a subsea facility and an offshore installation

3.1.7 installation duty holder
person appointed by the licensee to manage and control, directly or by any other person, the execution of the main functions of a production installation

3.1.8 integrity strategy
document typically supported by a relevant risk assessment, describing appropriate mitigation measures that are put in place to ensure that deterioration processes are controlled and/or monitored

NOTE It is common that a separate integrity strategy is prepared for different disciplines or areas (e.g. external integrity, internal integrity, functional integrity).

3.1.9 threat
act, condition or event that could result in degradation of equipment or otherwise detrimental effect on integrity and ultimately to failure

NOTE This is also known as a hazard.

3.1.10 tidal zone
area inside an annulus affected by tidal water movement

NOTE There are subtle differences between the environment in the annulus tidal zone and the external splash zone, but the primary risk remains corrosion resulting from the changing wet and dry environment, aggravated by the very limited accessibility and inspectability.

3.2 Symbols

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

B	benefit of an SSIV
C	cost of an SSIV
D_{i}	pipeline internal diameter
F_{D}	frequency of demand
f_{GD}	factor of gross disproportionality
f_i	frequency of incident type i
i	incident type
L	pipeline length
n_i	number of fatalities due to incident type i
P	pipeline pressure
P_1	pressure behind ESDV at start of test, in bar [1)]
P_2	pressure behind ESDV at end of test, in bar
P^*	maximum acceptable probability of failure (Poisson distribution)
$P_{\mathrm{F}a}$	maximum acceptable probability of failure
$P_{\mathrm{F}m}$	probability of failure occurrence for given failure mode m
PLL_i	initial PLL with no SSIV installed
PLL_f	final PLL with an SSIV installed

1) 1 bar = 10^5 N/m^2 = 100 kPa.

P_T	pressure in main pipeline during test, in bar
T	design life of an installation
T_{rem}	remaining life of an existing installation
t	time for pressure to rise from P_1 to P_2
V	volume of piping behind ESDV, in metres cubed (m^3)
Z	test interval
λ_m	failure rate for given failure mode m

3.3 Abbreviations

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

ALARP	as low as reasonably practicable
CITHP	closed-in tubing head pressure
CP	cathodic protection
ESCI	equivalent social cost index
ESDV	emergency shutdown valve
FA	number of failures averted
FPSO	floating production, storage and offloading (vessel)
HAZID	hazard identification
HAZOP	hazardous operations
ICAF	implied cost of averting a statistical fatality
ID	internal diameter
NDT	non-destructive testing
NOP	normal operating pressure
OD	outer diameter
PLL	potential loss of life
PMR	planned maintenance routine
QRA	quantitative risk assessment
ROV	remotely operated vehicle
SSIV	subsea isolation valve
VIV	vortex-induced vibration
VSL	value of a statistical life
WT	wall thickness

4 Determining the requirement for a subsea isolation valve (SSIV)

*COMMENTARY ON CLAUSE **4***

This clause reflects operational practice regarding the North Sea hydrocarbon infrastructure. It is assumed that it would be largely applicable in any offshore hydrocarbon domain.

The clause offers guidance to pipeline engineers on how the decision regarding the requirement for an SSIV is made and, in the same light, regarding whether, later in field life, it might no longer be required. A key element in the decision is quantitative risk assessment (QRA), and this clause explains how the results of a QRA are used (but not how one is carried out).

It is important to recognize that the question as to whether an SSIV is required cannot be resolved by a simple rule-based approach, as is illustrated in Annex A.

4.1 Reasons for installing an SSIV

4.1.1 General

A disproportionate number of incidents to pipelines occur close to installations. A subsea isolation valve (SSIV) is used to isolate a platform or other installation from the full inventory of a pipeline in the event of a rupture of that pipeline close to that installation, i.e. it prevents the inventory of hydrocarbons from feeding, and thus escalating, a hydrocarbon release incident that has the potential to adversely impact the safety of the installation. An SSIV is assumed to be a safety device, i.e. it is installed to protect life. It cannot prevent the initial release from an incident, but it stifles the bulk flow from the pipeline, preventing escalation.

Where a hydrocarbon-carrying pipeline with a connection to an offshore installation is involved, the installation of an SSIV is beneficial. However, the benefits and disadvantages need to be weighed against each other as part of the decision-making process (see **4.2**).

4.1.2 Causes of hydrocarbon releases

On a typical subsea pipeline, the length of pipeline close to an installation (typically 500 m on the seabed plus the length of the riser) constitutes a very small percentage of its total length. Across the North Sea, more incidents tend to occur near the installation than mid-length.

Statistics given in PARLOC 2001 [1] suggest that incidents within 500 m of an installation might be slightly more likely to involve loss of containment. Taking into account the high level causes of failure, it is possible to see why the majority of incidents occur close to installations:

- **Internal corrosion**. Flow at the arrival end is at its coolest, so water drop-out or condensation might be more likely than at the entry end. Reduction of hydrostatic head in the riser can lead to gases coming out of solution. Slugging might occur in the riser. Internal corrosion might be more likely in the platform zone.
- **External corrosion**. The splash zone, which includes the tidal range and the area above it that is wetted by waves and wind-driven spray, is the most vulnerable part of any pipeline system to external corrosion. Tidal zones within J-tube annuli are also at risk from corrosion, and difficult to inspect.
- **Impact damage**. Damage can arise from failed lifts (dropped objects), structural failures (e.g. water-winning caissons falling off), or lateral impacts. The first two are specifically associated with platforms (few lifts are carried out in the vicinity of the mid-lengths of pipelines). Lateral impacts include

vessel impacts (see below) and impacts on the seabed. Concentrated vessel activity means greater likelihood of anchor damage, although there is a general expectation that fishing will not be permitted within 500 m of an installation.

- **Vessel impacts**. These are a special case of lateral impact because, occurring close to sea level, which is also the most vulnerable zone for external corrosion, they can have catastrophic consequences for both the platform and the impacting vessel.
- **Structural modes**. Expansion spools can become buried, either by drilling mud or by deposition caused by the platform hydrodynamics. Alternatively, scour can lead to long spans in riser base tie-in spools. Both mechanisms are known to have led to failure. Excessive riser clamp/guide spacing can lead to failures due to wave loading or vortex-induced vibration (VIV)-induced fatigue.
- **Failures at fittings**. Most fittings (flanges, valves, etc.) are found within 500 m of an installation.

An installation can be a fixed platform (steel jacket or concrete caisson type) or a floating production system. In the latter case, the risers are flexible, except in deep water where steel catenary risers may be used. Flexible risers may also be installed on fixed platforms. Flexible risers exhibit a number of unique failure modes, but a major cause of failure is corrosion of armour wires following external sheath damage that allows seawater ingress.

NOTE For more information on failure modes of flexible risers, refer to State of the Art Flexible Riser Integrity Issues, Study Report (2001); prepared by MCS International for UKOOA, Doc No 2-1-4-181/SR01, Rev 04 [2].

4.1.3 The nature of hydrocarbon releases

*COMMENTARY ON **4.1.3***

If an incident leads to loss of containment outboard of the riser emergency shutdown valve (ESDV), then the full inventory of the pipeline could escape, at least until the internal (pipeline) and external (hydrostatic) pressures become balanced. This subclause examines how this could occur.

4.1.3.1 Sub-surface releases

In the case of a gas pipeline, or a line carrying a volatile product, the gas exits the pipeline and rises to the surface in a plume, entraining water and spreading as it ascends. Erosion is likely to enlarge a pinhole leak rapidly in such a scenario, so that large volumes of gas will quickly reach the surface. An initial effect of this might be a reduction in the buoyancy of any vessels in the zone, which could be over 100 m in diameter, depending upon the flow rate and pressure of the gas, and the water depth. A smaller vessel might sink.

On attaining the surface, the gas forms a cloud, which might be toxic as well as flammable. This might ignite if a suitable heat source is in the vicinity, or it might move downwind. If this takes it towards an installation, exposed crew could suffer asphyxiation or toxic effects, or the gas could ignite.

Meanwhile, lighter liquid fractions are carried to the surface where they form pools. If the gas ignites, these pools are likely to be ignited also. Whether or not they are ignited, they pose a hazard to any crew who might abandon a vessel that loses buoyancy. If extensive, they could impede access to the installation to fight fires or evacuate personnel.

In the case of an oil pipeline, all but the heaviest product rises to the surface and forms a slick. This might not threaten human life, but it harms animal life and causes environmental damage.

4.1.3.2 Above-surface releases

In the case of a failure in a gas riser above the sea surface, the gas could ignite, in which case the release momentum will lead to a jet fire. A jet fire can play on other parts of the structure and either cause subsequent fires, or significantly weaken structural members. If the gas does not ignite, the threat of asphyxiation or, in some cases, toxicity remains.

Liquid riser releases can collect on lower decks but are more likely to fall to the sea surface. If ignited, they can form pool fires; if not, they cause environmental damage, and obstruct access to the installation (for fire-fighting or evacuation).

4.1.3.3 Prevention of escalation

An SSIV does not prevent the initial loss of hydrocarbons, so gas clouds or jet fires are likely to occur. By minimizing the feed-in from the main pipeline, however, an SSIV is expected to prevent any escalation of the incident: a jet fire is unlikely to be sustained for long enough to start secondary fires or weaken the structure. If a gas cloud ignites, it will be short-lived.

4.1.4 Location of an SSIV

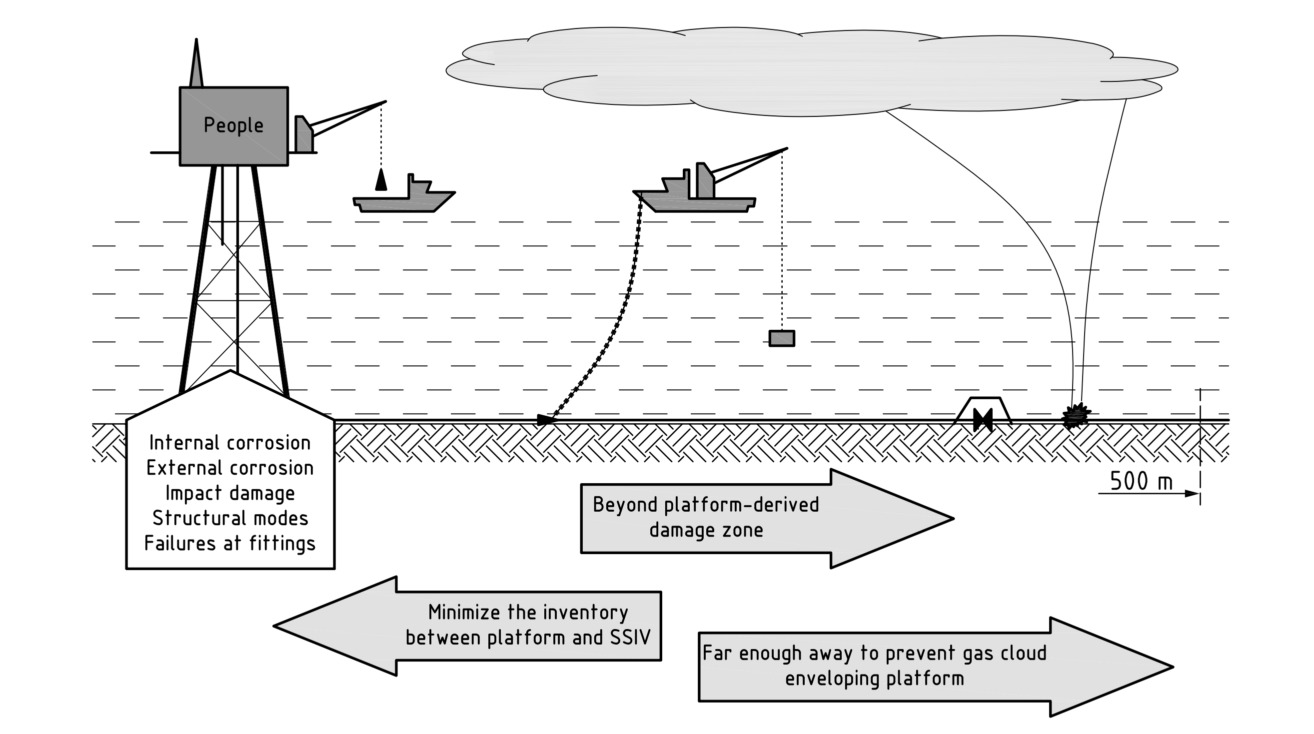
The location of an SSIV is of great importance. Poorly positioned SSIVs might have negligible benefit to the safety of an installation. There are four main factors.

- A primary aim is to minimize the inventory that can feed a loss of hydrocarbons incident outboard of the riser ESDV: this implies that it should be installed close to the riser base.
- Conversely, it has been shown that a significant proportion of loss of containment incidents occur in close proximity to installations: this implies that it should be installed at some distance from the installation, at least beyond the range of the greatest vessel activity.
- Another consideration is the potential gas cloud: ideally, if loss of containment arises following an incident just outboard of the SSIV itself (i.e. fed by the full inventory of the pipeline), the location of the SSIV should be far enough away to maximize the chance of dissipation of the gas cloud before it reaches the installation.
- The SSIV gains some measure of protection itself if it is within 500 m of an installation, from which fishing and merchant vessels are excluded under the Petroleum Act 1987 [3].

These points are illustrated in Figure 1.

The consequence analysis and QRA described in **4.2** should be used in determining the optimum position for the SSIV.

Figure 1 **Influences on the location of an SSIV**



4.2 Decision-making process

*COMMENTARY ON **4.2***

The basis of the decision-making process is to determine the difference between the potential loss of life (PLL) with an SSIV and the PLL without an SSIV. If the PLL without an SSIV is unacceptable and there is a beneficial reduction in PLL with an SSIV, then the decision is clear. Where the reduction in PLL with an SSIV is marginal then a cost-benefit analysis can contribute to the decision-making process.

4.2.1 Quantitative risk assessment

*COMMENTARY ON **4.2.1***

A key element in determining the requirement for an SSIV is to carry out a quantitative risk assessment (QRA), and this is especially true where an SSIV is in place and there is a need to assess whether it is still required. The QRA for an installation takes account of all possible hazards, not just hydrocarbon releases, which are identified by a hazard identification (HAZID) exercise as applying in any part of the installation. This subclause looks only at those aspects of the QRA that are pertinent to the SSIV decision.

HAZID is a process of identifying and recording hazards and as such is a common technique supporting qualitative risk assessments. HAZIDs are normally carried out by a team of competent persons from a mixture of disciplines (e.g. subsea, process, corrosion, structural, safety) and are led by a person who is experienced in the HAZID technique. It is a common practice to break down the subject (i.e. the pipeline) into segments and consider individual segments against a pre-prepared checklist of hazards. Where it is agreed that a hazard exists in a particular segment, the risk presented by the hazard is considered, and all possible means of either eliminating the hazard or controlling the risk and/or the necessity for further study are noted on a HAZID worksheet. Actions are assigned to either discipline groups or individuals to ensure the mitigating control, or further study is completed.

The first step in a QRA is to carry out a detailed fire risk analysis for the installation, which involves modelling hydrocarbon releases from all areas. All isolatable segments should be identified (from the HAZID), the inventory included in each segment should be calculated, and assumptions should be made concerning the likely size of breach in each area (a range of sizes should be investigated – typically small, medium and large). The isolatable segments are the riser, tie-in spools and pipeline, constrained or not by an SSIV. Consequence modelling should also include failure of the riser-top ESDV to close, which will extend the isolatable segment to the next barrier within the topsides pipework.

NOTE 1 The probabilities of hydrocarbon release, size of hole and ignition, and of safety systems (e.g. deluge systems) containing different types of fire, can all be derived from published data: for instance, PARLOC 2001 [1] is a source of data on hydrocarbon releases from pipelines and risers.

For jet fires, the modelling should typically define:

a) initial flame length;

b) flame length after certain specified periods;

c) distance from the flame centre to specified heat flux levels;

d) duration of the fire.

For pool fires, diameters and thermal radiation contours should be modelled. These have probabilities associated with them, of a given pool fire of a given radius possessing a given thermal radiation contour.

These consequence models, for a range of hole sizes, should then be used to determine the likelihood of escalation, e.g. other critical elements of the installation (such as key structural components) failing, or other parts of the plant failing, resulting in further emissions which could then ignite. With regard to SSIVs, items b) to d) above can be defined both without and with an SSIV, as can the diameter of a pool fire. Thus the benefit of the SSIV in terms of preventing escalation can be ascertained.

The second step in a QRA is to convert the fire modelling data into numbers of potential fatalities and injuries resulting from fires modelled both with and without an SSIV. Some of these will be due to the initial release and direct contact, others will result from escalation over time. Various studies of installations provide the probability of varying numbers of people being in various locations at different times, although any SSIV study should ideally be conducted using installation-specific information.

By combining the probability of a given fire event with the probability of people being in its location, the probability of fatalities and injuries can be calculated. Investigations of escalation should look at the probability of impairment of the temporary refuge, and combine this with the probable numbers in the temporary refuge to calculate fatalities and injuries there. The inclusion of an SSIV minimizes the escalation, so the benefit can be defined as the prevention of fatalities and injuries.

One possible output from a QRA is the calculation of a potential loss of life (PLL) value:

$$\mathrm{PLL} = \sum_{i=1}^{n} f_i n_i \qquad (1)$$

where:

f_i is the frequency of incident type *i;*

n_i is the number of fatalities due to incident type *i.*

The value of n_i can be determined by summing, for incident type *i*, the predicted numbers of fatalities for each of the different categories of people on an installation, e.g. those who work only in the temporary refuge, those whose duties take them outside the temporary refuge occasionally, and those who work mostly outside the temporary refuge.

The PLL values, with and without an SSIV in place, can be used, as described in **4.2.2**, to determine whether the installation of an SSIV is justified. The same approach can be used to determine whether an existing SSIV might be locked open.

NOTE 2 An enhancement of the PLL concept is the equivalent social cost index (ESCI) which is almost the same as the PLL except that the n_i term is factored by an aversion index, p, as a means of including the aversion of the public, or a relevant subset of the public, to a particular type of multi-fatality incident (e.g. people generally appear to have a greater aversion to fatalities due to air crashes than they do to fatalities due to car crashes). Thus, as explained in greater detail in the research report Application of QRA in operational safety issues *[4], a PLL is an ESCI with an aversion index of unity.*

4.2.2 Cost-benefit analysis

The detailed fire risk analysis and the QRA can be used to determine, for every relevant type of incident, the PLL value with and without an SSIV installed. The SSIV cannot prevent the initial release and so has no impact on the incident frequencies, but is assumed to prevent escalation and limit the duration of the incident. Thus, it is possible to define the number of fatalities averted (FA) over the lifetime of the installation:

$$\mathrm{FA} = \left(\mathrm{PLL}_i - \mathrm{PLL}_f\right)T \qquad (2)$$

where:

PLL_i is the initial PLL with no SSIV installed;

PLL_f is the final PLL with an SSIV installed;

T is the design life of the installation.

This is the fundamental measure of the benefit of installing an SSIV but, for practical purposes, it has to be converted into cost terms.

One term that can be calculated is the implied cost of avoiding a statistical fatality (ICAF):

$$\mathrm{ICAF} = \frac{C - B}{\mathrm{FA}} \qquad (3)$$

where:

B is the benefit of an SSIV;

C is the cost of an SSIV.

In this case, the cost is that of installing, operating, maintaining and decommissioning (i.e. the full life cost of) the risk reduction measure, in this case an SSIV. Benefit refers to other, non-safety, value that is obtained by the installation (e.g. improved production) but, in the case of an SSIV, there are unlikely to be any such parallel benefits.

Rearranging and substituting results in:

$$C - B = \left(\mathrm{PLL}_i - \mathrm{PLL}_f\right)T \times \mathrm{ICAF} \qquad (4)$$

This ensures that, if there is a benchmark for the cost of avoiding a fatality, it is possible to determine a justifiable cost for an SSIV.

NOTE The ICAF refers to a statistical fatality. Various government and industry bodies in various countries have determined the value of a statistical life (VSL). There are various ways of approaching this (e.g. relating peoples' views on earnings in comparison to the risk associated with different jobs, or simply questioning large numbers of people) and results are somewhat variable. Most major oil and gas operators have their own values for VSL.

Equation (4) could be used for the SSIV decision provided that some factor of gross disproportionality is included:

$$C - B = \left(\mathrm{PLL}_i - \mathrm{PLL}_f\right) T \times f_{\mathrm{GD}} \times \mathrm{VSL} \tag{5}$$

where:

f_{GD} is a factor of gross disproportionality.

The right-hand side of equation (5) can be thought of as the justifiable cost. The purpose of the factor of gross disproportionality (f_{GD}) is to make clear a cost above which an SSIV is not justified. It is suggested here that the value should lie in the range $5 \leq f_{\mathrm{GD}} \leq 10$.

Using equation (5) with these inputs, it is possible to set a simple rule:

$$IF : C \leq (\mathrm{PLL}_i - \mathrm{PLL}_f)T \times f_{\mathrm{GD}} \times \mathrm{VSL} \quad THEN : \text{install SSIV}$$

where the cost includes procurement, installation, maintenance, and decommissioning.

The respective values of PLL are critical in the decision. In the UK, demonstrating risks to be ALARP also requires consideration of industry standards and good practice, and these form part of any SSIV requirement decision, with the starting point being presumption that an SSIV would be good practice. The information flow process involved in the analysis that might justify a decision not to install one is depicted in Figure 2.

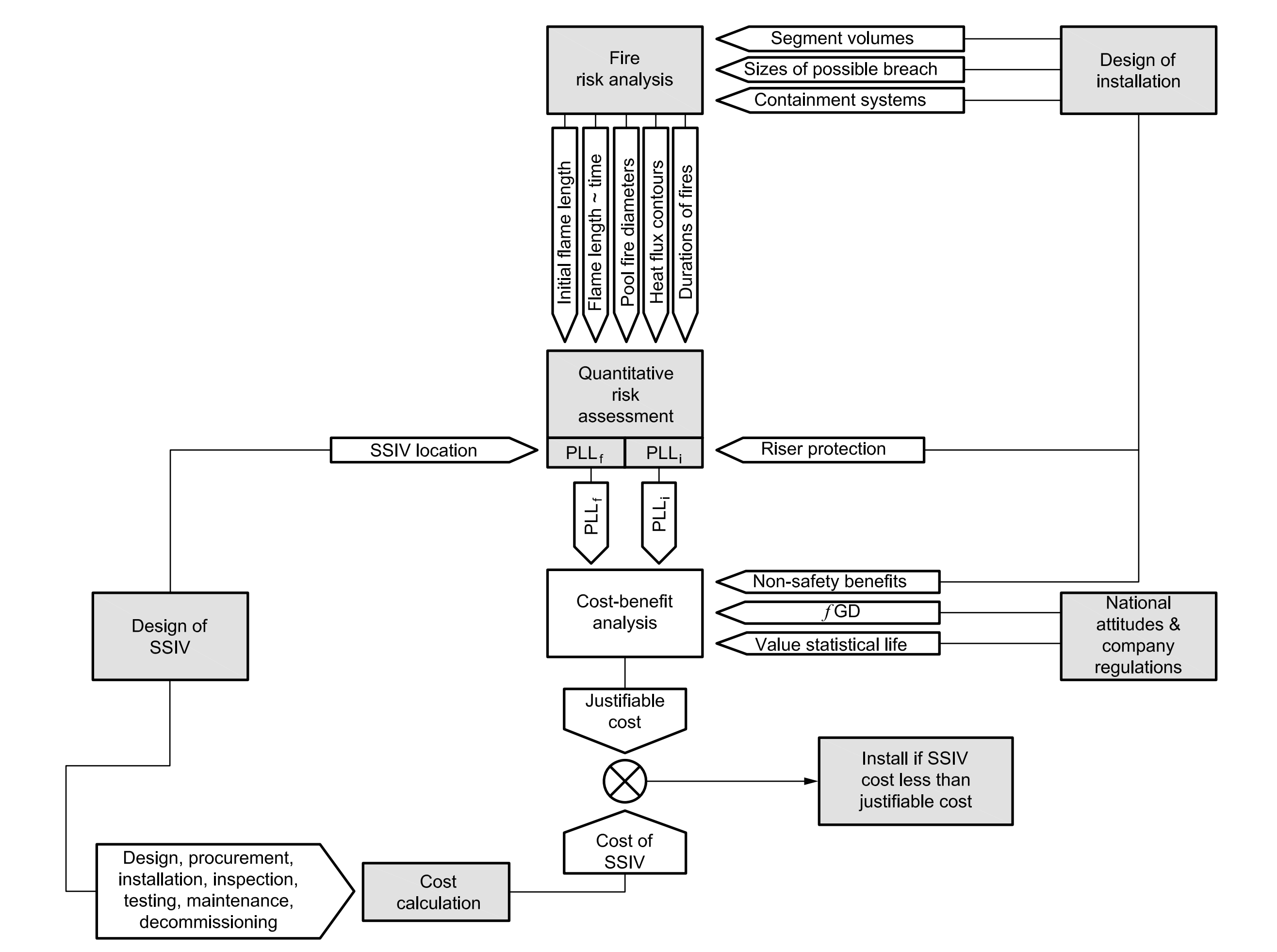
4.2.3 Factors influencing the decision

The high level causes of pipeline failures that occur close to installations are listed in **4.1.2**. If these causes can be controlled so that the probability of failure is minimized, then the value of PLL_i will be reduced. As a result, the term ($\mathrm{PLL}_i - \mathrm{PLL}_f$) will also be reduced and an SSIV might not be required (as is the case at many installations). In general, these controls should be implemented during pipeline design and fabrication so that they are built in and not subject to human error during operation. Examples of controls that may be implemented to reduce the probability of a pipeline incident are given below.

a) **Internal corrosion**. The probability can be reduced during the design and procurement phases by selecting corrosion-resistant materials; avoiding piping designs that encourage water which has separated to be trapped; and, where applicable, installing adequate and reliable dehydration facilities. Pipelines should be designed to be pigged (both for water sweeping, etc., and for inspection). Attention to detail in the design of the chemical injection system can maximize the ability to control corrosion in operation through chemical inhibition. The annulus vents of flexible risers should be properly plumbed in, with provision for monitoring the flow rate and constituents of the gas.

b) **External corrosion**. The probability can be reduced by attention to coating selection and application. Field joint coatings can be a weakness. Where risers move through guides, precautions should be taken to ensure that coatings cannot be damaged. Installation cathodic protection (CP) should be suitable. If riser caissons are installed, provision should be made for monitoring the pressure, and for sampling the environment at intervals. If risers are installed in J-tubes, provision should be made for sampling the water in the annuli and for replenishing the corrosion inhibitor, as required,

Figure 2 **Information flow – The decision whether an SSIV is required**



both at the surface (the tidal zone) and at the bottom (close to the J-tube seal) (see *Guideline on caisson and J-tube Integrity management* [5]). Topsides, attention should be paid to minimizing corrosion under passive fire protection coatings, which should be installed wherever practicable.

c) **Impact damage**. Risers should be installed where they are protected from vessel impacts (well within the jacket structure of fixed platforms, ideally behind legs), and where dropped objects are unlikely.

Flowline tie-ins should be located clear of platform cranes and other likely sources of dropped objects. Flowlines and tie-in spools close to installations should be protected by concrete structures or mattresses.

It should be possible at all times to determine the relative location of the flexible risers to the deck cranes in the case of weather-vaning FPSOs.

d) **Structural modes**. Riser clamp spacings should ensure that environmental loading or VIV cannot lead to failure. Spoilers could be used for VIV protection (taking into account the need for access for inspection). Tie-in expansion spools should not be located near drilling mud discharges, etc. Scour protection should be taken into account. For FPSOs, prevention of failures is part of the detailed design of the flexible riser system (including mid-water arches, tether systems, etc., as applicable) and the mooring system.

e) **Failures at fittings**. The probability can be reduced by attention to the specification of fittings, and to the quality of welding or other connections. Topsides, pipework routes should be selected to minimize escalation.

The list above is not comprehensive, but suggests ways in which PLL_i can be reduced by attention at the design stage. Many of these issues are not, however, within the domain of the pipeline engineer. A number of these causes can be controlled by lifecycle management, but this can be subject to human errors of omission and commission and, as such, might not reduce PLL_i to such an extent.

Many of the controls suggested above would incur additional cost to a project. The cost of procurement and installation of an SSIV might appear cost-effective in comparison. Project teams frequently minimize their costs at the expense of lifecycle costs, although the latter might be far greater and should be used for the comparison. The net present value of the lifecycle costs of the various options might have to be used.

If an SSIV is deemed to be required, then it should be included in the safety case for the installation, and it should be subject to regular testing (see **4.3**).

4.2.4 Existing SSIVs

The guidance in **4.2.3** covers the decision whether to fit an SSIV, but a number of SSIVs are already in service, incurring inspection and maintenance costs, and might no longer be justified. In such cases, QRA becomes the recommended approach to examining this issue and the current requirement for an SSIV may be challenged on one of three grounds:

- the original decision to install an SSIV was not based upon a QRA [2)];
- some of the assumptions in the original QRA are found in service to be clearly incorrect;
- operating conditions have changed since the original QRA was carried out.

In these cases, the challenge should make use of the QRA and cost-benefit equation (5):

$$IF : C > (\mathrm{PLL}_i - \mathrm{PLL}_f)T_{\mathrm{rem}} \times f_{\mathrm{GD}} \times \mathrm{VSL} \quad THEN : \text{consider locking SSIV open}$$

where the cost includes maintaining for the remaining life (T_{rem}) and decommissioning.

Industry practice should also be taken into account in demonstrating that risks are ALARP.

Later in field life:

- it might be possible to show that (PLL_i – PLL_f) has reduced;
- the remaining life (T_{rem}) might be small; and
- it might be argued that the late life value for f_{GD} should be lower;

but the residual lifecycle cost of the SSIV (inspection, maintenance and decommissioning) might also be relatively small, so that the cost of the SSIV is still justified.

On the other hand, if the remaining lifecycle cost exceeds the justifiable cost, then an argument can be made to lock the SSIV open and to cease testing. If the argument is accepted, this should be recorded in the safety case for the installation. The information flow for this scenario (taken from Figure 2, with alterations in bold grey type) is shown in Figure 3.

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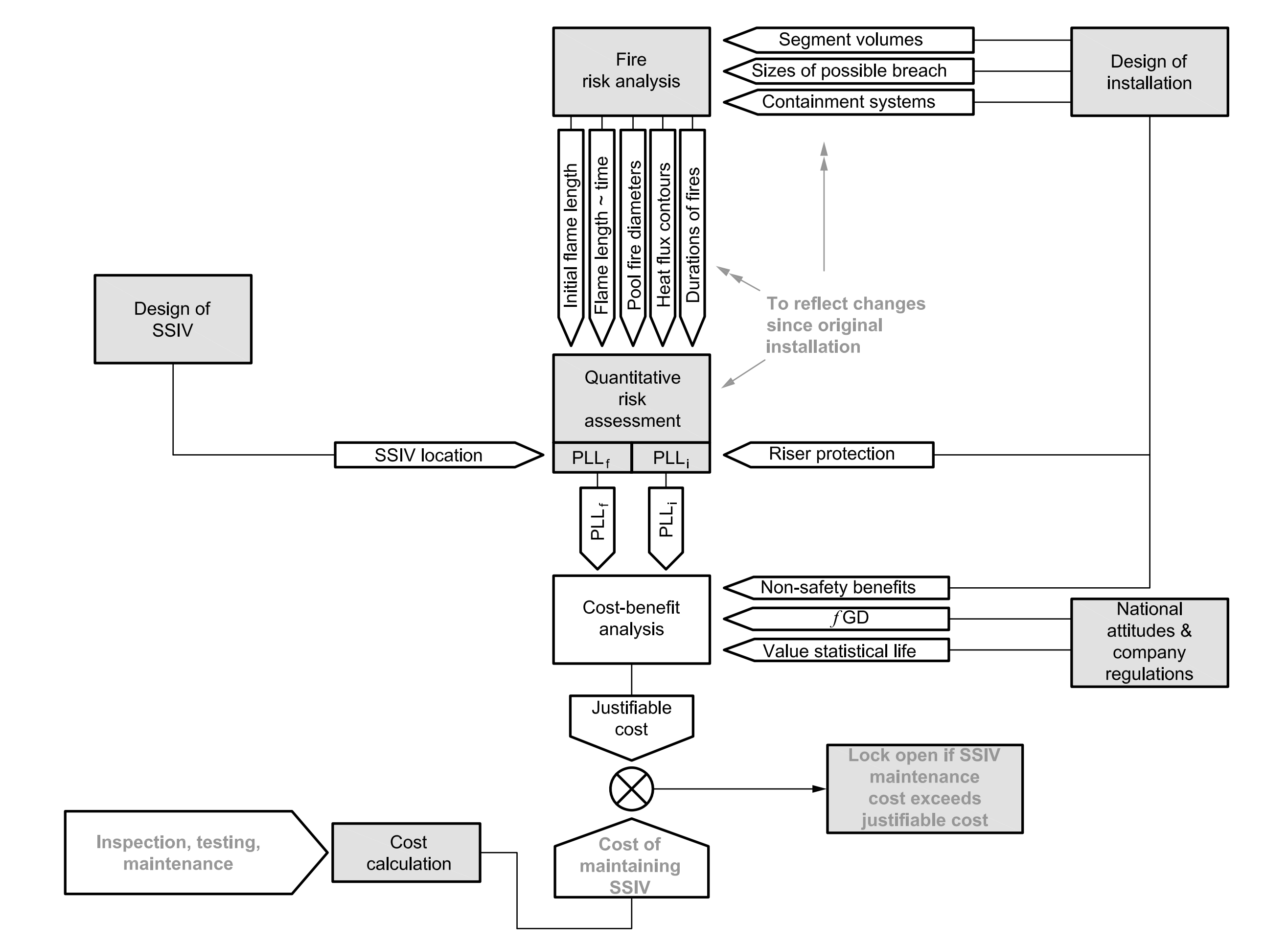
2) Following the Piper Alpha disaster, and while the report of the Cullen Enquiry was being prepared, it is believed that some operators, anticipating that SSIVs were to be made mandatory, decided to avoid the potential log jam of orders by procuring and installing SSIVs without waiting for the new rules (which never were introduced). It is not clear whether QRAs were used at all in these decisions.

Platform-based personnel might be reassured by the presence of an SSIV. Consultation should be carried out before any final decision is made, and personnel views taken into account. Conversely, ongoing inspection and maintenance does increase the risk to divers.

Figure 3 **Information flow – The decision whether to retain an SSIV**



4.3 Testing

4.3.1 General principles

The test is intended to demonstrate that bulk flow has stopped, although an acceptable leak rate may exist. If SSIV closure is initiated while the ESDV remains open, the pressure at the top of the riser should fall rapidly. Once stabilized, the allowable flow rate should be quantified. If it is too small to measure, this will be acceptable. In general, an acceptable flow rate should be defined by the design team (and handed over to the operations team), together with a method for measuring it that is practicable and achievable.

4.3.2 Establishing the pass/fail criteria

The purpose of an SSIV is to minimize the volume and duration of the types of hydrocarbon release described in **4.1**, so as to prevent escalation of any related incident. It is accepted that an SSIV cannot prevent an initial release. An SSIV should, therefore, restrict the inventory so that:

- in the case of a subsea release, conflagration from an ignited gas cloud cannot be sustained; or
- in the case of an above-surface release, a jet fire, if one arises, is not sustained for long enough to cause escalation.

On this basis, a small leak past the SSIV is acceptable, "small" being defined as having no escalation potential, i.e.:

- the flame is neither hot enough nor sustained enough to start new fires; and
- the flow is inadequate to support a major conflagration.

The performance standard for an SSIV might therefore include the provisions that:

- the primary requirement of the SSIV is to close fully and stifle the bulk flow from the pipeline;
- a small residual leakage past the SSIV is acceptable provided it falls well below that required to sustain a fire, or to initiate new fires.

4.3.3 Calculating the test interval

The maximum test interval is obtained by plotting the probability of failure and the maximum acceptable probability of failure against a range of test intervals (Z): the maximum test interval is given by the intersection of the two curves (see Figure 4).

The maximum acceptable probability of failure, P_{Fa}, is given by:

$$P_{\mathrm{Fa}} < \frac{1}{F_{\mathrm{D}} \times Z} \tag{6}$$

where:

F_{D} is the frequency of demand;

Z is the test interval.

This can be assessed using a Poisson distribution, which reflects that, in practice, failures will still occur, and it can be shown that, to satisfy equation (6) – no failures acceptable – the maximum acceptable probability of failure, P^*, is given by:

$$P^* = \mathrm{e}^{-P_{\mathrm{Fa}}} \tag{7}$$

The probability of a failure occurrence for a given failure mode is given by:

$$P_{\mathrm{F}m} = \frac{\lambda_m \times Z}{2} \tag{8}$$

where:

Z is the test interval;

λ_m is the failure rate for the given failure mode.

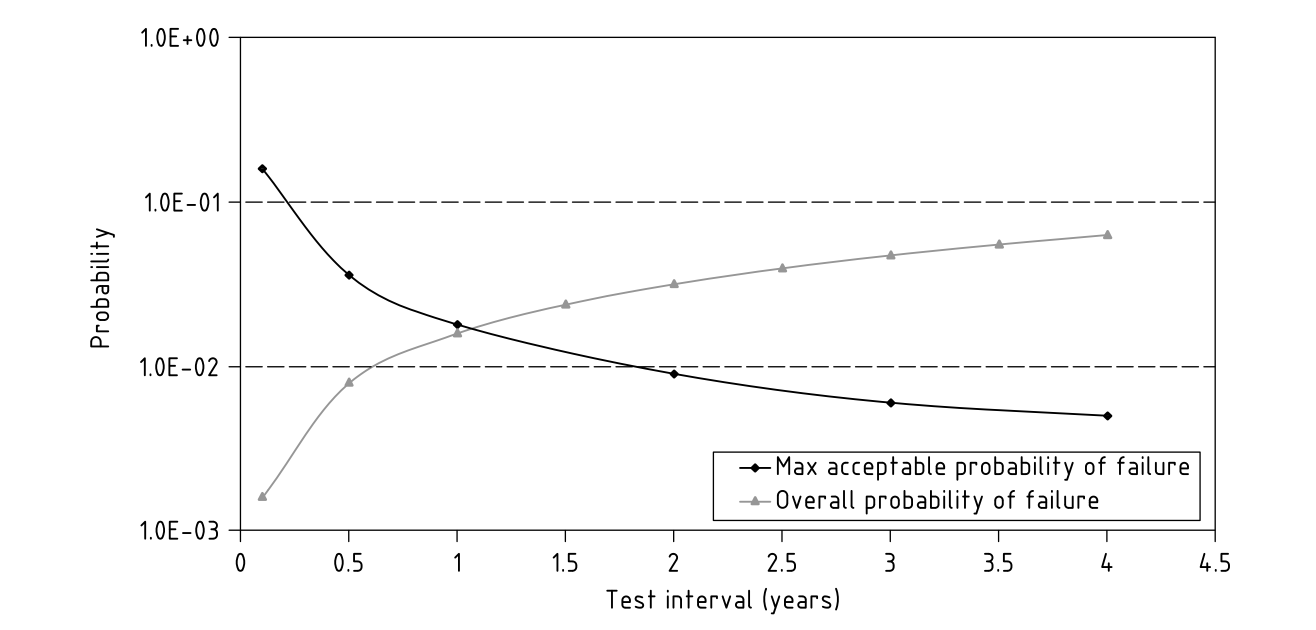
NOTE The value of λ_m can be obtained from published data (e.g. OREDA [6]) or from in-company data.

In the example given (Figure 4), the intersection (maximum inspection interval) is just over 1 year, so the inspection interval would be defined as annual.

In addition, the frequency of testing may be linked to the value of (PLL_i – PLL_f) from the QRA, i.e. the higher the differential, the more frequent should be the testing. For example, if the intersection is at 1.5 years, with (PLL_i – PLL_f) being relatively large, the inspection interval might still be set at annual.

The probability of failure is derived from published, pan-industry data. The maximum acceptable probability of failure is based on the historical shut-down demand frequency on the installation in question, and relates to test frequency. Therefore, calculating the test interval in this way takes account of operational experience, and is preferable to selecting an interval simply on the basis of typical practice.

Figure 4 **Example – Determination of test interval**



5 Selection and use of high pressure in-line isolation plugs

*COMMENTARY ON CLAUSE **5***

This clause provides guidance on the issues that need to be taken into account prior to running an isolation plug into a pipeline as part of an intervention task. It addresses high pressure isolation plugs, i.e. equipment that has to be pigged into place within pipelines and locked in place hydraulically under remote or tethered control, and that is generally required to hold a significant pressure differential. The locking action can subsequently be reinforced by the pressure differential. The clause does not give details of such isolation plugs, or give guidance on plug selection, although the information given can assist in the selection process.

Guidance on the safe isolation of plant and equipment is given in HSG253 [7].

5.1 General

Isolation plugs are used under upset conditions. A situation can exist where either the designed-in isolation provision is not suited to the current requirement (e.g. a length of subsea pipeline requires local isolation for repair purposes), or the designed-in isolation provision itself has failed and requires repair (e.g. an ESDV has failed). In such circumstances, a plug has to be introduced into the pipeline in the manner of a pig, i.e. driven to a location by either the production fluid or a different fluid (e.g. water, diesel or gas) introduced for the purpose. (In some circumstances, multiple plugs might be required.) The plug has to be pigged in, set, tested and, eventually, pigged out, and all these activities can suffer failures that are likely to impact the overall operation and the ongoing availability of the pipeline system. In some cases (e.g. intervention on an ESDV), the plug might have to be moved in only a few metres, in which case it can be located and actuated by a rigid push bar.

Some plugging operations have experienced failures in the past, where the plug has not sealed effectively or has been difficult to unseat and/or remove. When this happens, not only can production be interrupted for a lengthy period, leading to significant loss of income, but several years of time-consuming litigation might follow. For this reason, it is recommended that all possible alternatives are assessed prior to embarking on an isolation plug solution. If this remains the only viable, or the preferred, option then application of the guidance presented in this clause is expected to help to minimize the likelihood of such failures.

5.2 Supply of information

Once it has been determined that a pressure isolation barrier is necessary and that this is to be an inline isolation plug, the supplier should be provided with the information required to select the appropriate plug.

NOTE Annex B gives a pro-forma containing all of the information that a supplier is likely to need to enable correct selection to be made.

Preparations by the executive operator, including dialogue with the contractor, are addressed in **5.3**. The questions in Annex B also form a basis for that guidance.

A copy of the overall job specification should be provided to the contractor, so that they can see their responsibility in the context of the overall project, and make comments as appropriate.

The job specification should be prepared in accordance with standard industry guidance. HSE publication HSG253 [7] has an appendix specific to pipelines.

5.3 Preparations to be made by the executive operator and site operator

5.3.1 General

Before an isolation task is carried out, the executive and site operators should identify as many as possible of the parameters discussed in this subclause, with the information provided in **5.2** being used as a basis.

Following some guidance on planning (see **5.3.2**), the key issues that should be addressed in a pre-project risk assessment are set out in **5.3.3**: unknowns should be identified, and answers found, ahead of the formal risk assessment.

*NOTE A sample failure mode listing, as a basis for the risk assessment, is provided in Annex C. It includes a broader range of functions than just the key issues. More general issues that need to be considered by the executive and site operators are discussed in **5.3.4**.*

5.3.2 Planning

Sufficient time should be allowed for planning in order that a number of HAZIDs, HAZOPs and other risk assessments can be convened. The detail, and hence the number of people involved, is likely to increase as the planning progresses; however, the following stakeholders might need to be involved:

- team undertaking the intervention (both executive operator staff and contractor staff);
- operations staff from the facility (or facilities) involved;
- third parties;
- dive support vessel (or similar) representatives, where applicable;
- plug vendor;

- pigging contractors (if different to plug vendor);
- pump suppliers (if temporary pumps required).

Some of these stakeholders might benefit from an early site visit (where appropriate), and time and resources should be allowed for this.

Where two platforms and/or a dive support vessel or similar vessel are involved, a communications protocol should be agreed. This may involve pre-formatted and agreed templates to be communicated at different stages. Bridging documents between safety management systems should cover all reasonably foreseeable eventualities.

If third-party verification of the project is required, the planning schedule should allow for this.

Time should also be allowed for the management of change process where applicable (see PD 8010-4:2012).

5.3.3 Pre-project risk assessment

5.3.3.1 Setting the plug

Control of the plug may be via a tether or may be effected remotely. In the latter case, the initiation may be by a signal, or by a pressure pulse/differential on a receptor on the plug.

Local conditions have been known to make it difficult to achieve the necessary reverse pressure differential to set a plug. This could have implications for the particular task.

The following factors should be taken into account:

- how the slips are set;
- how the slips are subsequently retracted and whether there is a chance they might not retract fully and cleanly;
- how the seals are set;
- the extent to which the seals are exposed to the product after they have been set.

A pipeline stress analysis should be carried out if appropriate.

5.3.3.2 Pressure monitoring

The primary purpose of the plug is to retain fluids at pressure so that a limited section of a pipeline can be reduced to atmospheric pressure (or possibly hydrostatic pressure) in such a way that it is safe for human intervention to be carried out. To this end, it is necessary to monitor pressure continuously to ensure that the pressure retention is fully effective, and in such a way that the intervention can be reinstated before safety is compromised in the event that the retention starts to fail. The usual method for monitoring is double block and bleed, where two isolations are put in place and the cavity between them monitored for pressure increase, with any build-up of fluid vented. With an in-line plug, the cavity cannot be properly vented, since the only place to vent it is into the depressurized section. Therefore, the cavity is monitored for pressure build-up (double block and monitor).

This is critical to the safety of the operation, and the whole process of sealing and monitoring should be examined in detail to ensure that the system will be fully effective. If the pressure monitoring is not fully reliable, either the task will have to be curtailed, or pressure retention could be lost with disastrous consequences.

5.3.3.3 Seals and packers

The pressure is held by the seal and packer arrangement and, therefore, it is critical that this will work satisfactorily for the duration of the intervention. The materials should be fully suited to the fluids to which they will be exposed, since degradation over time could necessitate abandoning the task. Therefore, it is important to establish the original specification for the materials, and whether this is suitable, and also what tests have been carried out, and under what conditions, to establish suitability if there is any doubt.

5.3.3.4 Power

Power is required both for communications and for actuation (setting and release). It is important to ensure that, subject to the longest reasonable foreseeable delay, it will still be possible to initiate the un-setting process, to confirm that this has been successful, and to track the plug to recovery. There should be adequate power, under all conditions, for two attempts at setting the plug without compromising all other power requirements. Account should be taken of the tolerance of the plug to conditions and delays, and of the location of the battery on the plug.

As a contingency, there should be a back-up method for un-setting the plug if all power is lost.

5.3.3.5 Plug equipment

A full review of the plug and its control system is recommended, which should include:

- reliability of electronics and small bore hydraulics;
- redundancy;
- robustness of moving parts, long-term, e.g. slips.

5.3.3.6 Position location and management

For tether-less operations, the ability to communicate with the plug is critical, since all setting, monitoring and un-setting has to be initiated remotely. A full review of the communications system should be undertaken. The location of non-tethered plugs may be by acoustic, magnetic or radioactive methods. The following factors should be determined and taken into account:

- accuracy of stopping;
- method of tracking;
- range, reliability of through-wall communications (if applicable);
- back-up for loss of communications;
- plans for release and pigging out.

If the plug is on a tether, some of these factors are not relevant, but the existence of a tether can be a limitation in itself, i.e. it can interfere with the intervention task.

There should be an independent contingency plan for release for both tethered and non-tethered operations.

In some cases (e.g. intervention on an ESDV), the plug might have to be moved in only a few metres, in which case it can be located and actuated by a rigid push bar.

5.3.3.7 Lifting and handling

Impacts due to collisions while handling a plug on deck, or inadequate space or facilities for preparing a plug, can lead to faults that could escalate to failures during the task. A lifting and handling plan should be provided, showing aids (e.g. eye bolts) and constraints (e.g. hatchways), to enable the contractor to plan the operations. The executive operator's crew at the facility should also be fully conversant with the lifting and handling provision. Delays due to unforeseen difficulties in handling can adversely impact the schedule, and might induce the cutting of corners to regain it, which could be detrimental to the task.

Issues that should be investigated include, but are not limited to:

- whether the crane can lift the plug and its launch aids;
- whether the deck can support the plug and its launch aids;
- whether the deck space is adequate for field team to prepare the plug;
- whether the space is adequate for manoeuvring the plug into/from the launcher/receiver.

5.3.3.8 HAZID and HAZOP

No two isolation projects are the same, and the plug might have to be adapted. A HAZID of the plug, and a HAZOP for the overall project, should therefore be completed as part of the risk assessment. These activities should conform to company management of change procedures (see PD 8010-4:2012). They should be carried out by a team that includes the plug designers, field personnel and executive operator.

5.3.4 Other issues to be taken into account

In addition to the issues in **5.3.3**, the following should also be taken into account:

a) competency of the designers and manufacturers of the plug;

b) competency of the field team provided by the contractor;

c) track record of the plug;

d) feedback from other users;

e) training and readiness of the executive operator's field team;

f) training and readiness of the diving contractor's field team (where applicable);

g) common understanding of the task (executive operator/contractor);

h) communications paths, systems (executive operator/contractor);

i) transportation of the plug;

j) health, safety and security of field teams;

k) levels of checks relative to safety criticality;

l) possible need for back-up with an alternative (e.g. pipe freezing);

m) contingency planning (to include "stuck pig" scenarios);

n) possible need for mock-up for testing.

The design of the plug is carried out by different people, in most cases, to those who will undertake the field deployment. The original designers might have moved on and it is important to ensure that the current project team is fully conversant with the design of the plug, especially if modifications are required for the specific task: they need to understand why the plug is configured as it is. The personnel who will deploy the plug also need to understand all the systems. The track record should be scrutinized, including checking which members of the current design and field teams supported previous successful deployments. The supplier's teams should be encouraged to be honest about previous problems encountered.

The site operator should also ensure that their own platform (or terminal) teams are fully conversant in pigging operations. As well as supporting the plug field team, they might be required to run cleaning and calliper plugs prior to the plug team embarking.

All parties should have a common understanding of the task to be carried out. The task starts at preparations for launch and continues until recovery. There is a danger in concentrating on the setting and pressure monitoring: often, the un-setting and pigging out, particularly after a lengthy hold period, can be the most hazardous. The communication paths between personnel should be confirmed, and it should be ensured that checks run on the system are commensurate with the safety hazards identified.

The list above is not exhaustive. Other issues might need to be taken into account, depending on the work being undertaken. In-line plugging is a complex task and should not be undertaken if a less complex alternative is available. Alternatives or augmentations should be scrutinized in detail. High friction pigs, for example, can interfere with setting the main plug by changing the flow characteristics.

All systems and procedures should be assessed to determine whether an alternative approach might be more effective. This could range from a definition of all the checks that need to be made prior to launch (e.g. which valves should be open and which shut), to the nomination of who should sign off each check so that there is complete clarity of task. The respective responsibilities of executive operator and contractor staff should be explicit.

6 Pipeline integrity data exchange

Pipeline integrity data exchange is employed as part of the integrity management process where any pipeline passes through the domain(s) of more than one operator, for example where product is exported via another operator's platform, or via a tee into another operator's pipeline. Sufficient, timely, and structured data exchange supports the need for cooperation, ensuring that the executive operator of the line has a full integrity and operating picture of the other executive operators' interconnecting pipelines. This might also enable other operators to have awareness of the condition of third-party risers on their installations and pipework within their installation safety zones.

*NOTE 1 A definition of integrity management is given in PD 8010-4:2012, **3.1.6**.*

NOTE 2 Attention is drawn to paragraph 17 of the Pipelines Safety Regulations 1996 [8].

In the event that a serious occurrence takes place, it is essential that the operators of inter-linked pipeline systems have all of the necessary information readily available to enable the right decisions to be made in an emergency situation. A set of standardized data sheets should therefore be used, so that there is uniformity in the collection of data.

The recommended structure consists of two master pro-forma sheets, of which examples are given in Annex D and Annex E: the main data sheet (Annex D) which contains data that remain largely unchanged from year to year, and the annual data exchange sheet (Annex E) which contains integrity data pertinent to the previous period of operation. A sample main data sheet, filled in with a hypothetical example, is provided in Annex F. The data sheets can be embedded in the individual operators' pipeline integrity management schemes. They may also be integrated with documents such as the major accident prevention document (MAPD).

The sample data sheets are intended to be as comprehensive as possible, but not all of the parameters listed are appropriate for every pipeline system; for example, some of the parameters generally measured for gas, oil and water injection lines are different. Persons completing the forms can insert "Not Applicable" (N/A) in irrelevant boxes, or tailor the sheets by adding or removing boxes as necessary.

NOTE 3 The advantage of putting N/A in irrelevant boxes is that there is no uncertainty as to whether a parameter has merely been forgotten.

All operators involved (there might be more than two) should agree the format of the sheets that they use to exchange integrity data.

If a data sheet is revised, the revised version should be agreed by all the executive and site operators to ensure that they are aware of the changes.

Where numeric data are to be entered on a data sheet, the units should be explicitly stated to avoid ambiguity.

7 Caisson and J-tube integrity management

NOTE This clause is applicable to both new and existing caissons and J-tubes. It is assumed that J-tubes and caissons incorporate risers conveying pressurized fluid.

7.1 Integrity issues

7.1.1 General

Caissons and J-tubes are often safety-critical elements on an offshore platform. Whilst caissons and J-tubes are designed and installed to protect risers, they also obstruct access to the outer wall of the riser within the annulus, which makes inspection very difficult. The difficulties surrounding inspection accentuates the requirement to manage the annulus contents.

To understand the integrity threats for a particular caisson or J-tube it is necessary to understand the detailed component layout, as each caisson and J-tube is slightly different.

7.1.2 Design philosophy

There are a number of design options:

a) design as a riser – wall thickness to achieve a safety factor as required by the specified design code, with or without corrosion allowance, based on design pressure of the highest rated riser;

b) design to yield/not burst – could include a corrosion allowance, but no safety factor, based upon the design pressure of the highest rated riser;

c) design to vent pressure – either with a pressure relief system at the top or, in the case of a J-tube, designed to blow out the seal and vent at the bottom.

In the case of pre-installed J-tubes, the design pressure of all risers to be installed subsequently almost certainly would not be known. It would be necessary to back-calculate the safety factor, or there might have to be a trade-off between safety factor and corrosion allowance. In either case, management of the annulus is critical to the ongoing integrity, and the strategy should be part of the design. In the case of sealed caissons, particularly those with dry annuli, it is unlikely that the design would include a safety factor for an upset event of low probability, so that there has to be a balance between the design pressure and the pressure relief philosophy.

7.1.3 Principal threats

The primary threat to both riser caissons and J-tubes is a riser failing, consequently releasing pressurized fluid into the annulus and exposing the structure to above ambient pressure. Given that the caisson or J-tube protects the riser from environmental loads and all but extreme accidental loads, the most likely cause of failure is loss of containment due to corrosion. This could be internal or external corrosion and, in the latter case, the difficulties of inspection make this much more likely than in most pipeline and riser situations. This is particularly relevant to J-tubes, where the bellmouth seals are installed as part of the riser pull-in process and are prone to leaking, hence contributing to a corrosive environment inside the annulus, e.g. through the dilution of corrosion inhibitors.

A lesser threat is that the caisson or J-tube itself suffers from corrosion such that, if a riser fails, it cannot hold/vent pressure as intended (see **7.3**).

7.1.4 Failure implications

If corrosion is ongoing, and the pipeline is never shut in, the thinnest point of the riser wall will eventually fail. The result of this will be a slow build-up of product and pressure within the annulus. In the case of a caisson, the pressure builds up until either the caisson contains the flowing pressure, or the caisson fails abruptly. The likelihood of caisson failure is increased if it suffers from corrosion itself.

In the case of a J-tube, the pressure increases until it overcomes the hydrostatic pressure at the bellmouth and the resistance of the seal, and vents via the same route. Oil rises to the surface, giving the first warning of failure. In the case of gas, dissipation through the water column usually prevents total inundation of the platform, and gas detectors can detect a leak before catastrophic failure occurs. However, if the J-tube is itself corroded, it might fail before the seal can be displaced. As a result, a leak of the product could occur above water level, or even topsides.

In the case of a caisson or J-tube containing a flowline, if the corroded wall is capable of containing the flowing pressure but has a capacity well below the closed-in tubing head pressure (CITHP), then, if the line is shut in and experiences the full CITHP, the failure can be so rapid that it behaves like a rupture. Alternatively, the pressure can build up until either the caisson contains the closed-in pressure, or the caisson fails. If the caisson contains the pressure, this could result in excess external pressure on the other risers, possibly resulting in collapse. In the case of the J-tube however, the inertia of the water low in the annulus, augmented by the seal at the bottom, can result in a quantity of water being driven upwards, causing a structural failure high up in the annulus.

In the case of a flexible riser (which is only found in a J-tube), the failure might be of the pinhole nature if the polymer sheath fails, creating a leak path through the various layers, or could be abrupt (equivalent to a rupture) if the armour wires were to fail due to corrosion. Thus the same failure scenarios should be addressed as for a rigid riser.

7.2 Description of system

The overall system should be clearly understood before work commences on the detailed design of the caisson or J-tube. Table 1 gives a non-exhaustive list of issues that should be assessed in order to build up an understanding of the system and of potential threats.

Table 1 **Description of system – Key considerations**

Description of system	Key considerations
What risers/J-tubes are contained within the unit and what are they carrying?	• Materials used to fabricate the risers • Corrosivity of product in risers • Internal risers installed to facilitate annulus management? • Isolation of dissimilar metals
Coatings and corrosion prevention	• Coatings on risers and internal J-tubes • Internal coating of caisson or J-tube • Anodes?
Retrofitted or pre-installed?	• Quality/current condition of coatings • Water ingress during construction
J-tube or a caisson?	• Damage to coatings during pull-in of riser to J-tube
Installed in a conductor slot or outside the jacket?	• Complexity of installation impacting on condition • Vulnerability to external impact
Supported at the bottom or by dead weight support (DWS)?	• DWS implies movement at the bottom seal due to differential pressure/temperature
Clamps and guides?	• Corrosion of bolts
Pressure rating/containment capacity	• Can caisson or J-tube contain the highest pressure of all risers contained? • Venting arrangements?
Riser design pressures	• Are design pressures still applicable? • Impact on pressure containment capacity
Riser design temperatures	• Possibility of differential expansion between risers, and between riser and caisson or J-tube
Installation date	• Timescale for any degradation

For existing caissons and J-tubes, it is expected that a HAZID would have been carried out as part of the design process, looking at scenarios such as the probable caisson response in the event of a riser failure (high pressure in annulus). If the results of this exercise are not readily available, then a review of the system can be used to investigate these scenarios.

The key considerations listed in Table 2 (see **7.3.2**) can also be used by the designer of a new riser system to highlight issues that need to be addressed.

7.3 Design intent

7.3.1 General

The design intent of the system should be clearly understood before work commences on the detailed design of the caisson or J-tube. The tables in this subclause present the key considerations that should be assessed in order to build up an understanding of the design intent of the system, in each of the following discrete areas:

- overall design considerations (**7.3.2**);
- top arrangement (**7.3.3**);
- splash zone (**7.3.4**);
- bottom arrangement (**7.3.5**);
- J-tubes within caissons (**7.3.6**).

7.3.2 Overall design considerations

Table 2 gives a non-exhaustive list of issues that should be assessed in order to build up an understanding of the overall design intent of the system.

Table 2 **Overall design intent – Key considerations**

Design intent – Overall design	Key considerations
Designed for pressure containment?	• Sealed or open • Venting/bursting provision
Wet or dry annulus?	• Free flooded (seawater) • Potable water • Treated seawater/treated potable water • Nitrogen
Riser and caisson corrosion protection?	• Internal CP (free flooded) and external CP • Caisson and riser coatings (dissimilar metals)
Corrosion inhibition measures?	• Nitrogen purge • Sampling/replenishment • Inhibition throughout height of caisson/J-tube • Mixing of corrosion inhibitor (centralizers/baffles)
Provisions for annulus monitoring?	• Access for sampling/top-up • Access for purge • High/low pressure alarm installed • High/low level alarm installed
Provisions for inspections?	• Riser inspections • Splash zone inspections • Annulus inspections

7.3.3 Caisson/J-tube top arrangement – Specific design considerations

The top of the caisson or J-tube is generally the most accessible part, and contains the provision for access (for sampling/replenishment, if such provision has been made) and any purging and/or venting arrangements. It is also the point, on a caisson or J-tube in good condition, that is most likely to fail if the annulus becomes pressurized due to a riser failure, potentially leading both to structural damage and to dangerous substances inundating the platform. Therefore, the integrity of this area is critical.

Table 3 gives a non-exhaustive list of issues that should be assessed in order to build up an understanding of the top arrangement of the system.

Table 3 **Top arrangement design intent – Key considerations**

Design intent – caisson/J-tube top arrangement	Key considerations
Arrangement at the top?	• Open • Welded • Rigid seals (material selection, differential expansion) • Gaiters
Provision of a pressure relief system?	• Are there pressure-containing risers within caisson/J-tube? • Response to annulus pressurization?
Wet or dry annulus?	• Free flooded (seawater) • Potable water • Treated seawater/treated potable water • Nitrogen • Nitrogen blanket • Moist air
Riser and caisson protection?	• Internal and external CP • Caisson and riser coatings (dissimilar metals at top plate) • Float coat
Corrosion inhibition measures?	• Nitrogen purge • Sampling • Replenishment • Inhibition throughout height of caisson/J-tube • Mixing of corrosion inhibitor (centralizers/baffles)
Provision for annulus monitoring?	• Access for sampling/top-up • Access for purge • High/low pressure alarm installed • High/low level alarm installed • Gas pressurization system (J-tube)

7.3.4 Caisson/J-tube splash zone arrangement – Specific design considerations

The splash zone is a critical area for all risers as it is the most difficult to inspect. Remotely operated vehicles (ROVs) cannot work right up to the surface in most weather conditions, and abseilers tend not to immerse themselves, so that there is usually a gap in the coverage. This is often reflected by cladding the splash zone, on top of the principal coating, with materials such as nickel alloy metals or solid polyurethane.

The bottom seals of J-tubes are not always fully effective, so that a tidal zone can be created within the annulus. This can also occur in caissons that are open at the bottom. Unless nitrogen, or similar, is used to maintain the above-water section stable and dry, the result can be a zone of higher corrosion threat, depending upon the condition of the coatings.

NOTE At the time of publication of this part of PD 8010, no cases have come to light of reinforcement of the coatings inside the annulus in the area of the tidal zone.

Table 4 gives a non-exhaustive list of issues that should be assessed in order to build up an understanding of the splash zone of the system.

Table 4 **Splash zone design intent – Key considerations**

Design intent – Caisson/J-tube splash zone arrangement	Key considerations
Arrangement at bottom?	• Open (potential internal tidal effect) • Closed (reliability/integrity of seal)
Riser and caisson protection?	• External cladding of caisson/J-tube • Internal coating of caisson/J-tube • External coatings of risers (dissimilar metals) • Internal CP (free flooded) and external CP
Corrosion inhibition measures?	• Nitrogen purge throughout height • Sampling throughout height • Inhibition throughout height of caisson/J-tube • Mixing of corrosion inhibitor (centralizers/baffles)

7.3.5 Caisson/J-tube bottom arrangement – Specific design considerations

The bottom of the caisson or J-tube is a critical area as, in many cases, it is prone to leaks. In the case of J-tubes, bottom seals frequently leak to some extent, such that the originally benign annulus content (e.g. inhibited water) becomes diluted and protection is degraded. Even the bottom seals of deadweight caissons have been known to leak after a period of time, probably as a result of differential expansion of risers shearing the bonds. In most cases, the preferred method of discovering a leak would be through sampling of the annulus fluid, rather than by other indirect means such as discovering corrosion. Sampling programmes should take account of the design of the bottom arrangement; i.e. J-tube seals are more prone to failure than caisson bottom arrangements, and hence sampling frequency would be expected to be higher.

Table 5 gives a non-exhaustive list of issues that should be assessed in order to build up an understanding of the bottom arrangement of the system.

Table 5 **Bottom arrangement design intent – Key considerations**

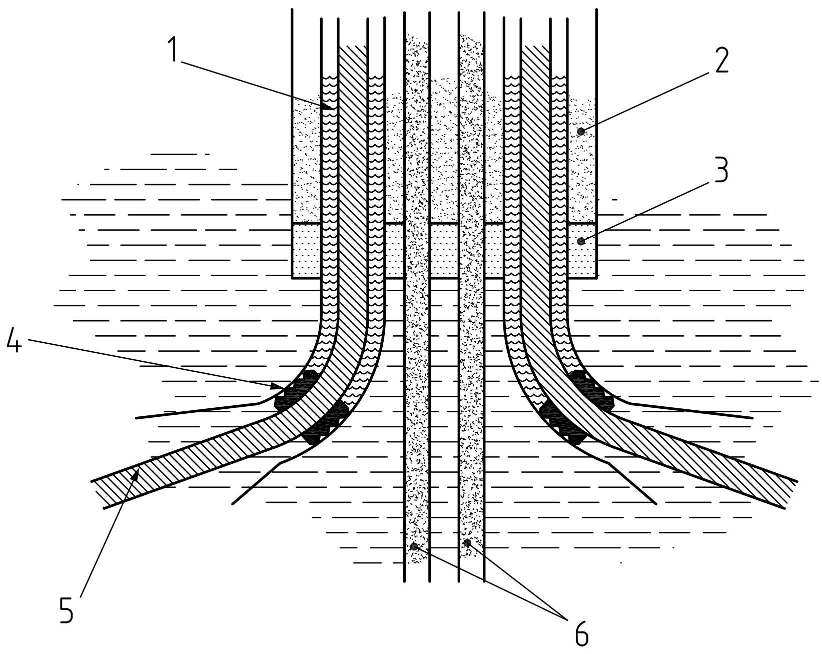
Design intent – Caisson/J-tube bottom arrangement	Key considerations
Arrangement at the bottom?	• Open • Welded • Rigid seal (differential expansion, degradation of grout) • Plug
Wet or dry annulus?	• Free flooded (seawater) • Potable water • Treated seawater/treated potable water • Nitrogen
Riser and caisson protection?	• Internal and external CP • Caisson and riser coatings (dissimilar metals at base plate)
Corrosion inhibition measures?	• Nitrogen purge throughout height of caisson/J-tube • Sampling at bottom • Inhibition throughout height of caisson/J-tube • Mixing of corrosion inhibitor (centralizers/baffles)
Provision for annulus monitoring?	• Inspection of plug/seal • Leak testing of bottom seal • Flooded member detection (bridges)

7.3.6 J-tubes within caisson – Additional design considerations

Some caissons contain both risers and J-tubes, as depicted in Figure 5. This does not alter the integrity considerations, but it does add to the complexity of identifying components at the top and bottom (e.g. which annuli have pressure sensors, or which annuli are vented), and of investigating failure modes.

The primary consideration, over and above those identified in **7.3.2** to **7.3.5**, is whether poor annulus management could lead to corrosion on both the outside and the inside of the J-tube, making a breach more likely. The follow-on question is what this would imply in terms of further annulus management, and the threat of external corrosion of any risers within the caisson or the riser in the J-tube.

Figure 5 **Risers and J-tubes within a caisson**



Key

1 J-tube annulus

2 Caisson annulus

3 Caisson bottom seal

4 J-tube plug

5 Riser or cable

6 Risers

7.4 Corrosion control and monitoring

7.4.1 General

In most instances, the caisson/J-tube design process consists of an iterative process between design, risk assessment and integrity strategy, to ensure that integrity threats identified during the risk assessment, and risks arising from those threats, are reduced or eliminated.

NOTE Recommendations for risk assessment are given in PD 8010-4:2012. Examples specific to caissons and J-tubes are provided in Annex G of the present part of PD 8010.

Once the caisson or J-tube is in operation, the preservation of its integrity relies upon effective integrity management. There are three main activities that are typically carried out to maintain and monitor the caisson/J-tube integrity:

- external caisson/J-tube inspections;
- riser in-line inspections (intelligent pig or similar technology);
- annulus management.

Since corrosion is the principal threat to the integrity of caissons/J-tubes and the risers within, it is essential to monitor for such on a regular basis. This subclause therefore focuses on corrosion control and monitoring.

Inspection techniques described in this subclause, in particular those not routinely used for the inspection of caissons and J-tubes, might or might not be successfully adopted to suit a specific application. Therefore, expert advice should be sought before using a specific technique.

7.4.2 External inspection

External inspections of caissons and J-tubes are routinely carried out in almost all existing units. Checks for signs of corrosion, damage and CP depletion (subsea) are made. Above the splash zone, the caisson/J-tube external inspection is carried out either from an easily accessible location, e.g. using binoculars, or by abseilers who can deploy various imaging and non-destructive testing (NDT) tools. Subsea, much of the inspection is carried out by ROV (typically general visual inspection and CP), with divers inspecting inaccessible locations (such as the riser break-out below the caisson base plate).

The splash zone is a critical area for all risers as it is the most difficult to inspect (see **7.3.4**). Riser inspection tools are available to carry out visual and other limited NDT inspections in the splash zone, as well as above the splash zone. In the southern North Sea, some operators try to run the ROV inspection at high tide, and the abseiling at low tide, to create an overlap.

In general, external corrosion gives no more concern in the case of caissons and J-tubes than for other risers, and inspection intervals and methods would be expected to be similar.

7.4.3 In-line inspections

Internal and, in most cases, external corrosion of the risers themselves can be detected by in-line inspection tools, which are also commonly referred to as intelligent pigs. Intelligent pigs are able to deploy a wide variety of inspection techniques, the most commonly used of which are magnetic flux leakage and ultrasonic testing.

In the case of trunk export lines or interfield lines (platform to platform), pigging may be performed regularly without interrupting production, as the inlet and outlet points of the pipeline are easily accessible. However, in the case of flowlines, it is likely that pigs will be run infrequently, assuming pigging is even possible, because in most cases, both a subsea pig launcher and a pig receiver (topside) would need to be installed.

Alternatives include self-propelled or differential pressure-driven tethered bi-directional pigs that can be inserted and retrieved topsides. However, the use of these tools often requires that the riser is isolated and hydrocarbon freed.

Where pigging is not considered feasible, operators have to rely on assessments of corrosivity and estimates of internal corrosion.

7.4.4 Annulus management

Corrosion of the outside of the risers and of the inside of the caisson/J-tube can occur if the annulus is not properly managed. In most cases, a visual inspection inside the caisson is restricted due to the series of centralizers or baffles, assuming that access is provided at all. The difficulty surrounding inspection further accentuates the requirement for effective annulus management.

In a free-flooded caisson, corrosion is prevented by CP and the anti-corrosion coatings on the risers and caissons. There might be little scope for inspection in these circumstances, but it might be possible to insert a camera from below to check on anode depletion.

In a sealed caisson, corrosion in the annulus is typically prevented by ensuring that the annulus content is benign (e.g. dry nitrogen or treating the seawater/potable water with anti-corrosion chemicals). It is important to monitor the condition of the annulus content, and replenish the protective products regularly.

Where an annulus is wet, the annulus fluids should be sampled on a regular basis, typically at intervals not exceeding 1 year, to check for evidence of corrosion products and the concentration of corrosion inhibitor. Centralizers and baffles can prevent thorough mixing of the chemicals, and samples should be recovered from more than one level if possible. In addition, a pro-active replenishment strategy should exist. If chemical levels consistently drop below target levels, despite replenishment, the bottom plug/seal should be checked for leak tightness.

Where an annulus is dry, it might be necessary to purge/replenish the gas in the annulus on a regular basis. Any purging or chemical injection tubing should be installed such that the full height of the caisson/J-tube will be purged/inhibited.

If a caisson or J-tube is vented, it should be determined whether the venting is to atmosphere (e.g. via a bursting disk) or to the flare system. In the latter case, it should be ensured that the vent is clear and will work correctly if required.

Installation of an annulus pressure monitoring and alarm system is beneficial, if the top arrangement is such that a build-up of pressure in the caisson could lead to a catastrophic failure.

The ability to inspect, sample, etc. varies from installation to installation, and the frequency set for carrying out the activity varies with regard to how much can be achieved in practice. The integrity should be assessed at least annually, so as to ensure that any changes can be captured and their impact can be addressed.

7.4.5 Integrity management Issues

The following list describes a number of common issues that should be addressed regarding the management of caisson and J-tube integrity.

- **Responsibilities**. Riser inspection can fall through the gap between organizations responsible for the integrity management of pipelines and topsides. This problem is exacerbated in the case of many caissons and J-tubes because more topsides intervention is required (e.g. pressure monitoring, alarm systems, sampling and replenishment, nitrogen purging) than the usual inspection associated with individual risers. Responsibilities should be clearly defined, with one person being given the overall responsibility and the authority to ensure that necessary actions are carried out.

- **Management support**. Due to the complexity of reporting arrangements, managers and budget holders might not be aware of the criticality of some of these systems. On the basis that caissons are commonly used for other purposes on offshore installations, there is a prevalent view that caissons and J-tubes are merely structural elements, which obscures potential threats. The results of the risk assessment should be communicated to the financial decision makers and used to highlight the criticality of aspects of the system, and to make a case for support. A responsible person should be appointed to ensure that this happens.
- **Platform awareness**. Due to organizational arrangements and the sometimes obscured nature of subsea pipelines and related equipment, operations personnel on platforms might be less aware of safety-critical elements associated with pipelines. To bridge this gap, the purpose of certain intervention activities should be made clear to the relevant offshore personnel and to those controlling offshore activities. In particular, the implications of alarms, where installed, should be highlighted.
- **Third parties**. A third party becomes involved in integrity management of caissons and J-tubes when the legal duty to manage the integrity of the caisson/J-tube and the contained riser(s) rests with different parties. In other words, the agreed system boundaries are such that the pipeline operator who is responsible for the riser is not responsible for the caisson or J-tube itself. This is more likely to be the case for caissons rather than J-tubes, because J-tubes are part of the pipeline. In this case the operatorship for the caisson lies with either another pipeline operator or the platform duty holder. In an extreme case, when a caisson contains risers operated by different pipeline operators, the installation duty holder could be a third party to both organizations, which further complicates the situation. Therefore it is good practice that the management systems of the companies involved recognize other third parties, and reporting and communication lines between stakeholders are established. The integrity information exchange pro-forma sheet (see examples in Annex D and Annex F) should be used to identify all third party involvement.

  NOTE Attention is drawn to the legal framework set out in the Pipeline Safety Regulations 1996 [8], Regulations 17 and 19, the Offshore Installations and Pipeline Works (Management and Administration) Regulations 1995 [9], Regulation 8, and the Offshore Installations (Safety Case) Regulations 1992 [10], Schedule 2(14) in respect of cooperation between third parties.

8 Emergency shutdown valve (ESDV) testing

8.1 General

An ESDV is a valve that closes in an emergency to shut down a process. Every hazardous duty pipeline incorporates an ESDV to isolate it from the topsides (or terminal) pipework in an emergency. This clause is concerned with testing ESDVs.

Pipelines contain a large inventory. A typical 10 km long, 10 in (273.1 mm) OD pipeline contains over 460 m^3 of product at ambient pressure, and a gas line under pressure contains many times more. In the event of a major break in containment occurring topsides, all this product is available to feed a fire or build to an explosion. The ESDV has to be capable of stopping the flow of fluid in the pipeline to prevent this (although minor leakage past the valve might be acceptable if it cannot represent a threat to safety). An ESDV cannot prevent an incident, but it can stop an incident from escalating to a catastrophe. If the ESDV does not close fully, then any leakage past it has to be insufficient to support ignition, sustain a damaging fire, or to build up enough in any enclosed space to create an explosive situation.

NOTE 1 Attention is drawn to the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 [11] in respect of the requirement to report ESDV test failures.

The successful closure of an ESDV depends upon the successful operation of each of:

- manual stops, automated trips, safety shut-down processes, etc. (which trigger);
- the control system (which demands a response from);
- the actuator (which strokes);
- the valve itself.

The maximum allowable time from the initiation to the valve being fully closed is defined in the specification or manufacturer's performance standard. The closure should not be so rapid as to cause stresses and/or hydraulic shock to the valve and associated pipework. In general, closure times should be not faster than:

- 2 in [3)] and 3 in valves: 1 s;
- 10 in valves: 3 s;
- 12 in valves: 4 s;
- 14 in valves: 5 s;
- 16 in valves: 6 s;
- 20 in valves: 8 s.

NOTE 2 Attention is drawn to the Offshore Installations (Safety Case) Regulations 1992 [10] in respect of acceptable closure times.

NOTE 3 It is expected that the performance standard will contain all necessary details, including minimum and maximum allowable closure time, allowable leak rate (if any), partial closure test requirements (if any), and which modes of shut-down should close the ESDV.

8.2 Objectives

The purpose of testing is to ensure that all the components function correctly to achieve a full closure within the time defined by the performance standard, on first demand, both from the control room and locally.

Regular testing can reduce the probability of failure on demand (i.e. increases reliability).

It provides data allowing trending of parameters (e.g. closure speed) that might highlight a degradation in performance over time. This allows the degradation to be corrected before the ESDV fails a test or, more critically, fails to close in a real emergency.

The test can also be configured to provide a measure of the rate of passing, in the event that the valve does not achieve a 100% seal.

NOTE Some operators allow a planned or unplanned shut-down to replace a scheduled closure test, provided that the necessary parameters are recorded.

3) 1 in = 25.4 mm.

8.3 Test procedure

NOTE This subclause describes a commonly used procedure. Alternative methods of leak detection might be available.

8.3.1 General

The test should start with a visual inspection of the valve and actuator to look for any leakage (e.g. product, hydraulic fluid, air), damage, corrosion, etc.

The visual inspection may be scheduled separately as part of a planned maintenance routine, especially since the removal and subsequent replacement of passive fire protection can be time-consuming. However, a leak might occur only during a test, so the ESDV should still be observed during the test.

The control system should be checked for leakage (e.g. hydraulic fluid).

Following the visual inspection, a full closure should be instigated, to confirm that the system (or that part of the system tested) is functioning.

An internal body leak test should then be carried out to establish whether the valve is passing and, if so, at what rate.

NOTE 1 Some operators specify partial closure tests to be alternated with full closure tests. This demonstrates that the valve will move off its seat, but does not demonstrate that it will fully close, so many operators now carry out only full closure tests (but not always with a leak-off test included).

NOTE 2 The internal body leak test (leak-off test) is the ultimate means of confirming that, in the event of a break in containment, the rate at which product might reach that location is not so high that it threatens "the installation's ability to control safely the hazards produced by such a leak" (see HSE publication L82 [12]). This is done by measuring the change of pressure behind the valve over time, and converting that to a flow rate.

The internal body leak test should be carried out as follows:

a) check and calibrate all relevant pressure gauges;

b) close the ESDV;

c) isolate a section behind it, closing valves in the specified sequence;

d) depressurize that section;

e) measure the rate of re-pressurization.

NOTE 3 The calculation might be carried out by support engineers onshore rather than by the test team offshore.

The arrangement is illustrated by Figure 6, which shows the valve under test. If the ESDV passes fluid, the pressure rises in the section behind it (A in Figure 6), and the rate of pressure rise can be converted to a volumetric flow rate, as follows.

- volume of piping behind ESDV = V m^3;
- pressure behind ESDV at start of test = P_1 bar [4)];
- pressure behind ESDV at end of test = P_2 bar;
- change in volume of gas behind ESDV = $V \times (P_1 - P_2)/P_2$ m^3;
- time for pressure to rise from P_1 to P_2 = t min;
- volumetric leak rate = $V \times (P_1 - P_2)/(P_2 \times t)$ m^3/min.

[4)] 1 bar = 10^5 N/m^2 = 100 kPa.

This test can be carried out only at the available pressure [typically the normal operating pressure (NOP)] which, in some cases, can vary from test to test (e.g. reservoir pressure might be declining). While the leak rate at the operating pressure is relevant to assessing whether the leak might threaten the facility, pressure can build up in a pipeline during a shut-in. Furthermore, trending of the results may be facilitated by relating the volumetric leak rate to a fixed pressure, such as the MAOP.

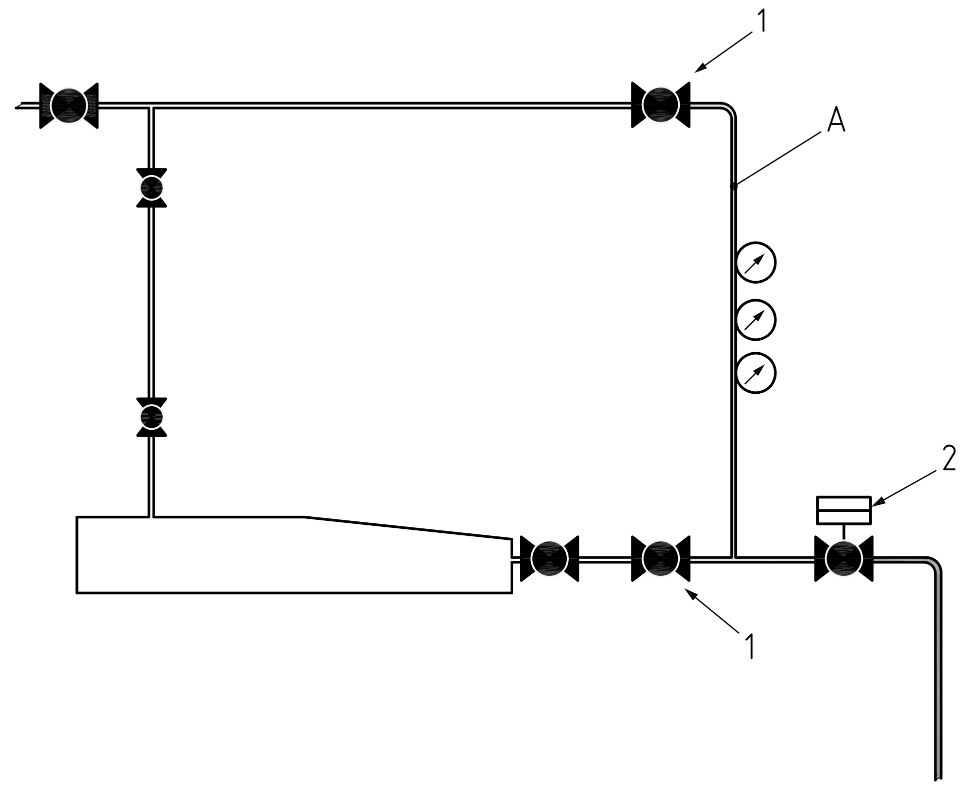
The result can be related to MAOP as follows:

- pressure in main pipeline during test (see Note 4) = P_T bar;
- maximum allowable operating pressure = MAOP bar;
- volumetric leak rate at MAOP = MAOP × V × (P_1 – P_2)/(P_T × P_2 × t) m^3/min

It is recommended that the leak rate both at actual pressure, and normalized to MAOP, should be trended. However, the performance of some seals can improve at higher pressure.

NOTE 4 The arrangement illustrated in Figure 6 assumes that the isolation valves themselves are not passing fluid.

Figure 6 **ESDV leak-off test arrangement**



Key

1 Isolation

2 ESDV under test

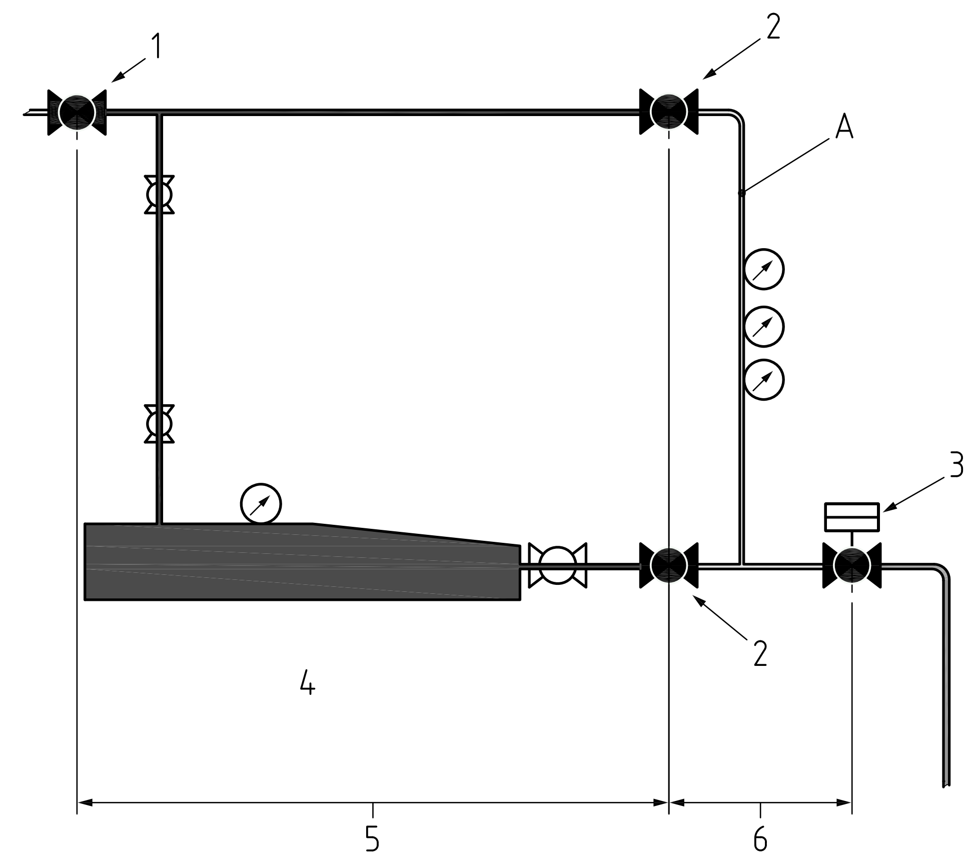
8.3.2 Passing isolations

If the pressure is lower behind a passing isolation then leakage through the ESDV might be underestimated. If the pressure is greater behind the isolation then leakage through the ESDV might be overestimated. If the pressure behind the isolation is unknown, then there can significant uncertainty regarding the ESDV leak rate.

To account for this possibility, the subsequent section should be isolated, and the pressure be monitored during the test, so that the leak rate calculation can be adjusted accordingly. An example is given in Figure 7. In this case, the pig trap is included since this ensures a pressure transmitter in the secondary section, but other arrangements may pertain to a particular piping configuration.

It is possible that the secondary isolations (see Figure 7) will also pass fluid. If it is assumed that all pressure rises are due to the ESDV, then, if the resulting leakage rate is still within bounds, the test may be assumed to be successful. If it the leakage rate is too high for the test to be deemed successful, then the possibility of leakage into the test volume past the secondary isolations should be evaluated before condemning the valve.

Figure 7 **Extended ESDV leak-off test arrangement**



Key

1 Secondary isolation

2 Primary isolation

3 ESDV under test

4 If a pig trap is included, this provides a pressure transmitted in the secondary piping system

5 Secondary piping

6 Primary piping

8.4 Test report

NOTE 1 A sample test report pro-forma is given in Annex H.

Comprehensive details should be recorded during the test. This should include the identifying criteria for the particular valve, the particular test, and the nature of that test. In some cases, provided that adequate data have been recorded, an actual shut-down may be recorded in lieu of a planned test, in which case this should be noted.

The closure time and allowable leak rate defined in the performance standard should be noted, together with the values actually achieved. It is recommended that the performance standard includes a conversion of the allowable leak rate to an allowable pressure increase so that success can be determined on site.

The operating pressure at the time of the test should be recorded. This enables the calculation of leak rate at MAOP, but also clarifies whether the test was carried out at NOP.

The results of the visual inspection should be recorded. If the visual inspection is carried out as a planned maintenance routine (PMR) at another time, the PMR reference should be included, as well as a comment on whether any leaks are observed during the test.

Whilst the procedure for the test will list all isolations to be made, the test report should still confirm for future reference which valves were closed to make the isolations (this is particularly relevant to the secondary piping isolations, where different options might apply).

Because an ESDV is a safety-critical element, it is essential that it closes on demand. The results of the initial demand should therefore be recorded. If the performance standard is not met during this initial demand, this is a reportable incident.

NOTE 2 Attention is drawn to the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995 [11] and to the related HSE guidance [13].

Maintenance is carried out until the valve performs according to the performance standard. The maintenance carried out, and the parameters of the final test, should be recorded for future reference, although this does not represent a satisfactory conclusion of the planned test.

The report of each test should show clearly the result of the initial test, and of subsequent maintenance. Where the initial test is successful, the data can be compared to previous data to look for any trends. These could indicate progressive degradation. Where the test is not successful, both the data, and the interventions necessary, can be trended to ascertain whether major remedial work is required.

9 Operational testing of pig launchers and receivers

9.1 General

Pig launchers and pig receivers, collectively referred to here as pig traps, are part of the pipeline. When they are lined up for launch or receipt they are exposed to the full inventory of the pipeline, and their integrity needs to be assured. Opening a pig trap door can be considered as a break in the containment envelope of the pipeline, and closure regarded as reinstatement following that break in the containment envelope.

A leak test to 1.1 times the maximum allowable operating pressure (MAOP) is recommended before recommissioning following a break in the containment envelope of part of a pipeline system; and if that is not practicable a risk assessment should be performed to establish a safe working practice.

This clause looks at the way in which door integrity can be assured after a break in the containment envelope. It cannot cover all possibilities, but it describes a number of situations, and suggests methods of testing that will normally satisfy the requirements of a risk assessment; however, every case should be evaluated on its own merits.

The integrity of pig traps relies on other activities than testing after a break in the containment envelope, and those activities are also discussed.

9.2 Leak test

The door seal should be tested each time the door is closed.

Most door seals are pressure-activated, i.e. the more pressure that is exerted, the more tightly they seal. For this reason, if the door passes a low pressure test, it is unlikely that it will fail a high pressure test. However, there is a possibility that the seal will go on to fail at high pressure despite having sealed at low pressure, so a high pressure test should still be performed, as a seal failure can have severe consequences.

There might be other seals associated with the door that have been broken and remade; e.g. many traps have a bolt with a tell-tale groove in the thread. The bolt is likely to rely upon a proprietary seal arrangement to achieve containment. If it has not been replaced properly it may fail under high pressure despite sealing at low pressure. A low pressure leak test can check that the seal has been properly activated, but a high pressure leak test is required to test the seal material and all sealing faces.

9.3 Strength test

Pressure tests following breaks in the pressure containment envelope are normally carried out in order to check for leaks, but in the case of pig trap doors, the strength of the door should be checked to ensure that the closure has been properly reassembled.

The structure of the closure is usually tested during the initial pre-commissioning strength test and this does not normally need to be repeated routinely. The design should allow for the likely number of pressure cycles to be seen by the trap, and if the product is corrosive, there should be a corrosion allowance. If the permitted number of pressure cycles is exceeded, or if corrosion goes beyond design limits, the strength of the door should be re-evaluated as a separate exercise.

Most modern doors do not allow full closure unless all components are correctly located; but there are many different closure designs. A risk assessment should be performed that takes into account all ways that a door mechanism could be wrongly closed which could lead to failure. If the risk assessment concludes that it is necessary, a combined strength test and leak test should be performed every time the door is closed.

The main difference between a strength test and a leak test in this case is that additional precautions should be taken in case of door failure. This can affect the area that has to be cordoned off and the procedures for access into the cordoned area during the test.

No general rules can be given for a strength test, as each pig trap requires its own procedure and risk assessment; however, if a strength test is required, it is generally combined with the leak test. If a strength test is to be carried out routinely, the pressure should be kept as low as possible (commensurate with the objectives of the test), to avoid accelerating fatigue damage.

9.4 Test variables

9.4.1 Test pressure

When breaks in the containment envelope of a pipeline system are remade, they should be tested to a pressure above the MAOP to ensure that they will continue to contain the MAOP on recommissioning. PD 8010-2 recommends that any leak testing necessary at the time of construction is carried out at 1.1 times the MAOP; and where practicable, leak tests on pig trap doors should also conform to this criterion.

Pig traps are vessels and usually have pressure relief valves; and there is often no means of isolating the relief valve from the pig trap. If 1.1 times the MAOP would risk the relief valve lifting, then the test pressure should be reduced to 95% of the pressure relief valve setting (provided this is still above the maximum operating pressure).

Sometimes the only high pressure source is the product itself. In this case the door should be tested at the highest pressure available using product. Appropriate measures should be taken to mitigate the risks associated with using product for this test.

9.4.2 Test medium

The purpose of a pressure test is to pre-empt a possible leak during operation; and if there is a leak during the test, the testing medium is released to atmosphere. Pressure testing should therefore normally be carried out using an inert test medium that is known to be safe and that will not harm the environment.

Safety is marginally enhanced if the test medium is a liquid, as pressure drops off more quickly in case of a leak than if a gas is used. If water cannot be used, nitrogen is generally acceptable, provided that suitable precautions are taken and the operators are aware of the risks.

In some circumstances a combination of water and nitrogen may be used. In this case the trap is filled with water, but the pressure is raised using nitrogen from a bottle quad.

If an inert medium is not available, and the test has to be carried out with product, appropriate precautions should be taken to minimize the loss of inventory if there is a leak, and to mitigate both safety and environmental consequences of any leak.

9.4.3 Test period

A leak can be found readily if the door area can be kept dry (test medium liquid) or using a leak detector (test medium gas), and the pressure needs only to be held for a few minutes for that purpose. If very toxic gases are being used, sensitive gas detectors should be set up close to the seals being tested, and these also react very quickly to any release.

All elastomers are subject to creep under load, but elastomers for door seals are designed to minimize creep, and the shape of the seal is designed to accommodate any creep that does take place. If this were not the case, long-term failures would be common. The risk is most significant if there is excessive clearance around the door, and it is quite conceivable that a seal would fail through creep with time if it had to bridge too big a gap. That is one reason why a test pressure above the MAOP is desirable in order to accelerate any such failure.

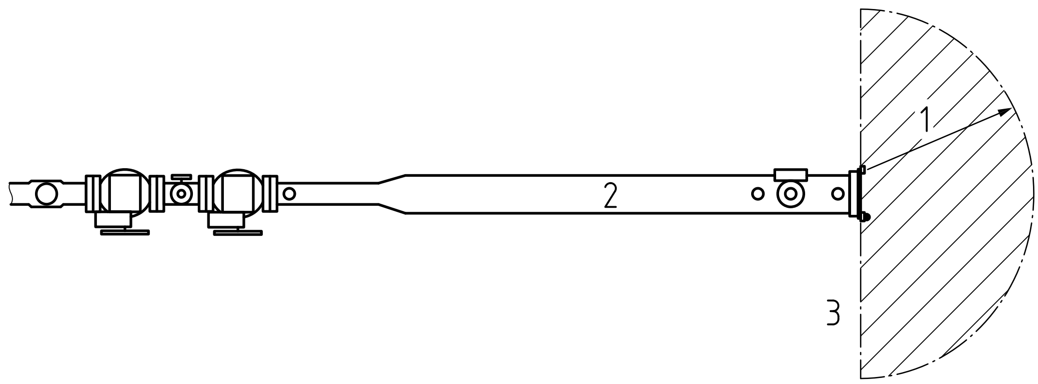
If the test pressure is at least 10% above the maximum operating pressure of the pig trap, it is not necessary to hold the test pressure for longer than the time required to check the seal for leakage. If the test is at operating pressure, the pig trap should be tested for at least 30 min to allow for some initial relaxation of the elastomer; and the pig trap should not be lined up to the full inventory of the pipeline until this hold period has been completed.

9.5 Safety and environmental mitigations

9.5.1 Fluid escape jet

There are direct risks associated with failure of a door seal. Even when testing with water there is the potential for a dangerous high pressure jet that could harm personnel. It is therefore recommended that the area around the door be cordoned off (see Figure 8). It is further recommended that the operator checking for leaks always stands, as far as practicable, to one side. Certain designs of door have a tendency, if they leak, to release jets in certain directions. These directions should be established so that operators can position themselves, as far as practicably possible, to avoid potential jets while checking for leaks.

Figure 8 **Pig trap pressure testing – Restricted area**



Key

1 Distance to be determined by risk assessment

2 Pig receiver

3 Restricted area to be maintained during pressurization

If the gas is toxic, the restricted area should be extended all around the door (including above and below).

9.5.2 Failure of the door locking mechanism

If the door locking mechanism fails during the test, the door could open suddenly, potentially causing a hazard. This is unlikely to happen with modern locking devices, but should be taken into account in any risk assessment.

It is good practice for operators to stand well clear of pig trap doors, and the recommendations in **9.5.1** cover this eventuality in most cases.

9.5.3 Production fluid release – Gas

If a leak occurs with gas in the pig trap, the gas supply should be closed off and, if it is possible to do so safely, the pig trap should be depressurized by lining it up to a controlled vent or flare. This normally happens automatically if the leak is sufficient to activate nearby gas detectors, probably resulting in some kind of executive action by the ESD system.

Two-person operation is recommended, with one person pressurizing the trap and the other watching the door for signs of leakage. At the first sign of a leak, the operator at the pressurization valve should close that valve and either operator should open the vent or flare line if they can do so safely. They should then leave the site until the gas has cleared.

Any leak would be most likely to occur during pressurization, but the operators should be made aware that a leak could occur during the hold period after the test if the pig trap is being tested at operating pressure.

These contingencies should be written into the pig trap operating procedures.

9.5.4 Production fluid release – Liquid

A safe method of depressurizing the pig trap from high pressure should be established. This might require lining up the trap to a vent, a flare, or to drains. In the last case it should be established that the drains can take the full pipeline pressure.

Contingency procedures should be developed for actions in case of a door seal leak when testing with product. If a leak occurs with hydrocarbon liquids in the pig trap, the oil supply should be closed off and the pig trap should be depressurized by lining up to a controlled vent, a flare, or closed drains; but only if it is possible to do so safely.

Two-person operation is recommended, with one person pressurizing the trap and the other watching the door for signs of leakage. At the first sign of a leak, the operator at the pressurization valve should close that valve and either operator should open the vent, flare, or drains line if they can do so safely. Generally this eliminates further risk, but if there is still a risk (e.g. if the liquid tends to vaporize at atmospheric pressure), then the operators should leave the location until the risk has sufficiently reduced. Two-person operation is essential when testing with product, so that one person can remain at the pressurization valve during pressurization, and close the valve immediately if there is a leak.

Any leak would be most likely to occur during pressurization, but the operators should be made aware that a leak could occur during the hold period after the test if the pig trap is being tested at operating pressure.

The maximum volume of liquid likely to escape in a leak should be estimated, and a bunded area provided capable of holding that volume. The extent of the bunded area should take account of the reach of potential liquid jets.

These contingencies should be written into the pig trap operating procedures.

9.6 Risk assessment checklist

9.6.1 Failure mechanisms

Any risk assessment should take into account at least the following failure mechanisms:

- failure of the door seal;
- failure of the door locking system;
- failure of the vessel structure supporting or surrounding the door;
- failure of sealed fittings within the door (e.g. tell-tale).

Many of these failure mechanisms are exacerbated if there is corrosion.

9.6.2 Hazards resulting from failure

The risk assessment should take into account at least the following hazards, many of which are potentially fatal, and some of which could initiate major accidents:

a) fire or explosion from escaped hydrocarbon gas;

b) toxicity, for example if the H_2S content is high;

c) impact from high pressure gas jet;

d) impact from flying debris.

Environmental hazards include:

- oil spill;
- unpleasant or irritating odours, especially applies to onshore or near-shore facilities, or where accommodation is downwind.

9.7 Other integrity activities

*NOTE Risk assessments take benefit from proper integrity management of the pig trap components. The integrity management activities are divided into two categories, which are described in **9.7.1** and **9.7.2**.*

9.7.1 Other integrity activities carried out as a part of pigging operations

Alert operators quickly become aware of problems or deleterious trends during pig trap operations. Their awareness can be emphasized by including a series of checks in the pig trap operating procedures such as:

a) visual inspection of vessel internals for signs of corrosion or scale build-up;

b) visual inspection, and ease of operation, of hinges, door mechanisms (particularly with respect to alignment), and interlocks (where fitted);

c) visual inspection, and reliability of operation, of pig signallers;

d) consistency between, and reliability of, pressure gauges and pressure devices such as pressure activated locks, particularly looking out for blockages in pressure control and measurement systems;

e) visual inspection of door seals (including tell-tale seals if fitted) for any damage or the presence of dirt or debris; it is most important that door seals are kept thoroughly clean and lightly lubricated with a silicon based grease at every door closure (or in accordance with vendor recommendations);

f) effectiveness of vents and bleeds, particularly looking out for blockages;

g) tightness of valves used in the pigging operations.

Operators should be encouraged to report and record any deterioration, however slight, and ensure that it is brought to the attention of the system custodian or other appropriate authority.

Door seals have a finite life and should be replaced routinely in accordance with vendor recommendations.

Door seals, like most elastomeric components, are susceptible to deterioration if not kept correctly. Spares should therefore be stored in accordance with vendor recommendations, and should not be held longer than their stated shelf lives.

9.7.2 Integrity activities carried out independently from pigging operations

Pig traps are subject to the platform integrity management controls. The frequency of inspection is normally based on a risk-based inspection methodology, but should include:

a) general visual inspection of all associated piping and valves, vessels, instruments, instrument tubing, wiring, junction boxes, structural supports, etc. for signs of damage, corrosion or critical coating loss;

b) vendor inspections of critical equipment such as pig trap closures and interlocks;

c) non-destructive examination of piping, vessel shells, and valve bodies;

d) pressure relief valve testing.

All faults or deleterious trends should be reported to the system custodian or other appropriate authority.

9.8 Pressurization after a long period at ambient pressure

Normally the pig trap door is tested immediately after closure, but the pressure is usually reduced following isolation of the trap, and it might be some time before the trap is used again. During that time, if the pressure is low enough, the door seal is likely to have relaxed to the point where its pressure activation has been disturbed.

Subject to an assessment of whether this might mask a small leakage past the isolations, it is recommended that dormant pig traps be left pressurized to (typically) 5 barg to keep door seals activated.

A trap that has been left dormant and fully depressurized for some time should be either:

a) repressurized carefully with product, considering the risk of a leak; initial pressurization should be with nitrogen (if available) to activate the seal before product is introduced; or

b) subject to a full retest prior to repressurization.

In all cases it is recommended that the procedure is subject to a risk assessment.

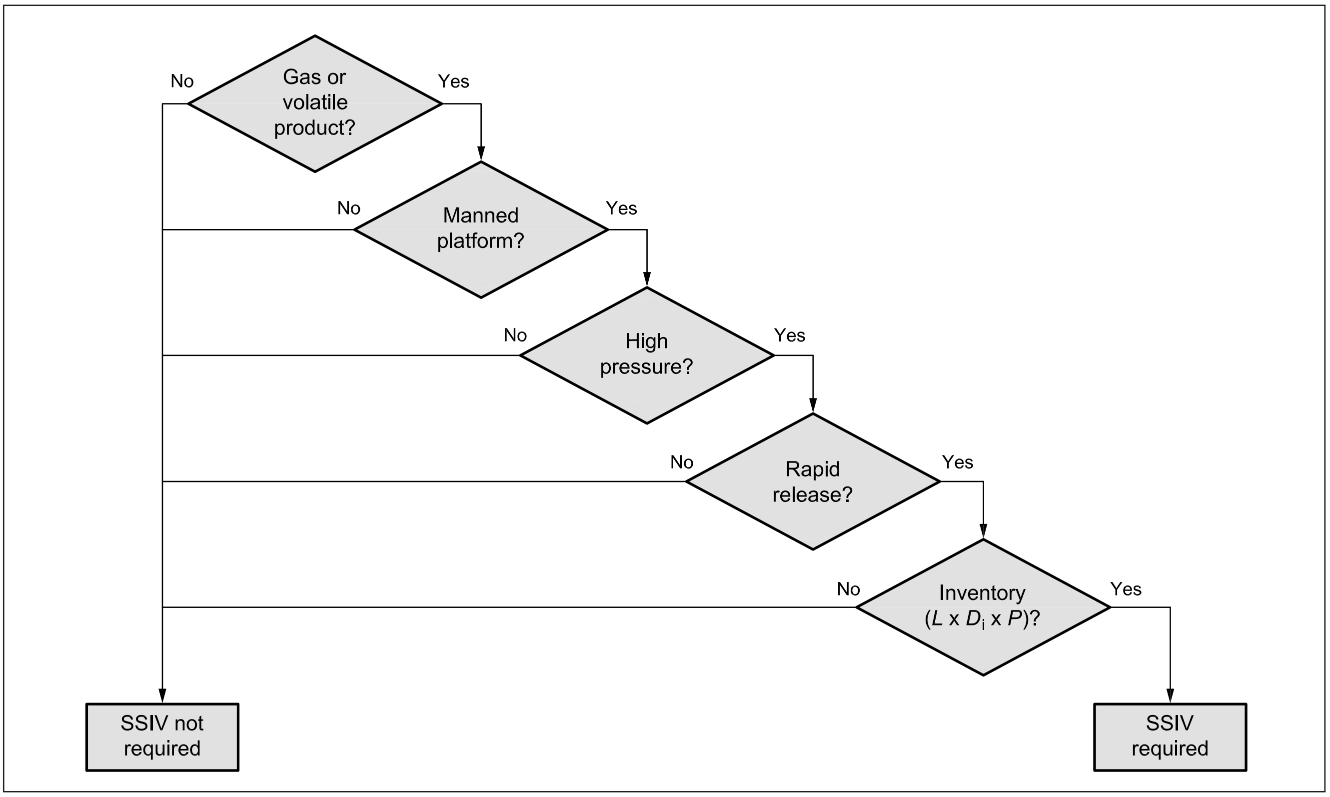
Annex A (informative) Alternative approach to QRA

COMMENTARY ON ANNEX A

A whole-platform QRA is a huge and complex task if the only question is: "do we need an SSIV?" or: "can we lock this existing SSIV open?" This annex investigates the feasibility of a simpler, deterministic approach.

A possible alternative approach to QRA would be to introduce a decision tree as shown in Figure A.1.

Figure A.1 **Possible decision tree**



In this approach, a series of questions is asked, concerning the product, the safety threat, the system pressure, the rate of release and the total inventory. If all the answers are above some deterministic level, then an SSIV is required; otherwise, it is not. The method is a straightforward means for determining the requirement for an SSIV. The problem comes, however, when trying to set the deterministic limits.

- **Gas or volatile product**. If the pipeline is conveying gas, that is straightforward. If it is conveying a volatile condensate or multiphase fluid, then it needs to be determined how the level is to be set.

  NOTE Attention is drawn to the Pipelines Safety Regulations 1996 [8] and to the definition of "dangerous fluids".

- **Manned platform**. All platforms are manned at some time and this might not be the only issue. Some platforms act as the hub to a number of third parties: loss of the hub could carry a serious cost impact in terms of lost revenue, or even claims for loss of revenue by others.
- **High pressure**. It needs to be determined at what level pressure becomes "high". For subsea tie-backs, it could be based upon the closed-in tubing head pressure or the normal flowing tubing head pressure. Pressure alone is not the only issue since it is a factor in the inventory of a high-pressure gas line.

- **Rapid release**. Fire risk assessments deal with release rates by looking at a range of hole sizes along with the other variables so that a single rate can be synthesized for an unknown event and used as a go/no go filter.
- **Inventory ($L \times D_i \times P$)**. The go/no go limit should be evaluated.

It is possible to define some simple rules, such as: "a gas pipeline has to be fitted with an SSIV", or "a crude oil pipeline does not require an SSIV". Between these two extremes, however, is a large grey area, and no deterministic rules can be easily developed to govern it, especially when alternative control measures (see **4.2.3**) also have to be taken into account. Hence the QRA/cost-benefit analysis, as described in **4.2.2**, is the preferred approach.

Annex B (informative) Pro-forma for selection of high pressure in-line isolation plugs

Figure B.1 gives a pro-forma for the selection of isolation plugs.

NOTE The questions in this annex have been compiled from a number of sources. The annex aims to be comprehensive, but some issues relevant to a particular task might not have been captured.

Figure B.1 **Pro-forma for the selection of isolation plugs** *(1 of 4)*

General configuration

These questions refer to the piggability of the pipeline from end to end unless the tool has to be pigged out in reverse to the way it was pigged in. In these circumstances, it is imperative to ensure that the pig launcher is suitable, or can be reconfigured, as a pig receiver.

a) Outer diameter (OD) . . . .

b) Wall thickness (WT) . . . .

c) Internal diameter (ID) . . . .

d) Any ID variations along length . . . .

e) Ovality: note that the bore clearance of plugs tends to be less than with conventional pigs to facilitate wall contact at the set location; hence excessive ovality can prevent the passage of a plug. . . . .

f) Smallest bend(s) along the route: by radius, by ID: for the same reasons as (e) above, tight bends can prevent the passage of a plug. . . . .

g) Any non-standard configurations: e.g. mitre bends, known dents . . . .

h) Details of all:
1) Valves: including type(s) and confirmation that they are full bore . . . .
2) Tees, wyes: including whether they are barred, piggable, etc. . . . .

i) Any connectors, couplers, joints, intrusive pig signallers, etc., that could impede passage . . . .

j) Material . . . .

k) Does the pipeline cross national borders? (Can lead to a number of issues.) . . . .

Note that, if a pipeline can be pigged from end to end, then it might be advisable to run a calliper tool prior to specifying the isolation task. Depending upon the pipeline service, cleaning runs might be required first. In some cases, the nature of the initial problem (e.g. a valve jammed part-open) might impede end-to-end pigging for cleaning or measurement.

Figure B.1 **Pro-forma for the selection of isolation plugs** *(2 of 4)*

Configuration at set location

If any "General configuration" answers differ at the set location, this should be flagged up. In addition, the following should be defined.

a) Length of straight section . . . . .

b) Pipe manufacture: seamless, welded . . . . .

c) Pipeline design code . . . . .

d) Any internal coating, cladding, liner, etc. . . . . .

e) Any local WT/ID variations . . . . .

f) Any local anomalies (e.g. wall thinning) . . . . .

g) Internal condition – scale, wax, groove corrosion, etc.: note that any of these surface contaminants can affect the quality of locking in place and/or of the seal achieved; in addition, wax can invade the mechanical components of the tool, impairing, for example, the pressure sensors, or the recovery of the slips into their receptacles on release (which could prevent pigging out) . . . .

h) Pipeline buried . . . . .

i) Weight coat applied (in which case, thickness, density) . . . . .

j) Close proximity to any tees, wyes, valves, etc. . . . . .

k) External obstructions (e.g. clamps, guides, doubler plates), or general condition, that might hinder through-wall communication . . . . .

l) Will the intervention itself introduce restrictions to recovery . . . . .

m) Is an intrusive pig signaller fitted in the section (in which case, which type) . . . . .

n) Specific location – topsides/subsea; horizontal, vertical, at an angle (specify) . . . . .

o) Water depth at set location . . . . .

p) Accuracy of positioning required – relates to driving medium (see *Operating conditions*) since precision reduces with compressibility of fluid . . . . .

q) Intended tracking method . . . . .

r) Pigging distance to isolation location . . . . .

s) Pigging distance to retrieval location . . . . .

t) Is the tool to be recovered in the launcher . . . . .

u) Optimum transit speed (or acceptable range). . . . .

The executive operator should anticipate providing all relevant Isometric and piping and instrumentation drawings: the better the information, the more likely the job will run smoothly. The executive operator should consider conducting a local inspection of the set location, to include activities such as wall thickness checks, prior to completing the questionnaire above.

Figure B.1 **Pro-forma for the selection of isolation plugs** *(3 of 4)*

Pig traps

Confirm that the launcher, and receiver (as applicable), are in place and commissioned (or that temporary facilities will be installed), and provide details including relevant isometric and piping and instrumentation drawings. Also provide a lifting and handling plan showing aids and constraints.

a) Length of launcher/receiver (individual barrels, if applicable) . . . . .

b) Diameter of launcher/receiver (individual barrels, if applicable) . . . . .

c) Dimensions of launcher/receiver working area . . . . .

d) Facilities for handling tool into/from launcher/receiver: cranes, rigging points, etc. . . . . .

e) Door details (note: modifications might be required for a tethered tool) . . . . .

f) Details of pipework at launcher/receiver . . . . .

g) Location of balance line tie-in connections . . . . .

h) Details of location
- Onshore, offshore, subsea? . . . . .
- Normally manned, unmanned? . . . . .

i) Confirm when integrity was last assessed. . . . . .

If a launcher has to be used as a receiver also (e.g. because the intervention has introduced an obstruction in the bore), it is necessary to confirm that it is suitable, or can be reconfigured, for this purpose.

Note regarding item g): the plug geometry might be somewhat different to that of the pigs that are usually handled. Therefore it is important to ensure that the plug does not isolate the balance line because, if the pipeline pressure is higher than the trap pressure when the pig trap valves are opened, this would drive the plug back into the trap. In the same way, if an external medium, such as nitrogen, is to be used,

The tie-in needs to be towards the back of the trap so that the pressure is exerted fully behind the plug.

It is important to ensure that all isolation valves have been inspected and tested well in advance of the intervention, and that the launcher and receiver are confirmed as ready for use. It is advisable to ensure that key spares (including door seals) are available prior to mobilizing for the work.

Pigging history

Provide the dates of most recent previous pigging (as applicable):

a) Intelligent pig run . . . . .

b) Cleaning pig run . . . . .

c) Calliper/gauging run . . . . .

d) All previous isolation tool deployments. . . . . .

Flag up any problems or issues arising from any of these runs: note that, in many cases where jobs have not run smoothly, it was the pigging, rather than the plugging, and especially the release and pigging out, that caused the problems, so it is important to be conscious of any previous issues.

Figure B.1 **Pro-forma for the selection of isolation plugs** *(4 of 4)*

Operating conditions

a) Operating temperature; or temperature range; or profile along route . . . . .

b) Operating pressure . . . . .

c) Isolation pressure required . . . . .

d) Test pressure (if applicable) . . . . .

e) Any simultaneous operations that could affect line pressure . . . . .

f) Duration of isolation hold . . . . .

g) Overall duration of intervention . . . . .

h) Number of isolation plugs anticipated for task . . . . .

i) Block and bleed requirements . . . . .

j) Shut-in constraints (e.g. access to vent/flare for blow-down) . . . . .

k) Production fluid characteristics:
- Sour . . . . .
- Mercury . . . . .
- Naturally occurring radioactive material . . . . .

l) Intended pigging medium:
- N_2 . . . . .
- Liquid: product, diesel, water, other . . . . .
- Production gas . . . . .

m) Pump type, characteristics. . . . . .

NOTE Items (l) and (m) may be under the control of the contractor.

Annex C (informative) Sample failure mode listing

Table C.1 may be used as the basis for a failure modes and effects analysis in relation to a plugging task. Individual operator preference, and different task requirements, mean that this is likely to require modification prior to use.

Table C.1 **Failure modes for pipeline plugging operations** *(1 of 5)*

Activity	Function	Failure mode	Failure cause	Failure cause (level 2)
Delivery of tool(s)	Provision of one or more plugs at the insertion location	Damage in transit	Inadequate protection Incorrect lift Bad weather	Inadequate protection
		Non-availability	Still on previous task Waiting on components Waiting on weather	Previous faults/damage
Handling of tool(s)	Manoeuvring tool from transit packaging to launcher area	Damage during handling	Incorrect rigging Inadequate deck area Obstructed access to pig trap	
Cleaning pipeline	Ensuring the pipe wall is in a suitable condition to achieve a good seal	Pipeline not piggable	No facilities due to intervention requirement	
		Cleaning unsuccessful	Persistent contaminant Frequent platform shut-downs Inadequate pig type	Wax deposition
		Stuck pig	Contaminants on pipe wall Unknown obstruction	Scale Wax Dent Valve not fully open
Measuring pipeline	Confirming that ID, ovality, etc. will not obstruct passage of plug	Pipeline not piggable	No launch/retrieval facilities due to intervention requirement	Partial blockage
		Stuck calliper tool	Contaminants on pipe wall Unknown obstruction	Scale Wax Dent Valve not fully open
Testing/calibration on site	Ensuring all plug systems are fully functional prior to launch	Plug fails tests	Faulty components Damage during delivery Human error Incorrect/missing interfaces	
Loading/insertion	Introduction of plug into launcher	Damage during insertion	Incorrect rigging Inadequate deck area Obstructed access to pig trap	

Table C.1 **Failure modes for pipeline plugging operations** *(2 of 5)*

Activity	Function	Failure mode	Failure cause	Failure cause (level 2)
		Plug leaves launcher unplanned	Incorrect valve operations Loss of control (vertical launcher) Human error	
		Plug sticks	Incorrect dimensions supplied	
Establishing isolation	Running the plug to set location, locking in place and setting the seals	Loss of communication	Battery failure	
			Power system failure	
			Component failure	
			Excess pipeline burial	Excessive signal attenuation
			Incorrect location (tracking)	
		Loss of tracking	Battery failure	
			Power system failure	
			Component failure	
			Antenna failure	
			Excess pipeline burial	Excessive signal attenuation
			ROV system failure	
		Plug stuck en route	Inadequate bore	
			Excess ovality	
			Excess contaminants	
			Loss of differential pressure	Pipe wall corrosion Cup failure
			Unexpected blockage	Dent Valve not fully open Tight radius bend
			Inadequate drive pressure	
			By-pass across tee	

Table C.1 **Failure modes for pipeline plugging operations** *(3 of 5)*

Activity	**Function**	**Failure mode**	**Failure cause**	**Failure cause (level 2)**
		Plug overshoots set location	Lack of flow control Irregular flow High gas content (compressibility)	
		Plug fails to lock (slips fault)	Communications failure Control systems failure Mechanical failure Pipe wall contamination Pipe wall corrosion Material inconsistency	
		Plug fails to seal (packer fault)	Communications failure Control systems failure Mechanical failure Pipe wall contamination Pipe wall corrosion Pipeline yields locally	 Stress analysis not carried out
Proof of isolation	Demonstrating that a seal has been established that can be relied on	Seal cannot be confirmed	Pressure sensors fail Pressure pipework failure Communications failure Plug not set	
		Seal not achieved	Pipe wall corrosion Pipe wall contamination Damage to seal/packer	
		Test pressure not achieved	Inadequate pump/compressor Relief valves incorrectly set	
Monitoring maintenance of isolation (pressure monitoring)	Demonstrating that the seal is being maintained	Pressure monitoring failure	Pressure sensors fail Pressure pipework failure Communications failure	
		Seal not holding	Seal/packer degradation	Unsuitable material Unexpected wear during run in Excess duration of hold

Table C.1 **Failure modes for pipeline plugging operations** *(4 of 5)*

Activity	Function	Failure mode	Failure cause	Failure cause (level 2)
Release of isolation	Un-setting the seals, unlocking the slips, pigging out	Seal/packer does not release	Communications failure	
			Control systems failure	
			Mechanical failure	
			Stuck to pipe wall contaminants	
		Slips do not release	Communications failure	
			Control systems failure	
			Mechanical failure	
			Gas permeated into hydraulic fluid	
			Embedded in pipe wall	
			Wax/hydrate in receptacle	
		Plug embedded	Wax	
			Hydrate	
			Sediment	
		Loss of tracking	Battery failure	
			Power system failure	
			Component failure	
			Antenna failure	
			Excess pipeline burial	Excessive signal attenuation
			ROV system failure	
		Loss of communication	Battery failure	
			Power system failure	
			Component failure	
			Excess pipeline burial	Excessive signal attenuation
			Incorrect location (tracking)	

Table C.1 **Failure modes for pipeline plugging operations** *(5 of 5)*

Activity	**Function**	**Failure mode**	**Failure cause**	**Failure cause (level 2)**
		Plug stuck pigging out	Inadequate bore	
			Excess ovality	
			Excess contaminants	
			Loss of differential pressure	Pipe wall corrosion Cup failure
			Unexpected blockage	Dent Valve not fully open Tight radius bend
			Inadequate drive pressure	
			By-pass across tee	
			Collision with other plug or pigs	
Recovery of tool(s)	Manoeuvring tool from the pig receiver	Damage during handling	Incorrect rigging	
			Inadequate deck area	
			Obstructed access to pig trap	
			Plug jams in pig trap	
			Recovery issues – vertical receiver	

Annex D (informative) Pro-forma sheets for pipeline integrity data exchange: main data sheet

A typical main data sheet for pipeline integrity data exchange is shown in Figure D.1.

The main data sheet is completed by the relevant operators prior to commissioning of a new line, or when the pro-forma is adopted. It is envisaged that this sheet will not be modified frequently (apart from revisions of key document references or changes of key personnel). However, it may be modified if, for example, the chemical injection strategy has to be changed in the light of operating experience. Any revisions to the sheet need to be agreed by all the operators to ensure that they are aware of the changes.

The main data sheet could be made a controlled document or could be embedded in a controlled interface document.

The sheet identifies key parameters of the pipeline (length, pressure and temperature limits, etc.) and makes provision for a simple sketch, which may be used to identify the limits of responsibility, and to highlight key features. An example sketch (of a hypothetical pipeline) is included in the example main data sheet in Annex F; the level of sophistication of the sketch will depend in part on the complexity of the pipeline system.

The remainder of the first section contains descriptions of the system in terms of corrosion monitoring, chemical injection, key design features and (external) protection in place. It also defines the agreed date for the annual report.

The second section lists key documents and key points of contact.

Figure D.1 **Pro-forma sheets for pipeline integrity data exchange: main data sheet** *(1 of 2)*

If the data sheet is revised, the revised version should be agreed by all the executive and site operators. Where numeric data are to be entered, the units should be explicitly stated to avoid ambiguity.			
PL No:	From:	To:	KP0 at:
Service:		Commissioning date:	Length:
MAOP:	NOP (if applicable):	T_{max}:	T_{min}:
Sketch map [to identify demarcations between pipeline operator (PSR) and other operators]: *Use colours or line styles to identify responsibilities of individual operators – see example in Annex F.*			
Corrosion monitoring in place (e.g. coupons, probes, FSM, with locations):			
Chemical injection strategy (e.g. corrosion, scale, or wax inhibitors, scavengers, biocide, anti-emulsion agents):			
Key design features (e.g. pipe-in-pipe, bundle, snake-lay, HIPPS):			
Protection description (e.g. trenched, mechanically backfilled, naturally backfilled, rock-dumped, with relevant lengths):			
Reporting date (each year):			

Figure D.1 **Pro-forma sheets for pipeline integrity data exchange: main data sheet** *(2 of 2)*

Key documents			
Title	Doc no.	Rev	Date

Key points of contact			
Name	Job title	Email address	Tel no.

Annex E (informative) Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet

A typical annual data exchange sheet is shown in Figure E.1.

The structure of this sheet is a series of rows, one for every parameter or system relevant to pipeline system integrity. Each row asks for specific information (e.g. minimum, average and maximum of a variable, or a test date), and then leaves a space for any further comments. At the right hand are two columns. The first is entitled "Plot?" or "Rpt?": if the information provided is supplemented by a plot (e.g. operating pressure) or a report (e.g. intelligent pig summary report), a tick can be placed in the relevant box. The second is entitled "Responsible": this is to be agreed by all parties when the sheets are first set up, and defines who should provide which information.

The "Criticality" box (at the top of the first page) is intended to contain the outcome of the risk assessment carried out by the executive operator, and is to be agreed by all operators. The "Revision of criticality" box on the final page is intended to contain comments on any changes to the risk assessment (e.g. in response to an intelligent pig run), or state that the risk assessment is unchanged (for continuity purposes).

The inspection records are defined for the "First end" and "Second end". Thus the sheet can be used for a full data exchange (the supplier of information being defined in the right hand column). Alternatively, the sheet may be used only for the non-operator(s) to supply information to the executive operator, in which case some of the rows may be deleted. (It is then assumed that the executive operator will make the full integrity report available to the other parties.)

Rows such as "Water cut", "Dewpoint", "O_2" or "Caisson or J-tube annulus" may be deleted depending upon the service and configuration of the pipeline in question. It is expected that the contents of the sheet, and the responsible person for the supply of data, will be agreed at the same time as the main data sheet is agreed.

At the end of the sheet is a box for "Date next report due". This is defined in the main data sheet, but confirming it here ensures that all parties are aware of the deadline they are working to.

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(1 of 6)*

If the data sheet is revised, the revised version should be agreed by all the executive and site operators. Where numeric data are to be entered, the units should be explicitly stated to avoid ambiguity.			
PL No:	From:	To:	Criticality:

Notes:
(1) enter values for the past 12 months.
(2) put a tick in the right hand column if a supporting data plot or report is provided.

Operating pressure	Min:	Ave:	Max:	Comments (e.g. degree of cycling):	Plot?	Responsible
Operating temperature	Min:	Ave:	Max:	Comments:	Plot?	Responsible
Water cut	Min:	Ave:	Max:	Comments (e.g. produced versus injected):	Plot?	Responsible
Corrosion rate (int)	Min:	Ave:	Max:	Comments (e.g. source of data):	Plot?	Responsible
Dewpoint (*gas lines*)	Min:	Ave:	Max:	Comments (e.g. compare with limit):	Plot?	Responsible
H_2S	Min:	Ave:	Max:	Comments (e.g. compare with limit):	Plot?	Responsible
CO_2	Min:	Ave:	Max:	Comments (e.g. compare with limit):	Plot?	Responsible
O_2 (*WI lines*)	Min:	Ave:	Max:	Comments (e.g. compare with limit):	Plot?	Responsible

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(2 of 6)*

Corrosion inhibitor	Injected (Y/N)?	Comment on achieved versus required:	Plot?	Responsible
Scale inhibitor	Injected (Y/N)?	Comment on achieved versus required:	Plot?	Responsible
Wax inhibitor	Injected (Y/N)?	Comment on achieved versus required:	Plot?	Responsible
Other chemicals	Injected (Y/N)?	Comment on achieved versus required:	Plot?	Responsible
SRB testing	SRB detected?	Comments:	Rpt?	Responsible

Operational pigs	Date last run:	Comments:	Rpt?	Responsible
	Date next run:			
Intelligent pig	Date last run:	Comments:	Rpt?	Responsible
	Date next run:			

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(3 of 6)*

First end

ESDV	Date last test:	Comments:	Rpt?	Responsible
	Date next test:			
SSIV	Date last test:	Comments:	Rpt?	Responsible
	Date next test:			

Topsides pipework (incl. pig trap)	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Riser, caisson, J-tube, down to splash zone	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Riser, caisson, J-tube, splash zone to seabed	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Caisson or J-tube annulus (as applicable)	Inspection date:	Comments on sampling and dosing:	Rpt?	Responsible
	Next insp. date:			
Pipeline in 500 m zone	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Main line	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(4 of 6)*

Second end

Pipeline in 500 m zone	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Caisson or J-tube annulus (as applicable)	Inspection date:	Comments on sampling and dosing:	Rpt?	Responsible
	Next insp. date:			
Riser, caisson, J-tube, splash zone to seabed	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Riser, caisson, J-tube, down to splash zone	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			
Topsides pipework (incl. pig trap)	Inspection date:	Comments:	Rpt?	Responsible
	Next insp. date:			

SSIV	Date last test:	Comments:	Rpt?	Responsible
	Date next test:			
ESDV	Date last test:	Comments:	Rpt?	Responsible
	Date next test:			

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(5 of 6)*

SRB testing	SRB detected?			Comments:	Rpt?	Responsible
Corrosion rate (int)	Min:	Ave:	Max:	Comments (e.g. source of data):	Plot?	Responsible

Interventions carried out	Description of any interventions:	Rpt?	Responsible
Ongoing concerns	Identify any outstanding issues:	Rpt?	Responsible
Future pigging strategy	Define any changes to operational or inspection pig strategy:	Rpt?	Responsible
Revision of criticality	Define any changes or state unchanged:	Rpt?	Responsible

Figure E.1 **Pro-forma sheets for pipeline integrity data exchange: annual data exchange sheet** *(6 of 6)*

Date next report due		

Completed on behalf of (print company name):	Completed by (print name):	Signature:	Date:	Contact tel/email:

Annex F (informative) Pro-forma sheets for pipeline integrity data exchange: example of completed main data sheet

An example of a completed main data sheet for pipeline integrity data exchange is shown in Figure F.1.

Figure F.1 **Pro-forma sheets for pipeline integrity data exchange: example of completed main data sheet** *(1 of 2)*

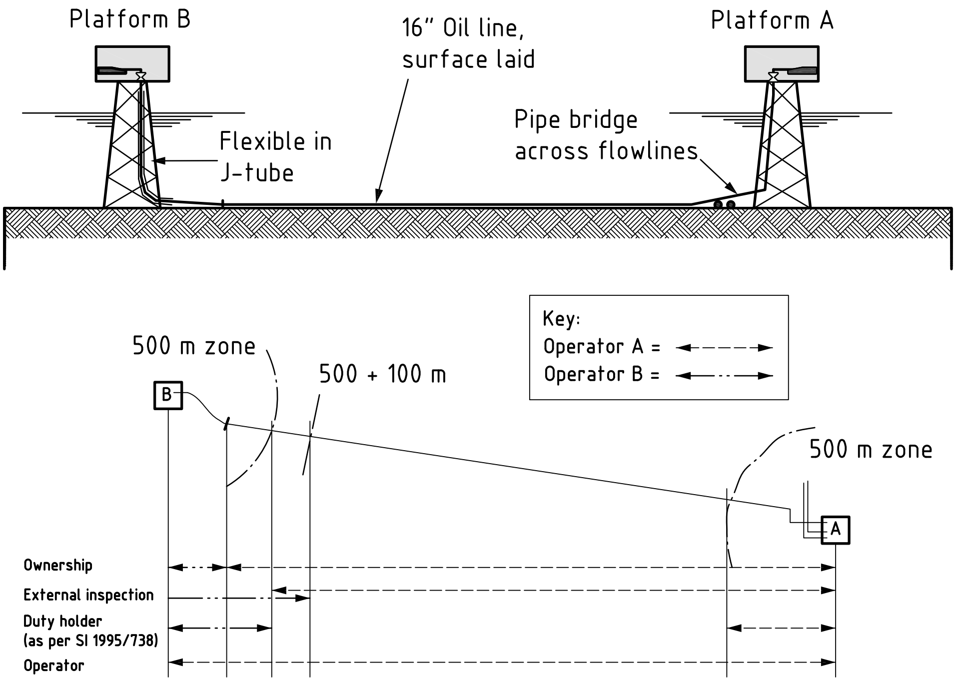
<table>
<tr><td colspan="4">If the data sheet is revised, the revised version should be agreed by all the executive and site operators. Where numeric data are to be entered, the units should be explicitly stated to avoid ambiguity.</td></tr>
<tr><td>PL No:
4321</td><td>From:
A</td><td>To:
B</td><td>KP0 at:
A</td></tr>
<tr><td colspan="2">Service:
16" Oil Export</td><td>Commissioning date:
20/11/1992</td><td>Length:
23 km</td></tr>
<tr><td>MAOP:
110 barg</td><td>NOP (if applicable):
95 barg</td><td>T_{max}:
70 °C</td><td>T_{min}:
–20°C</td></tr>
<tr><td colspan="4">Sketch map (to identify demarcations between pipeline operator (PSR) and other operators):

</td></tr>
<tr><td colspan="4">Corrosion monitoring in place:
Probe at A, upstream of ESDV
Coupon at B, downstream of receiver tee, to be extracted annually</td></tr>
<tr><td colspan="4">Chemical injection strategy:
Corrosion inhibitor (XYZ) to achieve 140 ppm water content</td></tr>
</table>

Figure F.1 **Pro-forma sheets for pipeline integrity data exchange: example of completed main data sheet** *(2 of 2)*

Key design features: Tie-in spool on lattice bridge at A (crosses PQR flowlines) At B, flexible riser pulled up J-tube, extends to tie-in 30 m from platform
Protection description: Pipeline laid on seabed, 40 mm concrete coat over CTE Concrete "dog kennel" dropped object protection over flexible at B
Reporting date (each year): March 31st

Key documents			
Title	Doc no.	Rev	Date
Interface document			
Table A			
Major accident prevention document (MAPD)			
Emergency response procedures			
Operating procedures			
Pipeline summary data manual			

Key points of contact			
Name	Job title	Email address	Tel no.

Annex G (informative) Caisson and J-tube risk assessment

With reference to PD 8010-4:2012, **7.2**, and specifically to Table 1 therein, Table G.1 below provides examples for developing a risk assessment for caissons and J-tubes. The table has four sub-sections: general, top section, splash zone and bottom section.

Table G.1 **Caisson and J-tube risk assessment** *(1 of 3)*

Zone	Process	Due to…	Leading to…	Probability	Consequence	Criticality
General	Riser internal corrosion	Product	Loss of containment to annulus (loss to environment on riser failure)			
	Clamps, guides	Corrosion of bolts	Loss of support			
	Marine growth	Natural process	Increased hydrodynamic loading			
	Lack of mixing of corrosion inhibitor	Spacers, baffle plates	Riser external corrosion and/or caisson/J-tube internal corrosion			
Top section	Riser external corrosion	Coating deficiency	Loss of containment to annulus			
		Dissimilar metals, etc.	Loss of containment to annulus and/or environment			
	Caisson/J-tube internal corrosion	Coating deficiency	Loss of annulus integrity (loss to environment on riser failure)			
	Caisson/J-tube external corrosion	Coating deficiency	Loss of annulus integrity (loss to environment on riser failure)			
	Seal failure	Differential expansion	Loss of annulus integrity (loss to environment on riser failure)			
		Elastomer degradation	Loss of annulus integrity (loss to environment on riser failure)			
	Sensor failure	Reliability issues	Alarm malfunction – no warning of high/low pressure, etc.			
	Vent system blocked	Corrosion product/untested	Overpressure of caisson/J-tube (catastrophic failure on riser failure)			
	Purge/pressurization system failure	Reliability issues	Water in annulus not identified (greater threat of riser failure)			

Table G.1 **Caisson and J-tube risk assessment** *(2 of 3)*

Zone	Process	Due to…	Leading to…	Probability	Consequence	Criticality
Splash zone	Riser external corrosion	Coating deficiency (e.g. abrasion in J-tube)	Loss of containment to annulus			
		Coating deficiency (e.g. field joints in caisson)	Loss of containment to annulus			
		Inadequate corrosion inhibition (tidal)	Loss of containment to annulus			
		Anodes depleted, inadequate throw	Loss of containment to annulus			
	Caisson/J-tube internal corrosion	Coating deficiency (e.g. abrasion in J-tube)	Loss of annulus integrity (loss to environment on riser failure)			
		Inadequate corrosion inhibition (tidal zone)	Loss of annulus integrity (loss to environment on riser failure)			
		Anodes depleted, inadequate throw	Loss of annulus integrity (loss to environment on riser failure)			
	Caisson/J-tube external corrosion	Coating deficiency (including special coatings)	Loss of annulus integrity (loss to environment on riser failure)			
		Anodes depleted	Loss of annulus integrity (loss to environment on riser failure)			
	Caisson/J-tube external damage	Boat impact	Denting of caisson/J-tube; possible loss of annulus integrity			
		Dropped objects	Coating damage (see above)			

Table G.1 **Caisson and J-tube risk assessment** *(3 of 3)*

Zone	Process	Due to…	Leading to…	Probability	Consequence	Criticality
Bottom section	Riser external corrosion	Coating deficiency (e.g. abrasion in J-tube)	Loss of containment to annulus			
		Coating deficiency (e.g. field joints in caisson)	Loss of containment to annulus			
		Dissimilar metals, etc	Loss of containment to annulus and/or environment			
		Inadequate corrosion inhibition (seal leak in J-tube)	Loss of containment to annulus			
	Caisson/J-tube internal corrosion	Coating deficiency (e.g. abrasion in J-tube)	Loss of annulus integrity (loss to environment on riser failure)			
		Dissimilar metals, etc. – caisson base plate	Loss of annulus integrity (loss to environment on riser failure)			
		Inadequate corrosion inhibition (seal leak – J-tube)	Loss of annulus integrity (loss to environment on riser failure)			
	Caisson/J-tube external corrosion	Coating deficiency	Loss of annulus integrity (loss to environment on riser failure)			
		Anodes depleted	Loss of annulus integrity (loss to environment on riser failure)			
	Caisson seal failure	Differential expansion	Loss of annulus integrity; dilution of corrosion inhibition			
		Degradation of grout	Loss of annulus integrity; dilution of corrosion inhibition			
	J-tube seal failure	Poor design	Loss of annulus integrity; dilution of corrosion inhibition			
		Poor installation	Loss of annulus integrity; dilution of corrosion inhibition			
		Riser expansion	Loss of annulus integrity; dilution of corrosion inhibition			
	Sampling/replenishment line blockage	Corrosion product; congealed chemicals	Inability to inhibit annulus; corrosion threat			
	Caisson/J-tube external damage (including bridges)	Dropped objects	Denting/piercing – loss of annulus integrity			

Annex H (informative) Pro-forma for ESDV test report

A pro-forma for ESDV test reports is shown in Figure H.1.

Figure H.1 **Pro-forma for ESDV test report**

Tag No:	Pipeline OD:			Pipeline No:		
MAOP:	Pipeline service:					
Date of test:	Time of test:			Procedure Ref:		
Type of test (*tick relevant box*):	Partial closure		Full closure		Full & leak-off	
If this is recording an operational shut-down in lieu of scheduled test, note circumstances:						
Measured operating pressure at time of test:						
Report on visual inspection:						
Valves closed (tags):						
Results of first initiation				Performance standard		
Control system response time:						
Time to close:						
Measured pressure build-up (or leak) rate:						
Pressure increase in secondary cavity:						
Result of initial test (*tick relevant box*):	Satisfactory			Unsatisfactory		
If initial test unsatisfactory, identify all maintenance activities and intermediate tests carried out (*continue on reverse of this sheet, if necessary*):						
Results of final/satisfactory test (*if initial test unsatisfactory*)						
Control system response time:						
Time to close:						
Measured pressure build-up (or leak) rate:						
Pressure increase in secondary cavity:						
Name & signature of tester	Print			Sign		
Name & signature of approver	Print			Sign		

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