FOREWORD

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F) Pipelines and Risers
G) Asset Operation
H) Marine Operations
J) Wind Turbines

**Amendments and Corrections**

This document is valid until superseded by a new revision. Minor amendments and corrections will be published in a separate document normally updated twice per year (April and October).

For a complete listing of the changes, see the “Amendments and Corrections” document located at: http://webshop.dnv.com/global/, under category “Offshore Codes”.

The electronic web-versions of the DNV Offshore Codes will be regularly updated to include these amendments and corrections.
Acknowledgement

This Recommended Practice has been developed in close cooperation with the industry. The basis for the Recommended Practice was developed within the recently completed Joint Industry Project (JIP) titled 'Integrity Management of Submarine Pipeline Systems'. The project was performed by DNV in co-operation with its JIP partners and was funded by the JIP.

In addition to the feedback from the JIP members, the recommended practice has been circulated on extensive internal and external hearing.

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Following the termination of the Joint Industry Project, this material was used to develop DNV's Recommended Practice, DNV-RP-F116, which will be linked to the DNV Offshore Standard for Submarine Pipeline Systems DNV-OS-F101.

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1. General

1.1 Introduction

This recommended practice provides requirements, as given in DNV-QS-F101 and recommendations for managing the integrity of submarine pipeline systems during the entire service life.

1.2 Objectives

The objectives are to:

— ensure that the operation of submarine pipeline systems are safe and conducted with due regard to public safety, environment and properties
— present more detailed requirements based on these general requirements
— present general requirements reflecting the parts of the DNV offshore standard DNV-QS-F101 that cover integrity management
— provide guidance on how to comply with the requirements
— serve as a guideline for operators and suppliers.

1.3 Scope and application

This recommended practice gives guidance on how to establish, implement and maintain an integrity management system.

The main focus is on the Integrity Management Process; i.e. the combined process of threat identification, risk assessment, planning, monitoring, inspection, and repair.

This recommended practice is applicable to rigid steel submarine pipeline systems, and its associated pipeline components, as defined in DNV-QS-F101 Sec.1 C336 and C287, and its Appendix F. It focuses on structural/containment failures, and threats that may lead to such failures.

The integrity management system described herein will also be applicable to rigid risers, however, for details; reference is given to DNV-RP-F206 ‘Riser Integrity Management’ /2/, which also covers flexible risers.

1.3.1 Submarine pipeline system

A submarine pipeline system extends to the first weld beyond:

— the first valve, flange or connection above water on platform or floater
— the connection point to the subsea installation (i.e. piping manifolds are not included)
— the first valve, flange, connection or isolation joint at a landfall unless otherwise specified by the onshore legislation.

The components mentioned above (valve, flange, connection, isolation joint) includes also any pup pieces, i.e. the submarine pipeline system extends to the weld beyond the pup piece.

Guidance note:
In case of branch-off connections to other pipeline systems, which may introduce a change in the Operator responsibility, the pipeline system extends to the first valve beyond the branch connection.

A submarine pipeline system includes (main/trunk) transport lines and in-field lines, and consists of export lines (oil & gas), production lines (oil & gas) and utility lines (gas injection, gas lift, water injection, chemicals).

1.3.2 Pipeline components

Pipeline components within the above limits are integrated parts of the pipeline system, e.g. flanges, tees, bends, reducers, spools and valves.

Intervention and repair components such as e.g. repair clamps shall also be included.

1.3.3 Protective means

Typical protective means included in the scope to ensure the integrity of the submarine pipeline system are:

— internal protection means – cladding, internal lining, internal coating, internal HDPE liner, chemical treatment, direct electrical heating (DEH)
— external protection means – coating/concrete, galvanic anodes, bend restrictors, support structures (natural and/or man-made), protective structures, trenches (covered/not covered), GRP covers, rock dumpings, mattresses. Should cover both the pipeline and the pipeline components.
— rock dumping or mattresses in connection with crossings
— isolation joints.

Guidance note:
In this recommended practice, ‘protective means’ are defined as means that are implemented as part of the design in order to mitigate threats to the system. This can for instance be introduction of internal lining to prevent internal corrosion or GRP covers to reduce the risk of third party damage.

1.3.4 Onshore part of the submarine pipeline system

A submarine pipeline system is defined to end at the weld beyond the first valve/flange onshore or at the pig trap. This implies that a part of the pipeline system can be located onshore. This part of the pipeline system may have different legislations, failure modes and failure consequences compared to the submarine part. The scope covered herein is illustrated in Fig. 1-1. Landfall is considered a part of the scope unless otherwise specified.

The exact limit of the submarine pipeline system at the onshore end may differ from the definition herein based on different statutory regulations which may govern.

Onshore codes may also take precedence of this part due to legislation aspects, refer DNV-QS-F101, Appendix F “Requirements for shore approach and onshore sections”.

1.4 Structure of this Recommended Practice

This recommended practice is structured in the following manner:

— Sec.1 covers objective, scope, relation to other codes, references, definitions etc.
— Sec.2 outlines the main elements of an integrity management system including the core Integrity Management Process and support elements.
— Sec.3 covers the Integrity Management Process in a life cycle perspective.
— Sec.4 to 7 cover the core Integrity Management Process in more detail.
— The appendices include:

— pipeline statistics
— recommendations with regard to global buckling
— recommendations with regard to corrosion
— leak detection systems
— inspection and monitoring techniques
— example of risk assessment scheme
— example of risk assessment and IM planning.
— a working process for performing risk assessment

1.5 Relation to other codes

This recommended practice formally support and comply with the DNV-OS-F101. However, the recommendations are reflecting the overall industry practice for how to manage system integrity for submarine pipelines and hence the recommendations are also considered relevant for pipelines designed after other codes such as ISO 13623, API RP 1110 and API RP 1111.

The recommended practice aims to be a supplement to relevant national rules and regulations.

For the onshore sections, references are given to recommended practices as:

— ASME B31.8S “Managing System Integrity of Gas Pipelines”
— API 1160 “Managing System Integrity for Hazardous Liquid Pipelines”.

in addition to:

— DNV-OS-F101, Appendix F “Requirements for shore approach and onshore sections”.

For riser systems, the integrity management process is covered by:

— DNV-RP-F206 “Riser Integrity Management”.

1.6 Codes

1.6.1 DNV Offshore Standards

DNV-OS-F101 Submarine Pipeline Systems

1.6.2 DNV Recommended Practices

DNV-RP-C203 Fatigue Design of offshore steel structures
DNV-RP-F101 Corroded Pipelines
DNV-RP-F102 Coating repair
DNV-RP-F103 Cathodic protection
DNV-RP-F105 Free spanning Pipelines
DNV-RP-F107 Risk assessment of Pipeline Protection
DNV-RP-F109 On-bottom stability
DNV-RP-F110 Global buckling of Submarine Pipelines
DNV-RP-F113 Pipeline Subsea Repair
DNV-RP-F206 Riser Integrity Management
DNV-RP-H101 Risk Management in Marine - and Subsea Operations

1.6.3 Other References

API 1110 Pressure testing Liquid Pipelines
API 1160 Managing System Integrity for Hazardous Liquid Pipelines
API RP 1111 Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines (Limit State Design)
API 1163 In-Line Inspection System Qualification Standard
ASME B31.4 Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

ASME B31.8 Gas Transmission and Distribution Piping Systems
ASME B31.8S Managing System Integrity of Gas Pipelines
ASME B31.G Method for determining the remaining strength of corroded pipelines
ASNT IIL-PQ In-Line Inspection Personnel Qualification & Certification
BS-7910 Guide on methods for assessing the acceptability of flaws in metallic structures
EN 13509 Cathodic protection measurement techniques
ISO 13623 Petroleum and Natural Gas Industries – Pipeline Transportation Systems’
ISO 16708 Petroleum and natural gas industries – Pipeline transportation systems – Reliability-based limit state methods
ISO-17776 Petroleum and natural gas industries - Offshore production installations - Guidelines on tools and techniques for hazard identification and risk assessment
NACE RP 0102 Standard Recommended Practice, In-Line Inspection of Pipelines
NACE TR 35100 In-Line Non-Destructive Inspection of Pipelines
NORSOK Z-001 Documentation for Operation (DFO)

1.7 Bibliographies


1.8 Definitions

Acceptance Criteria (i.e. design limits): Specified indicators or measures providing an acceptable safety level and that are used in assessing the ability of a component, structure, or system to perform its intended function. The acceptance criteria should be quantifiable.

Commissioning: Activities associated with the initial filling of the pipeline system with the fluid to be transported, and is part of the operational phase.

Commissioning, De-: Activities associated with taking the pipeline temporarily out of service.

Commissioning, Re-: Activities associated with returning a decommissioned pipeline to service.

Crack: A planar, two-dimensional feature with displacement of the fracture surfaces.

Design life: The design life is the period for which the integrity of the system is documented in the original design. It is the period for which a structure is to be used for its intended purpose with anticipated maintenance, but without requiring substantial repair.

Failure: An event affecting a component or system and causing one or both of the following effects:
— loss of component or system function; or
— deterioration of functional capacity to such an extent that the safety of the installation, personnel or environment is significantly reduced.
**In-service**: The period when the pipeline system is under operation.

**Integrity control**: Activities to verify the integrity of a pipeline with respect to pressure containment. Covers both internal and external activities.

**Operation**: The day to day operation as defined in 3.5.4.

**Operator**: The party ultimately responsible for operation, and the integrity, of the pipeline system.

**Pig**: Device that is driven through a pipeline for performing various internal activities (depending on pig type) such as to separate fluids, clean or inspect the pipeline.

**Pig, Intelligent**: Pig that can perform non-destructive examinations

**Re-qualification**: Re-assessment of design due to modified design premises and/or sustained damage. E.g. life extension is a design premise modification.

**Risk**: The qualitative or quantitative likelihood of an accidental or unplanned event occurring considered in conjunction with the potential consequence of such a failure. In quantitative terms, risk is the quantified probability of a defined failure mode times its quantified consequence.

**Risk Management**: The entire process covering identification of risks, analysing and assessing risks, developing plans to control risks, and implementation and monitoring to evaluate effectiveness of the controls in place.

**Service Life**: The time length the system is intended to operate. The service life is a part of the application toward authorities.

**Supplier**: An organization that delivers materials, components, goods, or services to another organization.

**Take-over**: Is defined as the process of transferring operating responsibility from the project phase (up to an including pre-commissioning) to Operations.

**Threat**: An indication of an impending danger or harm to the system, which may have an adverse influence on the integrity of the system.

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### 1.9 Abbreviations

- **CoF** | Consequence of Failure
- **CP** | Cathodic Protection
- **CVI** | Close Visual Inspection
- **DEH** | Direct Electrical Heating
- **DFI** | Design Fabrication Installation
- **DFO** | Documents for Operation
- **DTM** | Digital Terrain Models
- **DVS** | Detailed Visual Inspection
- **ER** | Electrical Resistance
- **FMEA** | Failure Modes and Effects Analysis
- **FSM** | Field signature Method
- **GVI** | General Visual Inspection
- **GRP** | Glass Reinforced Plastic
- **HAZOP** | Hazard and Operability Analysis
- **HDPE** | High Density Polyethylene
- **HSE** | Health Safety and the Environment
- **IA** | Integrity Assessment
- **ILI** | In-Line Inspection
- **IM** | Integrity Management
- **IMP** | Integrity Management Process
- **IMS** | Integrity Management System
- **KP** | Kilometre Point
- **LPR** | Linear Polarisation Resistance
- **MIR** | Maintenance Inspection and Repair
- **MFL** | Magnetic Flux Leakage
- **NCR** | Non Conformances Report
- **NDT** | Non Destructive Testing
- **OLF** | The Norwegian Oil Industry Association (No:’ Oljeindustriens Landsforening.’)
- **PIMS** | Pipeline Integrity Management System
- **PoF** | Probability of Failure
- **RBI** | Risk Based Inspection
- **ROV** | Remote Operated Vehicle
- **ROTV** | Remote Operated Towed Vehicle
- **RP** | Recommended Practice
- **TPD** | Third Party Damage
- **UT** | Ultrasonic Testing
- **UTM** | Universal Transverse Mercator
- **VIV** | Vortex Induced Vibrations
- **QRA** | Quantitative Risk Analysis
2. Integrity Management System

2.1 General
The operator shall establish, implement and maintain an Integrity Management System (IMS) as required in DNV-OS-F101.

2.2 Elements of the Integrity Management System
The IMS shall, as a minimum, include the following elements, as illustrated in Fig. 2.1:

- company policy
- organisation and personnel
- reporting and communication
- operation controls and procedures
- management of change
- contingency plans
- audits and review
- information management
- the integrity management process.

2.2.1 Company policy
The company policy for pipeline integrity management should set the values and beliefs that the company holds, and guide people in how these are to be realized.

2.2.2 Organisation and personnel
The roles and responsibilities of personnel involved with integrity management of the pipeline system shall be clearly defined.

Training needs shall be identified and training shall be provided for relevant personnel in relation to management of pipeline integrity.

Guidance note:
Roles and responsibilities, related to safeguarding the integrity of the pipeline system, which should be addressed are typically:

- hand-over pipeline system for operations
- establish pipeline integrity management system
- execute technical integrity safeguarding activities
- execute and document integrity assessments
- ensure integrity management system improvement.

---e-n-d---of---G-u-i-d-a-n-c-e---n-o-t-e---

---e-n-d---of---G-u-i-d-a-n-c-e---n-o-t-e---

Figure 2-1
Integrity Management System

2.2.3 Management of change
Modifications of the pipeline system shall be subject to a management of change procedure that must address the continuing safe operation of the pipeline system.

Documentation of changes and communication to those who need to be informed is essential.

If the operating conditions are changed relative to the design premises, a re-qualification of the pipeline system according to Sec.4.6 should be carried out.

2.2.4 Operational controls and procedures
Relevant operational controls and procedures should be made available and should typically cover:

- start-up, operations and shutdown procedures
- procedures for treatment of non-conformances
- instructions for cleaning and/or other maintenance activities
- corrosion control activities
- monitoring activities; and
- procedures for operation of safety equipment and pressure control systems.
Operation control measures shall be in place to ensure that critical fluid parameters are kept within the specified design limits. As a minimum, the following parameters should be controlled or monitored:

- pressure and temperature at inlet and outlet of the pipeline
- dew point for gas lines
- fluid composition, water content, flow rate, density and viscosity.

All safety equipment in the pipeline system, including pressure control and over-pressure protection devices, emergency shut-down systems and automatic shutdown valves, shall be periodically tested and inspected. The purpose of the inspection is to verify that the integrity of the safety equipment is intact and that the equipment can perform the safety function as specified.

2.2.5 Contingency plans

Plans and procedures for emergency situations shall be established and maintained based on a systematic evaluation of possible scenarios. Dependant upon the commercial criticality of the pipeline system, plans and procedures for contingency repair of the pipeline should also be established.

Guidance note:

Contingency (emergency) preparedness procedures - A pipeline emergency is defined as being any situation or occurrence that endangers the safety of persons, plant, the environment or safe operation of the pipeline. Possible consequences of pipeline failures (e.g. rupture) shall therefore be established. To reduce the consequences of a potential emergency scenario, preparedness plans and procedures shall be developed and implemented for pipeline systems. The submarine pipeline system emergency procedures shall include the following:

- organisation, roles and responsibilities of parties involved in the event of an emergency situation
- communication lines, who to be informed through different stages of the emergency situation
- identification of potential pipeline specific emergency scenarios
- sources and systems for identifying and reporting an emergency situation
- procedures for initial response to an emergency alarm and/or situation, e.g.: Isolation of damaged part of the pipeline system; Controlled shut-down procedures, and Emergency shut-down procedures; Procedures for depressurisation of the system
- plans, organisation, support- and resource teams responsible for evaluating and initiating the appropriate actions to an emergency situation
- mitigating plans / procedures to limit potential environmental damage from an emergency scenario.

Contingency repair procedures - When evaluating the extent of required contingency plans and procedures, and the corresponding need for pre investments in contingency repair equipment and/or spares, the following should be considered:

- economical consequences when the pipeline is out of service
- availability of recognised repair methods
- availability/delivery time for required equipment and spares
- estimated time for repair.

---end---of---Guidance---note---

2.2.6 Reporting and communication

A plan for reporting and communication to employees, management, authorities, customers, public and others shall be established and maintained.

This covers both regular reporting and communication, and reporting in connection with changes, special findings, emergencies etc.

2.2.7 Audit and review

Audits and reviews of the pipeline integrity management system shall be conducted regularly. The frequency shall be defined by the responsible for the operation of the pipeline system. The focus in reviews should be on:

- effectiveness and suitability of the system
- improvements to be implemented.

The focus in audits should be:

- compliance with regulatory and company requirements,
- rectifications to be implemented.

2.2.8 Information management

A system for collection of historical data shall be established and maintained for the whole service life. This system will typically consist of documents, data files and databases.

2.2.9 Integrity Management Process

The Integrity Management Process (IMP) is the core of the Integrity Management System (IMS) and consists of the steps:

- Risk Assessment and Integrity Management (IM) Planning which includes threat identification, risk assessments, long term and short term (annual) inspection planning.
- Prior to being put in service, an Integrity Management Philosophy should be developed taking into consideration the design of the pipeline and how the integrity of the system should be managed and reported.
- Detailed planning and performance of Inspection (external and internal), Monitoring and Testing activities.
- Integrity Assessment based on inspection and monitoring results and other relevant historical information.
- Performance of needed Mitigation, Intervention and Repairs activities.

The steps constituting the IM process are illustrated in Fig. 3.1 and further discussed in Sec.3.

As stated in 1.3, the main focus of this recommended practice is the Integrity Management Process.

2.3 Pipeline system integrity

Pipeline system integrity is defined as the pipeline system's structural/containment function. This is the submarine pipeline system's ability to operate safely and withstand the loads imposed during the pipeline lifecycle. If a system loses this ability, a failure has occurred.

The function of submarine pipeline systems is to efficiently and safely transport fluids. This is related to flow assurance and structural containment function.

A failure is the termination of the ability of an item to perform according to its required function. It is an event affecting a component or system and causing one or both of the following effects, DNV-OS-F101:

- loss of component or system function; or
- deterioration of functional capability to such an extent that the safety of the installation, personnel or environment is significantly reduced.

There are two main failure modes related to the pipeline's containment/structural function:

1) Loss of containment - leakage or full bore rupture.
2) Gross deformation of the pipe cross section resulting in either reduced static strength or fatigue strength.

Pipeline integrity is established during the concept, design and construction (fabrication and installation) phases.
Pipeline integrity is maintained in the operations phase. Integrity is said to be transferred from the design phase to the operations phase. This interface involves transfer of vital data and information about the system.

This is covered in more detail in 3.5.3.

### 2.4 Pipeline system threats

Submarine pipeline system threats are the root causes that may lead to a failure.

Managing the risk related to these threats is essential for maintaining the integrity of the pipeline system. An overview of the most common submarine pipeline threats is presented in Table 3-1.

The advantages of grouping the threats as shown in Table 3-1 are that:

- it should be possible to evaluate all threats within a group as “one threat”
- observed failures at threat group level can be compared to failure statistics (or be used as failure statistic at company level)
- it may be possible to plan and execute an inspection (by use of one inspection type) and cover all the threats within the group.

The combined effect of threats should also be considered.

### 2.5 Risk based approach

General industry practice is that a risk based integrity management approach should be applied.

The intention of using a risk based approach is that the activities (inspection, monitoring and testing) are selected and scheduled on the basis of their ability to explicitly measure and manage threats to the pipeline system and ensure that associated risks are managed to be within acceptable limits.

Risk based pipeline integrity management takes into account:

- identification of threats and failure modes
- estimation of probabilities of failure (PoF)
- estimation of consequences of failure (CoF)
- estimation of risk level (CoF × PoF).

Submarine pipeline system failures can have severe safety, environmental and economic consequences at corporate and national level. Submarine pipeline systems may comprise many sub-systems each with several threats that may lead to failure. Risk assessments are used to focus on the right issues at the right time. It is used to prioritize and schedule activities. This is further described in Sec.4.

### 2.6 Safety philosophy

As a basic principle, the safety philosophy adopted in design shall apply. However, the original safety philosophy may be modified as a result of company/operator, industry and society developments, improvements and better knowledge of the pipeline system.

**Guidance note:**

As an example, the freespan acceptance criterion may be modified based on a better understanding, improved knowledge of the pipeline system and more accurate calculations resulting in a revised acceptance criterion for safe operation.

Safe operation means operating the pipeline in accordance with a set of acceptance criteria as established in design and as revised through the project phases and service life.

Revision of the acceptance criteria can take place as:

- a result of improved knowledge with regards to known threats to the system
- identification of new threats
- a requalification is performed.

Acceptance criteria as defined in design shall therefore be identified prior to start of operation and adhered to during operation and revised during the service life if necessary.

A change in the basis for design will require a re-qualification as described in 3.6.

It must be verified that design and operating premises and requirements are fulfilled. If this is not the case, appropriate actions shall be taken to bring the pipeline system back to a safe condition.

### 2.7 Authority and company requirements

The relevant national requirements shall be identified and complied with.

The relevant company requirements should be complied with when developing, implementing and following up the integrity management system.

### 2.8 Operator's responsibility

Ensuring the integrity of the pipeline system is the ultimate responsibility of the Operator.

Within the Operator's organisation, the responsibilities must be clearly defined and allocated during the entire service life of the pipeline system.
3. Integrity Management Process

3.1 General

Pipeline systems shall be designed and operated safely, with respect to human, environment and economy, to maximise the life cycle value. The process is a continuous process applied throughout design, construction, installation, operation and decommissioning phase to ensure that the system is operated safely.

The Integrity Management Process as described in 2.2.9, consists of the four main groups as illustrated in Fig. 3-1.

All activities in the management of pipeline systems should be planned.

This section presents an overview of IM-process with focus on IM-planning (Sec.3.4) and the IM-process in a lifecycle perspective (Sec.3.5). Each of the four main groups of activities is covered in more detail in Sec.4 to 7.

Figure 3-1
Integrity Management Process constitutes the 'core' of Fig. 2-1

3.2 Overview of the Integrity Management Process

The Integrity Management Process as a whole is a long term and iterative process that involves planning, execution, evaluation and documentation of:

— integrity control activities which cover inspection, monitoring, testing and integrity assessments, and
— integrity improvement activities which cover mitigation, intervention and repair activities

for the purpose of continuously maintaining the pipeline system's integrity.

The 'Risk assessment & IM planning' is a key activity and delivers long term and fundamental strategies on a superior level and shall be normative for the integrity control and integrity improvement activities. In addition, it delivers both initial inspection plans and annual plans as described in 3.4.

The Integrity Control and Integrity Improvement activities include preparation of detailed plans (i.e. work descriptions) before they are executed, evaluated and reported/documented. The detailed plans are governed by the strategies and may also be risk based. Evaluations include both an evaluation against any established acceptance criteria, and an evaluation of the whole process for the purpose of continuous improvements.

The central activity of 'Risk Assessment and IM Planning' must also be planned for in detail before being executed, evaluated and reported/documented.

The entire process shall begin during the early design phase and shall be carried out continuously and iteratively throughout the operation and maintenance campaigns (e.g. cleaning pigging) of the pipeline system as described in Table 3-2 and 3.5.1.

The strategies and plans are normally risk based.

3.3 From threats to failures in the Integrity Management Process

A threat may result in a damage/anomaly. Metal loss due to corrosion is an example of a damage that may be initiated by e.g. the presence of water. Corrosion is a degradation mechanism that will develop with time. Other damages may be initiated by accidental incidents as e.g. coating damage due to a trawl board hit. A buckle is an example of an anomaly that may be initiated by functional loads (pressure, temperature, flow rate). A damage/anomaly can develop into a failure. This is illustrated in Fig. 3-2.

Figure 3-2
The development of a threat into a failure and the activities implemented to reduce the likelihood and/or consequence of such development

Table 3-1 lists typical damages/anomalies related to different threats. Note that a primary damage can develop into a secondary damage. E.g. a third party damage may cause a degradation of the coating which may lead to external corrosion (i.e. metal loss).

In order to reduce the risk of threats, different protective means are normally introduced in the DFI-phase. This can be e.g. chemical injection systems preventing internal corrosion or rock dumps preventing the risk of buckling or third party damage. Inspection, monitoring and testing activities are carried out in other to reveal damages/anomalies at an early stage and the development of these. Prediction models are important tools for assessing the development of damages (ref. Sec.6). Examples of prediction models are:

— corrosion rate
— erosion rate
— crack growth
— estimation of probability of incidents.

In order to avoid failures by reducing the possibility of development of a damage/anomaly into a failure (as burst, leakage and collapse), different types of mitigation, intervention and repair activities should performed (ref. Sec.7).
### Table 3-1 Typical damages/anomalies related to the different threats

<table>
<thead>
<tr>
<th>Threat group</th>
<th>Threat</th>
<th>Damage / anomaly</th>
</tr>
</thead>
<tbody>
<tr>
<td>DFI threats</td>
<td>Design errors</td>
<td>- Metal loss</td>
</tr>
<tr>
<td></td>
<td>Fabrication related</td>
<td>- Dent</td>
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<tr>
<td></td>
<td>Installation related</td>
<td>- Crack</td>
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<td></td>
<td></td>
<td>- Gouge</td>
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<td></td>
<td></td>
<td>- Free span</td>
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<td></td>
<td></td>
<td>- Local buckle3-Glo-</td>
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<tr>
<td></td>
<td></td>
<td>bal buckle</td>
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<td></td>
<td></td>
<td>- Displacement</td>
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<tr>
<td></td>
<td></td>
<td>- Exposure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Coating damage</td>
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<tr>
<td></td>
<td></td>
<td>- Anode damage</td>
</tr>
<tr>
<td>Corrosion/erosion</td>
<td>Internal corrosion</td>
<td>- Metal loss</td>
</tr>
<tr>
<td>threats</td>
<td>External corrosion</td>
<td>- Crack</td>
</tr>
<tr>
<td></td>
<td>Erosion</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>Third party threats</td>
<td>Trawling interference</td>
<td>- Metal loss (secondary)</td>
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<tr>
<td></td>
<td>Anorching</td>
<td>- Dent</td>
</tr>
<tr>
<td></td>
<td>Vessel impact</td>
<td>- Crack</td>
</tr>
<tr>
<td></td>
<td>Dropped objects</td>
<td>- Gouge</td>
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<tr>
<td></td>
<td>Vandalism / terrorism</td>
<td>- Local buckle</td>
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<tr>
<td></td>
<td>Traffic (Vehicle</td>
<td>- Global buckle</td>
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<tr>
<td></td>
<td>impact, vibrations)</td>
<td>Displacement</td>
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<tr>
<td></td>
<td>Other mechanical</td>
<td>- Coating damage</td>
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<tr>
<td></td>
<td>impact</td>
<td>- Anode damage</td>
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<td></td>
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<td></td>
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<tr>
<td>Structural threats</td>
<td>Global buckling –</td>
<td>- Crack</td>
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<tr>
<td></td>
<td>exposed</td>
<td>- Free span</td>
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<tr>
<td></td>
<td>Global buckling –</td>
<td>- Local buckle</td>
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<tr>
<td></td>
<td>buried</td>
<td>- Global buckle</td>
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<td></td>
<td>End expansion</td>
<td>- Displacement</td>
</tr>
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<td></td>
<td>On-bottom stability</td>
<td>- Exposure</td>
</tr>
<tr>
<td></td>
<td>Static overload</td>
<td>- Coating damage</td>
</tr>
<tr>
<td></td>
<td>Fatigue (VIV, waves</td>
<td>- Anode damage</td>
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<tr>
<td></td>
<td>or process variations)</td>
<td></td>
</tr>
<tr>
<td>Natural hazard threats</td>
<td>Extreme weather</td>
<td>- Dent</td>
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<tr>
<td></td>
<td>Earthquakes</td>
<td>- Crack</td>
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<tr>
<td></td>
<td>Landslides</td>
<td>- Gouge</td>
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<td></td>
<td>Ice loads</td>
<td>- Local buckle</td>
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<td></td>
<td>Significant temperatu-</td>
<td>- Global buckle</td>
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<td></td>
<td>re variations</td>
<td>Displacement</td>
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<tr>
<td></td>
<td>Floods</td>
<td>- Exposure</td>
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<td></td>
<td>Lightning</td>
<td>- Coating damage</td>
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<tr>
<td></td>
<td></td>
<td>- Anode damage</td>
</tr>
<tr>
<td>Incorrect operation</td>
<td>Incorrect procedures</td>
<td>- Metal loss</td>
</tr>
<tr>
<td>threats</td>
<td>Procedures not</td>
<td>- Coating damage</td>
</tr>
<tr>
<td></td>
<td>implemented</td>
<td>- Global buckle</td>
</tr>
<tr>
<td></td>
<td>Human errors</td>
<td>- Local buckle</td>
</tr>
<tr>
<td></td>
<td>Internal Protection</td>
<td>- Anode damage</td>
</tr>
<tr>
<td></td>
<td>System Related</td>
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<tr>
<td></td>
<td>Interface component</td>
<td></td>
</tr>
<tr>
<td>related</td>
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</tbody>
</table>

*) Threats related to the onshore section of the submarine pipeline system are given in ASME B31.8S and API 1160.

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### 3.4 Risk Assessment and Integrity Management Planning

The inspection plans give minimum required inspections (incl. max. intervals) for different pipeline sections, based on the given design and mitigation actions taken. It assumes that no unforeseen events are reported during operation or revealed during inspection campaigns. More frequent intervals may be performed if inspection of the entire pipeline is found more practical and/or economical.

The pipeline inspection plans are normally based on the following assumptions:

- no outstanding non-conformances from pipeline design, fabrication and installation
- a successful as-laid survey, with respect to damages to external coating and CP-system, performed prior to backfilling of all buried line sections. (ref. DNV-OS-F101 Sec.10 J)
- pipeline external as-built survey prior to start up i.e. cold condition (ref. DNV-OS-F101 Sec.10 N).

The above assumptions shall be confirmed prior to the development of the inspection plan. The inspection points that will be included in the inspection plan shall be determined based on the following:

- a criticality assessment; components that have a higher degree of uncertainty (or risk) should be placed on a periodic inspection plan
- issues with certain systems or components that arise either during fabrication or installation may require more frequent inspection or closer follow-up
- some subsea installations have various sensors and monitoring devices (e.g. sand control, dew-point control, corrosion coupons) installed to monitor the performance or integrity of the system. The information gathered from such systems should be incorporated into the inspection plan.

For each inspection point or system sensor, the visual indication or parameter that should be monitored needs to be identified and a criterion for taking further corrective action or inspection needs to be defined.

Planning and scheduling should also involve the necessary logistical activities such as e.g. sourcing and allocation of spares, availability of inspection/survey equipment, manning and relevant procedures.

The iterative process for risk assessment and inspection planning initiated in the design phase and updated throughout the entire service life is illustrated in Fig. 3-3 and the individual steps are described below.

**Guidance note:**

Inspection planning covers, in this recommended practice, both inspections, monitoring, testing and possible maintenance activities as e.g. cleaning pigging.

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**Initial Risk Assessment:**

An initial risk assessment should be performed in the design phase and verified or updated as part of the transfer from design to operation. The threats (hazards) to the system shall be identified and the preventing or mitigating measures implemented in the DFI-phase shall be listed.

The output from the risk assessment (i.e. the integrity safeguarding activities) should be documented in a ‘Risk assessment scheme’ which should include:

- mapping of threats to the system
- protective means and integrity control activities
- acceptance criteria (i.e. design criteria)
- associated risks.

An example of a ‘Risk assessment scheme’ is given in Appendix F.

**Guidance note:**

In order to document the applicability of the various threats, it is recommended that the Initial Risk Assessment includes a qualitative analysis of all potential failure mechanisms for a pipeline, including possible ‘sub mechanisms’. A full risk assessment to be carried out for threats relevant to the actual pipeline.
Initial inspection plan:
The initial inspection program, relevant for new or modified pipeline systems, gives minimum required inspections (incl. max. intervals) for different pipeline sections. The objective of the initial inspection plan is to verify that the behaviour of the pipeline is in accordance with expected development as predicted during the design phase. The initial program shall be based on design documentation, DFI resumes, HAZOP studies, discussions, previous experience and best practices in addition to sound engineering judgement.

The risk assessment scheme will be the basis for the initial program. The program shall be developed, and available, prior to the pipeline system is put in operation.

Risk Assessment:
An update of the Initial Risk Assessment should be performed by the Operator when the pipeline is taken over for operation. This to ensure that no new threats have been introduced to the pipeline during the pre-commissioning or commissioning phase.

Long term inspection plan:
When the pipeline system is taken over by the Operator, the initial inspection plans will constitute the basis for the long term inspection plans.

Annual update of inspection plan:
Inspection and condition monitoring of the pipeline system shall be carried out regularly according to the prepared inspection plans.

If certain elements / inspection points show excessive degradation a more rigorous inspection regime should be applied in addition to investigating the cause of degradation. Equivalent, if no degradations are recorded over time, the possibility of extending the inspection intervals from the initial plan should be considered.

The plans shall be annually updated based on information gained in the same period and on knowledge about the application of new analysis techniques / methods within condition monitoring and inspection.

The confidence in the inspection results and monitoring data shall be taken into consideration.

Periodic update of Risk Assessment & IM plans:
The risk for a threat to occur might change with time, for example in the form of change in trawling activities (offshore), in population (onshore), in the design of trawling and fishing equipment, new methods for inspection and monitoring etc. A detailed re-assessment of the entire inspection program including risk analyses should therefore be performed each 5-7 year.

Event Based Inspections:
If a certain event occurs such as a dropped object or a monitoring parameter that is exceeded its acceptance criteria, this should trigger a separate investigation or more frequent inspections. The periodic inspection plan shall be updated accordingly.

The development of IM plans and the risk assessment methodology which constitute the basis for the risk based inspection (RBI) plans are further described in Sec.4.
Further, if design and construction are acceptable but the in-service integrity management is inadequate, the integrity might be diminished over time.

In the context of this recommended practice, it is important to emphasize that a properly designed and constructed pipeline system is a system that carries out its intended function, and can be maintained in a cost efficient manner.

Integrity is transferred from the Establish Integrity stage to the Maintain Integrity stage. This interface involves transfer of relevant data (e.g. DFO) required for safe operation of the pipeline system.

3.5.2 Establish Integrity

During the Establish Integrity stage, the Operator should allocate resources and qualified representatives during the concept, design and construction phase. The purpose is to ensure that operational aspects are taken into consideration, and planned for, at an early stage. Table 3-3 gives an overview of the Establish Integrity Stage and recommendations with regards to the integrity management (IM) process.

Design Fabrication Installation (DFI) résumé

A Design Fabrication Installation (DFI) résumé, or similar, shall be established with the main objective to provide the operations organisation with a concise summary of the most relevant data (i.e. acceptance criteria, events etc) from the design, fabrication and installation (incl. pre-commissioning) phase. The DFI résumé shall clearly show the limits of the pipeline system.

The DFI résumé should:

— reflect the as-built status of the pipeline system and provide information for the preparation of plans for inspection and maintenance
— specify design and operating premises and requirements
— contain all documentation required for normal operation, inspections and maintenance
— provide references to the documentation needed for any repair, modification or re-qualification of the pipeline system
— aim at being prepared in parallel, and as an integrated part, of the design, fabrication and installation phase of the project.

Minimum requirements to the content of a DFI résumé are given in DNV-OS-F101, Sec.12 H200

3.5.3 Transfer integrity - From design to operations

As the concept, design and construction phases reach their end, the development and establishment of the integrity management system should be well on the way.

The level of effort needed to ensure a successful transfer of integrity depends on the risks to the pipeline system, the complexity of the system and the experience of the Operator's organization.

This section provides general recommendations to this important interface phase to ensure integrity during the entire service-life.

Key Processes and timing

The main processes are:

— transfer of documents and databases relevant for the operational phase
— identification and cooperation with the project organization to resolve any engineering and/or technical information issues which are critical for take-over.
— training of operations staff.

See Appendix B for an example of information that may be useful to transfer from the project to operations with regard to global buckling. Similar generic lists can be established for all the pipeline threats.

Whilst the integrity transfer activities reach their peak during pre-commissioning and commissioning, some activities need to start earlier. These include identification, specification, and verification of documents for operation (DFO), and identifying training needs.

Planning

Transfer of integrity from design to operations shall be planned and, as a minimum, the following plans should be established:

— philosophy and strategy for transfer of integrity early in the concept development phase
— detailed plans for hand-over and
— plans for DFO.

The plan is established to ensure that information about operational aspects related to personnel, procedures and technical systems are ready for hand-over and start-up of operation, and that acceptable integrity performance can be achieved throughout the operational life.

Organization

The organization structure will vary with time across the different development phases with different focus and requirements for different skills/competencies.

Direct involvement of staff from the operations group into the development project offers:

— an opportunity to maximize value over the asset life by ensuring relevant operations input to design and construction of the pipeline system, and
— an intimate knowledge of the system which will facilitate safe operations and integrity management which they will bring back to the operation group when they return from the development project phase.

Table 3-2 Integrity Management Process in a life cycle perspective

<table>
<thead>
<tr>
<th>Establish integrity</th>
<th>Maintain integrity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concept, design and construction</td>
<td>Operation (from commissioning until decommissioning)</td>
</tr>
</tbody>
</table>

INTEGRITY MANAGEMENT PROCESS

Risk Assessment and Integrity Management (IM) Planning

| Inspection, monitoring and testing |
| Integrity Assessment |
| Mitigation, intervention and repair |
Risk Focus

According to 2.5, a systematic review of risks shall be carried out at the concept phase and further developed and refined during the design and construction phases. This entails identifying the main threats to the system and their associated risks, and subsequently developing strategies to manage these risks. During the transfer of integrity from project to operations, each threat and associated risk shall be individually considered and the required information from design and construction identified. (Ref. Appendix B as an example).

| Table 3-3 Overview of the Establish Integrity and recommendations for the IM-Process |
|---|---|---|---|
| Phases | Business & Concept | Basic Design | Detail design | Construction |
| Typical activities | Feasibility | Material selection/Wall thickness design | Installation design (Routing and survey; Local buckling; combined loading; Tie-in) | Linepipe, components and assemblies |
| | Project basis & premises: (Safety philosophy; Accident loads; Flow assurance; System layout) | (Material selection; Corrosion; Material and links to design; Load effects; Pressure containment; Local buckling; CP design) | Design for operation (Installation analyses; High Pressure/High Temperature; On-bottom stability; Free span/fatigue; Trawl-ing; Protection) | Corrosion protection and weight coating |
| | Preliminary Material selection & Wall thickness design | Preliminary Installation design | | Welding; NDT |
| | Hydraulic calculations | Preliminary Design for operation | | Pre-intervention; Installation; Post- intervention; Pre-commissioning |
| Inappropriate strategic decisions at the front end (business phase) can lead to poor performance in the operation and maintenance phase. Integrity issues should already be considered. This is particularly important if the considered development represents potential new technology risks because it is pushing the boundaries beyond what has been developed before. The concept development includes further qualification of any new technology, selection of engineering standards, addressing the HSE risks during operations, and establishing prequalification requirements, with integrity criteria, to ensure competence of contractors and vendors. Preliminary development of strategies for inspection, monitoring, testing and repair shall begin during the concept development phase (ref. DNV-OS-F101 Sec.3 B). It is recommended that representatives of operations / integrity management participate in these preliminary strategy developments. |
| Recommendations for involvement of the Operator | In these phases, the major decisions have been made, and the integrity management activities focus on the quality assurance of the pipeline system. Steps should be taken to identify key risks (and these should be agreed with both design and operations), and establish integrity controls, and define key assurance activities. |
| | Detailed performance standards for critical components and systems should be specified as the basis for assuring compliance with the design intent and the integrity goals. |
| | The deviation control procedure should provide for operations review of deviations. Strategies for inspection, monitoring, testing and repair should be further developed by representatives of operations / integrity management in close co-operation with the design team. |
| | Representatives of operations / integrity management should be involved in the development of the Design resume, especially with regard to recommendations for operations, premises for operation, acceptance criteria and design. |
| | During and after construction, strategies for inspection, monitoring, testing and repair should be finalised by representatives of operations / integrity management. |
| | Representatives of operations / integrity management should be involved in the development of the Fabrication and Installation resume, especially with regard to recommendations for operations. |
| | A DFI résumé shall be established. |

Documents for Operation (DFO)

DFO requirements shall be established defining formal requirements (language, formats, file name conventions, etc.) and requirements for document content. DNV-OS-F101, Sec.12 presents minimum documentation requirements for the whole life cycle of a submarine pipeline system including requirements for documentation to be established for the operation of the system.

Guidance note:
The NORSOK standard “Documentation for Operation Z-001” also provides requirements both on a general basis and specifically for pipeline systems.

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Take-over

A plan for take-over of the pipeline system and a checklist for project deliverables that are considered essential for take-over should be prepared.

Guidance note:
'Take-over' is defined as the process of transferring operating responsibility from the project phase (up to including pre-commissioning) to Operations.

There are three main categories of information that should be verified before take-over:

- engineering, i.e. verifying that project activities are completed and that the operations organization has included all necessary engineering information in operating procedures and plans. E.g. corrosion management strategy completed and included in the initial inspection program.
- documents for Operation (DFO) i.e. verify that all user documents required for operation are complete, according to specification and available to the operations organization e.g. user manuals, temporary pig launcher installation procedure, field layout & pipeline route etc.
- take-over Dossier i.e. installation and pre-commissioning is complete and documented by the project e.g. relevant certificates, list of NCRs, DFI resume, initial inspection plans, pipeline crossing agreements etc.

Check lists should be prepared, including responsible persons, to verify and document that the above requested information is received prior to take-over.

3.5.4 Maintain Integrity

Maintain integrity covers the operation of the pipeline system from commissioning and up to and including abandonment.

A brief description of the different phases and issues considered as important for the IM-process, and which may influence the integrity of the system, are listed below.

Commissioning

Commissioning comprises activities associated with the initial filling of the pipeline system with the fluid to be transported, and is part of the operational phase. Requirements pertaining to documentation and procedures for commissioning are specified in DNV-OS-F101.

Following commissioning of the system, it shall be verified that the operational limits are within design conditions. Other important issues that may need verification can be: flow parameters (pressure, temperature, dew point conditions, hydrate formation sensitivity, sand production, etc.), CP-system, expansion, movement, lateral snaking, free span and exposure.

An in-service strategy for inspection, monitoring and testing is normally established prior to commissioning as a part of the Risk Assessment and IM Planning activity - see Sec.4. Any detailed plans should also be ready prior to commissioning. Events that occur during commissioning may lead to additional inspection and/or revised inspection plans.

Operation

The day to day operation including:

- operational control procedures and activities
- start-up and shutdown procedures
- cleaning and maintenance, etc.
- inspection, monitoring and testing
- mitigation, intervention and repair
- storage and preservation of spares and contingency equipment.

De-Commissioning

De-commissioning is the set of activities associated with taking the pipeline temporarily out of service. Pipeline de-commissioning shall be planned and prepared. It includes aspects such as relevant national regulations, environment, obstruction for ship traffic and fishing activities, and corrosion impact on other structures, ref. DNV-OS-F101.

De-commissioning shall be conducted and documented in such a way that the pipeline can be re-commissioned and put into service again.

De-commissioned pipelines shall be preserved to reduce effect from degradation mechanisms, ref. DNV-OS-F101.

De-commissioned pipelines shall continue being appropriately managed by the Integrity Management System, i.e. they will e.g. still be covered by inspection, monitoring and testing strategies as necessary.

Re-Commissioning

The purpose of re-commissioning is to restore the original intended operating performance.

As for commissioning from the construction phase into the operational phase, preservation measures should be appropriately terminated, correct fluid filling should be ensured and integrity should be verified. The main difference is that a de-commissioned system may be out of service for a very long period and the verification of integrity may be more challenging.

Further, after a system has been de-commissioned, non-operational control strategies, faulty equipment, and deferred maintenance may result in system inefficiencies that are not readily noticeable.

3.6 Re-qualification / Lifetime extension

3.6.1 General

Re-qualification is a re-assessment of the design under changed design conditions.

A re-qualification may be triggered by a change in the original design basis, by not fulfilling the design basis or by mistakes or shortcomings discovered during normal or abnormal operation. Possible causes may be:

- preference to use a more recent standard e.g. due to requirements for higher utilisation for existing pipelines
- changes of premises such as environmental loads, deformations, scour etc
- changes of operational parameters such as pressure, temperature, the composition of the medium, water content, H2S-content etc
- change of flow direction or change of fluid
- deterioration mechanisms having exceeded the original assumption such as corrosion rate (internal or external), dynamic responses causing fatigue (e.g. VIV or start/stop periods)
- extended design life (ref. 3.6.2)
- discovered damages such as dents, damaged pipe protection, corrosion defects, cracks, damaged or consumed anodes.

3.6.2 Lifetime Extension

World wide the Operators experience that their pipeline systems reach their original design life while there is still a need to operate the systems for more years.

As pipelines age, the operators have several new challenges to consider when required to operate beyond the design life such as:

- changes in integrity, e.g. time dependent degradation mechanisms such as corrosion and fatigue or random mechanical damages (e.g. third party damages)
— changes in infrastructure from the as built, e.g. increased fishing activity or heavier trawl gear
— changes in operational conditions, either as a natural change in well-stream condition, tie-in to other pipeline system or increased production rates.

This has called for guidelines on what should be assessed when required to operate beyond the design life and still ensure compliance with the original safety level.

Two initiatives, initiated by ISO and OLF, are run in parallel to come up with such guidelines, documented in two separate draft report:

— ISO/TC67/SC2/WG17: 'Pipeline Life Extension' /1/ and
— draft OLF- NORSOK Y-xx: 'Life Extension for Transportation Systems' /2/.

The documents are still under development.

ISO /1/

The proposed ISO guideline defines the scope that this guideline is applicable to and when its application should be triggered. It then gives guidance on what information should be gathered and evaluated in order to determine what measures are required to be put in place to allow the pipeline system design life to be extended. It also gives guidance to what should be included within a report that would give the technical credibility required to provide acceptance to extending the life of the pipeline system.

The following flow chart Fig. 3-4 details the lifetime extension process that is followed during the assessment of a pipeline. The numbered blocks within the flow chart cross reference the sections in the guideline which describe the process.

OLF/NORSOK /2/

The proposed NORSOK standard defines general principles for assessing an extension of the service life beyond the original service life of risers and pipeline transportation systems. This may require extension of the design life premised in the original design (for definitions of "design life" vs “service life”, see 1.8).

The transportation system is primarily identified by the parts of the transport systems that have the function of pressure containment.

The purpose of the life extension process is to document acceptable system integrity to the end of the extended service life and a general methodology to be applied to a life extension process is described in the guideline.

Fig. 3-5 outlines the life extension process. The overall life extension methodology is described as:

— define the premise for the extended operation, and identify new threats to the system
— assess the integrity of the system, in other words as far as possible quantify the current condition
— carry out a reassessment of the system based on the available information, current industry practice and available technology
— the reassessment can conclude that the integrity of the system is acceptable up to the end of the extended life, in which case the process moves on to documentation and implementation. If the integrity is not acceptable, modifications must be considered, and possibly the feasibility of the entire life extension.

3.7 Abandonment

Abandonment of a pipeline system comprises the activities associated with taking the system / or part of the system permanently out of operation. An abandoned pipeline can not be returned to operation. Depending on the legislation this may require physical cover or removal.

Pipeline abandonment shall be planned and prepared.

Pipeline abandonment evaluation shall include the following aspects:
— relevant national regulations
— health and safety of personnel, if the pipeline is to be removed
— environment, especially pollution
— obstruction for ship traffic
— obstruction for fishing activities, and
— corrosion impact on other structures.

Abandoned parts of a pipeline system may continue being managed by the Integrity Management System, i.e. they may e.g. still be covered by inspection strategies as necessary.

The main concern from the authorities is that environmental issues should be handled such that there will be no HSE issues related to abandoned pipelines. Third parties should not have restrictions due to the abandonment. For submarine pipelines this is mostly fisheries with trawlers.

**Guidance note:**

The OSPAR convention (The Convention for the Protection of the Marine Environment of the North-East Atlantic) does not give any restriction for dumping of cables and pipelines at sea. They state that this shall be in agreement with competent authorities in the individual country involved.

The Norwegian authority rules and regulations into this area are limited in details, however the Petroleum act states that owner or operator is responsible for damage or inconveniences abandoned installations may cause.

---end---of---Guidance---note---

### 3.8 Documentation

In order to maintain the integrity of the pipeline system, the documentation made available during the operational phase shall include, but not be limited to:

— organisation chart showing the functions responsible for the operation of the pipeline system
— personnel training and qualifications records
— history of pipeline system operation with reference to events which may have significance to design and safety
— installation condition data as necessary for understanding pipeline system design and configuration, e.g. previous survey reports, as-laid / as-built installation drawings and test reports
— physical and chemical characteristics of transported media including sand data
— inspection and maintenance schedules and their records
— inspection procedure and results, including supporting records.

In case of mechanical damage or other abnormalities that might impair the safety, reliability, strength and stability of the pipeline system, the following documentation shall, but not be limited to, be prepared prior to start-up of the pipeline:

— description of the damage to the pipeline, its systems or components with due reference to location, type, extent of damage and temporary measures, if any;
— plans and full particulars of repairs, modifications and replacements, including contingency measures; and
— further documentation with respect to particular repair, modification and replacement, as agreed upon in line with those for the construction or installation phase.

In case of re-qualification / lifetime extension of the pipeline system (ref. 3.6), all information related to the re-assessment process of the original design shall be documented.

**Information management**

A system for collection of historical data, an in-service file, shall be established and maintained for the whole service life. The in-service file will typically consist of documents, data files and data bases.

The in-service file, together with the DFI-resume, shall be the basis for future inspection planning.

The in-service file and the DFI-resume shall be easily retrievable in case of an emergency situation.

The in-service file shall as a minimum contain documentation regarding:

— results and conclusions from the in-service inspections
— accidental events and damages to the pipeline system
— intervention, repair, and modifications and
— operational data (fluid composition, flow rate, pressure, temperature etc.) including evaluation of incidents promoting corrosion and other deterioration mechanisms.
4. Risk Assessment and Integrity Management (IM) Planning

4.1 General

Threats which could directly or indirectly jeopardise the integrity of the pipeline system shall be evaluated using a risk based approach. The risk assessment shall cover the entire pipeline system. All components which failure could affect the structural integrity of the pipeline system shall be included. Risks shall be evaluated qualitatively or quantitatively as most feasible.

A report of the risk identification and assessments shall be prepared and properly documented. Risks that require any actions should be highlighted together with identified integrity control and improvement activities.

Inspection plans shall be established in the design phase and implemented in the organisation prior to production start-up (Initial inspection plan). This plan typically covers at least 8-years but shall be updated annually (ref. Sec.3.4 Annual update of inspection plan).

A detailed re-assessment of the entire inspection program should however be performed when required or at least each 5 to 7 year (ref. Sec.3.4 Periodic update of Risk Assessment & IM plans).

4.2 Objective

The risk assessment shall ensure that the safety level premised in the design phase is maintained throughout the original design life of the pipeline system. New technology which documents that the original design has been non-conservative shall be taken into account.

4.3 Basis for Risk Assessment

For application to pipeline systems, the risk assessment should:

— identify all equipment where failure jeopardises the structural integrity of the pipeline system
— for all equipment, identify the potential threats and estimate the risk associated with these
— identify risk reduction mitigations in case of unacceptable risk
— prepare basis for long term inspection planning.

4.3.1 Prevailing documents

Operator guideline

In order to ensure that the risk assessment is done consistently, the risk approach shall be documented. A high level company risk philosophy document should be established which preferably could be applied across different assets, e.g. pipeline systems, offshore structures and plants. This is very important when it comes to communication of risk.

The risk matrix to be applied shall be defined and include (see 4.3.3):

— risk categories and interpretation of these
— acceptable risk level
— probability of failure categories and interpretation of these consequence of failure categories and interpretation of these.

Pipeline system guideline

Asset specific documents aligned with the company philosophy and regulatory requirements shall be established (could be regional dependent). This document may include but is not limited to:

— reference to regulatory requirements
— reference to operator specific requirements and prevailing procedures
— list of threats to be considered for the most common equipment types with reference to best practices
— list of inspection types to be included in the long term inspection plan. Guidance on selection between comparable inspection types should be given
— relevant failure statistics (operator and industry wise).

Best practice

Best practice documents for evaluation of the individual threats or components shall be established. Such document could be established on threat group or component type level. The document should at least contain the following:

— description of the threat and the operator's experience associated with this
— needed input data to address the threats with reference to available data sources
— detailed description of the assessment model. It is strongly recommended to establish a levelled approach; where the conservatism decreases with increasing level. The first level should be a screening level which requires limited amount of input to reach a conclusion
— any limitation to the assessment model with guidance on exceptions
— calculation example for each defined level.

4.3.2 Risk assessment approaches

Different risk assessment approaches can be used. The ASME B31.8S outlines four of them, which are the Subject Matter Experts, the Relative Assessment Models, the Scenario-Based Models and the Probabilistic Models.

Common for all the models is an evaluation of the probability of an event and the consequences that this event will impose.

4.3.3 Risk matrix

The risk matrix shall be defined including annual PoF, CoF and risk categories. The matrix should preferably be defined by the operator and used across different assets, see 4.3.1. An example of a risk matrix is shown in Table 4-1 and the risk categories are defined in Table 4-2.

Work selection matrices should also be defined, e.g. recommended inspection intervals dependent on location in the risk matrix.
4.3.4 Probability of failure modelling

This recommended practice is primarily focused on structural integrity. Failure is caused by an event resulting in either of the following:

— loss of component or system function; or
— deterioration of functional capability to such an extent that the safety of the installation, personnel or environment is significantly reduced.

Such failures occur when the effect of the applied load (L) is greater than the resistance (R) of the component or material (L>R).

The resistance is primarily related to the materials, the design, and the in-service condition of the structure. The load can be any type of load; functional, environmental or accidental. The reasons why L>R occurs are many, ranging from e.g. poor design specification, design errors, and material defects, through to e.g. fabrication errors, degradation in operation, and other unknown events and accidents. The total probability of such a failure is the sum of the probabilities of all events that contributes.

Guidance note:
The total probability of failure (PoFtotal) can basically be summarized as follows:

\[
\text{PoF}_{\text{total}} = \text{PoF}_{\text{technical}} + \text{PoF}_{\text{accidental}} + \text{PoF}_{\text{gross error}} + \text{PoF}_{\text{unknown}}
\]

Where:

- \(\text{PoF}_{\text{technical}}\) - Natural uncertainties in design loads and load bearing capacities. \(\text{PoF}_{\text{technical}}\) is due to fundamental, natural random variability and normal man-made uncertainties.
- \(\text{PoF}_{\text{accidental}}\) - Accidental events. In addition to the functional and environmental loads, there will be “accidental” events that can affect the components, e.g. dropped objects. These accidental load events can be predicted in a probabilistic form based on historical data.
- \(\text{PoF}_{\text{gross error}}\) - Gross errors during design, fabrication, installation, and operation. Gross errors are understood to be human mistakes. Management systems addressing e.g. training, documentation, communication, project specifications and procedures, quality surveillance etc. contribute all to avoid human error. Gross errors occur where these systems are inadequate or are not functioning. It is difficult to predict the probability of a gross error. However, history shows that gross errors are not so rare. Developing, applying and following up the management system in addition to third party checks can help avoiding gross error leading to failure.
- \(\text{PoF}_{\text{unknown}}\) - Unknown and/or highly unexpected phenomena. Truly unimaginable events are very rare, hard to predict and should therefore be a low contribution to failure. There is little value therefore in attempting to estimate these probabilities. It is worth noting that even though incredible events have low probability, they can have very high consequences thus increasing the

---

### Table 4-1 Example of a risk matrix

<table>
<thead>
<tr>
<th>Severity</th>
<th>Safety</th>
<th>Environment</th>
<th>Cost (million Euro)</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>Multiple fatalities</td>
<td>Massive effect, Large damage area, &gt; 100 BBL</td>
<td>&gt; 10</td>
<td>M</td>
<td>H</td>
<td>VH</td>
<td>VH</td>
<td>VH</td>
</tr>
<tr>
<td>D</td>
<td>Single fatality or permanent disability</td>
<td>Major effect, Significant spill response, &lt; 100 BBL</td>
<td>1 - 10</td>
<td>L</td>
<td>M</td>
<td>H</td>
<td>VH</td>
<td>VH</td>
</tr>
<tr>
<td>C</td>
<td>Major injury, long term absence</td>
<td>Localized effect, Spill response, &lt; 50 BBL</td>
<td>0.1 - 1</td>
<td>VL</td>
<td>L</td>
<td>M</td>
<td>H</td>
<td>VH</td>
</tr>
<tr>
<td>B</td>
<td>Slightly injured, a few lost work days</td>
<td>Minor effect, Non-compliance, &lt; 5 BBL</td>
<td>0.01 - 0.1</td>
<td>VL</td>
<td>VL</td>
<td>L</td>
<td>M</td>
<td>H</td>
</tr>
<tr>
<td>A</td>
<td>No or superficial injuries</td>
<td>Slightly effect on the environment, &lt; 1BBL</td>
<td>&lt; 0.01</td>
<td>VL</td>
<td>VL</td>
<td>VL</td>
<td>L</td>
<td>M</td>
</tr>
</tbody>
</table>

### Table 4-2 Example of risk categories

<table>
<thead>
<tr>
<th>Risk</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>VH</td>
<td>Unacceptable risk – immediate action to be taken</td>
</tr>
<tr>
<td>H</td>
<td>Unacceptable risk -- action to be taken</td>
</tr>
<tr>
<td>M</td>
<td>Acceptable risk -- action to reduce the risk may be evaluated</td>
</tr>
<tr>
<td>L</td>
<td>Acceptable risk - Low</td>
</tr>
<tr>
<td>VL</td>
<td>Acceptable risk - Insignificant</td>
</tr>
</tbody>
</table>
The above indicates that using fully probabilistic models to estimate the PoF can become complex and time consuming. More simple qualitative assessments may be used and are generally considered to be sufficient in the context of submarine pipeline integrity management.

The required detailing level depends on the objective of the actual risk assessment e.g. basis for inspection planning or assessment of a critical finding. A levelled approach is therefore recommended and such levels are outlined in the following.

Level 1: Screening level
The probability of failure is typically estimated by evaluating the factors which may contribute to a failure using simple rules. The output is a ranking of risk along the pipeline or risk-ranking between pipelines. This output can then be used to select sections/pipelines for further assessments and act basis for inspection planning.

The input to such a rule based model should be easily obtainable and simple. The rules may address the following:
- loading
- capacity
- degradation possibilities
- IM level
- high level IM results
- operator / industry experience (e.g. failure statistics).

Level 2: Generalized level
The generalized models are more detailed calculation/predictions based on recommended practices to address a specific threat. The models are characterized by:
- a design formulation which gives an allowable quantity - code compliance. The result may be expressed as a relative utilization
- the relative utilization is mapped to probability categories
- the formulation should be applicable for a wide range, i.e., not just a specific location on the pipeline and is therefore setup to provide reasonable conservative predictions of the actual utilization.

If the formulation is based upon a recommended practice which has been calibrated towards specific probability levels, the mapping to probability category is straightforward (e.g., DNV-RP-F105 - Free Spanning Pipelines).

Level 3: Detailed level
This level should reflect state-of-the-art technology. It is typically applied at locations identified with potential high risk in one of the former levels. The estimate of probability of failure at this level may be characterized by:
- detailed analyses at a specific location or for a specific component utilizing the same model as in level 2 but with specific/more accurate input
- more advanced/accurate assessment model (e.g. advanced degradation models, advanced finite element models, results from local/detailed inspections)
- estimation of probability of failure using probabilistic models.

4.3.5 Probability of failure presentation
The output of the probability of failure evaluation is either a numerical value or a probability of failure category. Table 4-3 presents an example where 5 PoF categories are applied and shows how quantitative and qualitative terms can be linked to these.

### Table 4-3 Example of PoF description

<table>
<thead>
<tr>
<th>Rank or Category</th>
<th>Failure probability</th>
<th>Quantitative</th>
<th>Qualitative term</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>$&gt; 10^{-2}$</td>
<td>Very High</td>
<td>Significant</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Failure expected</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Frequent</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Failure has occurred several times a year in location</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>$10^{-3}$ to $10^{-2}$</td>
<td>High</td>
<td>Failure is likely</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Failure has occurred several times a year in operating company</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>$10^{-4}$ to $10^{-3}$</td>
<td>Medium</td>
<td>Normal</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rare</td>
<td>Failure has occurred in operating company</td>
</tr>
<tr>
<td>2</td>
<td>$10^{-5}$ to $10^{-4}$</td>
<td>Low</td>
<td>Remote</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Failure has occurred in the industry</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>$&lt; 10^{-5}$</td>
<td>Very Low</td>
<td>Negligible</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Insignificant</td>
<td>Failure has not occurred in industry</td>
</tr>
</tbody>
</table>

1) The quantitative values are normally related to PoF$_{technical}$ whereas the qualitative values represent qualified engineering judgement that will more or less represent PoF$_{total}$

4.3.6 Consequence of failure modelling
The consequences of a failure are dependent on the failure mode (leak, burst) and physical location. The latter is affected by factors like population, water depth, environmental sensitive area etc.

If the consequences are modelled without consideration of failure mode, e.g. leak or burst, the most severe mode (burst / full bore rupture) shall be assumed.

Assessment of consequences of failure is to take the following into consideration:
- safety (personnel)
- environment
- economy.

Other types of consequences can also be considered as e.g. company reputation.

**Guidance note:**
The safety consequences are based on the average number of personnel present in the area of concern. The parts of a pipeline system close to a platform (within its safety zone), the final consequence is potentially the entire platform population. For the parts of the pipeline system outside the safety zone, the average number of personnel can be based on the level of shipping and vessel activity.

Releases from submarine pipeline systems are most likely to have a significant detrimental impact on the environment. The consequences from an environmental point of view are complex and must not be underestimated. Direct costs related to releases are mainly related to the clean-up costs and fines imposed by authorities. Beside these actual direct environmental consequences, the following elements can be considered related to damaging the environment: Political consequences, Consequences with regard to reputation, Loss of share value.

The economic consequences are mainly related to deferred or reduced production. Costs related to unanticipated intervention, mitigations and repairs can also contribute to the economic consequences.

Important parameters that influence the final consequences are:
- composition of fluid released
---end-of---Guidance---note---

The assessment of consequences may be carried out by describing and modelling scenario/event trees and quantitatively estimating associated probabilities. Applying such methodology with high confidence in the end results requires excessive input and analytical effort. Nevertheless, a better understanding of the possible consequence associated with an event is achieved when setting up such a model.

More simple qualitative assessments may be used and are generally considered to be sufficient in the context of submarine pipeline integrity management. One can distinguish between aggregated and segregated consequence models. Each of these two simple approaches has advantages and disadvantages, see Table 4-5.

### Table 4-4 Product model (example)

<table>
<thead>
<tr>
<th>PRODUCT</th>
<th>SAFETY</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Manned</td>
<td>0 cc</td>
<td>Un-man</td>
<td>D ≤ 8&quot;</td>
<td>D &gt; 8&quot;</td>
<td>D &gt; 16&quot;</td>
<td>D &gt; 32&quot;</td>
<td></td>
</tr>
<tr>
<td>Gas, Well Fluid</td>
<td>E</td>
<td>D</td>
<td>B</td>
<td>B</td>
<td>B</td>
<td>B</td>
<td>C</td>
<td>B</td>
</tr>
<tr>
<td>Gas, Semi-Processed</td>
<td>C</td>
<td>E</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>B</td>
<td>C</td>
</tr>
<tr>
<td>Gas, Dry</td>
<td>D</td>
<td>C</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
</tr>
<tr>
<td>Oil, Well Fluid</td>
<td>E</td>
<td>C</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td>C</td>
</tr>
<tr>
<td>Oil, Semi-Processed</td>
<td>C</td>
<td>B</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td>C</td>
</tr>
<tr>
<td>Oil, Dry</td>
<td>D</td>
<td>C</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td>C</td>
</tr>
<tr>
<td>Condensate, Well Fluid</td>
<td>E</td>
<td>D</td>
<td>B</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td></td>
</tr>
<tr>
<td>Condensate, Semi-Processed</td>
<td>C</td>
<td>E</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td></td>
</tr>
<tr>
<td>Condensate, Dry</td>
<td>C</td>
<td>E</td>
<td>A</td>
<td>B</td>
<td>C</td>
<td>D</td>
<td>E</td>
<td></td>
</tr>
<tr>
<td>Treated Seawater</td>
<td>B</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>B</td>
<td>C</td>
</tr>
<tr>
<td>Raw Seawater</td>
<td>B</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>A</td>
<td>B</td>
<td>C</td>
</tr>
<tr>
<td>Produced Water</td>
<td>B</td>
<td>A</td>
<td>A</td>
<td>B</td>
<td>B</td>
<td>C</td>
<td>A</td>
<td>B</td>
</tr>
</tbody>
</table>

### Table 4-5 Aggregated model vs. segregated model

<table>
<thead>
<tr>
<th></th>
<th>Aggregated model</th>
<th>Segregated model</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Safety/Location Class)</td>
<td>Consistent with safety philosophy adopted in design</td>
<td>Flexible modelling to get the right consequence picture - very important for risk ranking and prioritizing of Inspection, Monitoring and Testing between pipeline systems</td>
</tr>
<tr>
<td></td>
<td>Easy to model the consequences</td>
<td>Possible to mitigate / reduce the consequences</td>
</tr>
<tr>
<td></td>
<td>Target levels for PoF defined</td>
<td>Mitigating action may be dependent on the governing consequence types</td>
</tr>
<tr>
<td>Advantages</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Disadvantages</td>
<td>Less flexible with respect to get a “correct” picture of the consequences</td>
<td>May not be consistent with design philosophy</td>
</tr>
</tbody>
</table>

### 4.3.7 Consequence of failure presentation

Examples of qualitative ranking scales which can be used for the consequence of failure are shown in Table 4-6 (based on ISO 17776), where reputation is also considered, see also example of risk matrix in Table 4-1.
4.4 Developing inspection, monitoring and testing plans

A long term inspection program shall be established in the design phase and implemented in the organisation prior to production start-up. The program shall be verified and if required updated as part of the transfer from design to operation.

The program should document and justify (based on the risk assessment), what, why, how and when an IM-activity shall be performed. This program should typically cover at least 8-years and should be updated when required or at least every 5 to 7 year (see 4.1). Updates may be initiated based on:

— the results from inspection, monitoring and testing activities
— the results from any integrity assessment
— changes in operating parameters or any other changes that may affect the total threat picture
— if any changes occur in the authority requirements or in any other premises and assumptions for the period in question.

4.4.1 Frequency

The frequency of IM-activities will depend on:

— risk level (work selection matrices - normally related to the threat or threat group)
— confidence in input data to the risk assessment
— confidence in integrity status
— evaluation of possible development of the risk.

4.4.2 Workflow diagrams and work selection matrices

It is recommended to establish workflow diagrams and work selection matrices to ensure that consistent actions are taken dependent on the results from the risk assessment.

A typical work selection matrix is inspection intervals dependent on either location in the risk matrix or risk level. An example is shown in Table 4-7.

Workflow diagram is very useful for following up of high risk elements and is a graphic representation of all the major steps of a process. It can help to:

— understand the complete process
— identify the critical stages of a process
— locate problem areas
— show relationships between different steps in a process
— define tools/procedures to be applied
— assign responsibilities
— threat group level, in this case the worst consequence related to the grouped threats apply
— individual threat level, in this case the worst consequence related possible failure modes apply.

A workflow diagram and a description of the different main tasks that the working process consists of are given in Appendix H.

### Table 4-6 CoF Qualitative Ranking Scales

<table>
<thead>
<tr>
<th>Rank</th>
<th>Safety</th>
<th>Assets</th>
<th>Environment</th>
<th>Reputation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/A</td>
<td>Insignificant</td>
<td>Insignificant</td>
<td>Insignificant</td>
<td>Insignificant</td>
</tr>
<tr>
<td>2/B</td>
<td>Slight/Minor Injury</td>
<td>Slight/Minor damage</td>
<td>Slight/Minor effect</td>
<td>Slight/Minor impact</td>
</tr>
<tr>
<td>3/C</td>
<td>Major injury</td>
<td>Local damage</td>
<td>Local effect</td>
<td>Considerable effect</td>
</tr>
<tr>
<td>4/D</td>
<td>Single fatality</td>
<td>Major damage</td>
<td>Major effect</td>
<td>Major national impact</td>
</tr>
<tr>
<td>5/E</td>
<td>Multiple fatalities</td>
<td>Extensive damage</td>
<td>Massive effect</td>
<td>Major international impact</td>
</tr>
</tbody>
</table>

### Table 4-7 Example of work selection matrix - external inspection frequency (years)

<table>
<thead>
<tr>
<th>Severity</th>
<th>Safety</th>
<th>Consequence Categories</th>
<th>Cost (million Euro)</th>
<th>Increasing Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>E</td>
<td>Multiple fatalities</td>
<td>Massive effect Large damage area, &gt; 100 BBL</td>
<td>&gt; 10</td>
<td>3</td>
</tr>
<tr>
<td>D</td>
<td>Single fatality or permanent disability</td>
<td>Major effect Significant spill response, &lt; 100 BBL</td>
<td>1 - 10</td>
<td>8</td>
</tr>
<tr>
<td>C</td>
<td>Major injury, long term absence</td>
<td>Localized effect Spill response, &lt; 50 BBL</td>
<td>0.1 - 1</td>
<td>8</td>
</tr>
<tr>
<td>B</td>
<td>Slightly injured, a few lost work days</td>
<td>Minor effect Non-compliance, &lt; 5 BBL</td>
<td>0.01 - 0.1</td>
<td>8</td>
</tr>
<tr>
<td>A</td>
<td>No or superficial injuries</td>
<td>Slightly affected on the environment, &lt; 1 BBL</td>
<td>&lt; 0.01</td>
<td>8</td>
</tr>
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</table>
5. Inspection, Monitoring and Testing

5.1 General

Plans developed by the 'Risk Assessment and IM-Planning' activity shall form the basis for the detailed planning for the control activities (i.e. inspection, monitoring and testing activities), ref. 3.4. Any deviations from the original plans should be reported and the reason for the deviation established.

Unexpected events may initiate the need for unplanned control activities. To what extent, how and when to carry out these control activities should be handled through the 'Risk Assessment and IM-Planning' activity. This to ensure coordination with other prospective control activities and to evaluate the need for modification of the original strategies.

The detailed plans should be updated on a regular basis and be based on preceding plans and the results achieved from the integrity control activities

**Inspection and monitoring** is defined as condition monitoring activities carried out to collect operational data and other type of information indicating the condition of a component.

**Guidance note:**

_Inspection and monitoring_ as defined in the Oslo Agreement should form the basis for the detailed planning for the control activities (i.e. inspection, monitoring and testing activities). Any deviations from the original plans should be reported and the reason for the deviation should be established.

**Inspection, monitoring and testing of safety equipment** may include the following:

- System pressure testing
- Pressure control equipment
- Over-pressure protection equipment
- Emergency shutdown systems
- Automatic shutdown valves
- Safety equipment in connecting piping systems

**Guidance note:**

Operational data can be physical data such as temperature, pressure, flow, injection volume of chemicals.

For submarine pipelines, maintenance activities are normally covered by the inspection and monitoring program. Maintenance activities are typically cleaning pigging (scraper or chemical treatment) or removal of debris from anodes prior to CP measurements.

Generally, an inspection physically monitors the state of a component directly (e.g. wall thickness, damage to the pipeline), whilst monitoring is the collection of relevant process parameters which indirectly can give information upon the condition of a component.

**Testing** - In the context of integrity management of submarine pipeline systems, testing may include the following:

- System pressure testing (ref. 5.4.1)
- Testing of safety equipment
- Pressure control equipment
- Over-pressure protection equipment
- Emergency shutdown systems
- Automatic shutdown valves
- Safety equipment in connecting piping systems

System pressure testing is not normally applied as a regular integrity control activity. However, there are cases where this might be considered, e.g. if a system has not been designed for pigging operations and the operational conditions have changed in such a way that there are significant uncertainties with regard to the system's structural integrity. In-service system pressure testing may also be carried out in connection with repairs or modifications of the system.

For testing of safety equipment, appropriate standards and codes (used as basis for design) should be utilized. Many designs are based on the e.g. IEC 61508 / IEC 61511 (safety instrumented systems).

Requirements to test intervals as given by the respective authorities should also be adhered to.

An unacceptable situation, mechanical damage or other abnormalities detected (discovered) during the planned control activities shall immediately be reported and subjected for review and the appropriate actions taken. This should be done in order to evaluate if this incident will have impact on the overall strategies and to establish if a re-qualification (ref. 3.6) shall be carried out.

5.2 Recommendations for inspection activities

The purpose for an inspection shall be clearly defined prior to inspection (ref. 4.4).

The main activities associated with the inspection are:

- Detailed planning:
- Execution:
- Reporting and documentation:
- Assessment of the data collected during inspection:

The detailed planning for an inspection (internal or external) includes the following:

- Detailed description of the scope of work:
- Specification of reporting criteria:
- Development of work packages:
- Preparation of work instructions and procedures:
- Establishment of responsibilities and communication lines between inspection Contractor and Operator:
- Procurement of equipment:
- Establishment of plans for the mobilisation of equipment and personnel:
- Carry out risk management activities for the inspection activity:

The execution of the inspection includes the following:

- Mobilisation of personnel and equipment and transportation to the site:
- Carrying out safety activities:
- Complete the inspection:
- De-mobilisation:
- Preliminary reporting towards the specified reporting criteria:

Documentation of the inspection and final reporting of the inspection includes:

- Quality control of the inspection results:
- Issue of final inspection report:

**Guidance note:**

Reporting format: Reporting of inspection results should aim at being in a standardised format to ease the assessment work and to better allow for trending of inspection data as free span measurements, corrosion rates, cover heights etc.

All work instructions, procedures, communication lines and responsibilities, which are mandatory for a safe and cost-effective inspection process, and which constitutes the operation manual, should be implemented as part of the pipeline integrity management system as described in Sec.2.

5.2.1 Inspection capabilities

Pipeline system inspections can be performed either internally or externally as continuous inspections over the entire pipeline length or as local inspections for specific sections or local areas.

Inspection of pipeline systems can be carried out with a wide range of inspection tools having different capabilities and areas of applications. Table 5-1 shows an overview of the most common tools and tool carriers that can be utilised to inspect the various threats to the pipeline system. The table does not give a complete overview of all available tools and their areas of application, as this may vary dependent on various contractors, spread set-up and due to technology development. As a basis for the detailed inspection plan, the available technology, relevant for the specific threat to be inspected for, should be identified by the pipeline operator.

_In-Line inspections (ILI)_ of pipelines are normally carried out using a pig. The pig travels through the pipeline driven by the flow or fluid or may be towed by a vehicle or a cable. It collects...
data as it runs through the pipeline. The tools may be automatic or self-contained or may be operated from outside the pipeline via a data and power link. Different tools can be combined in a pig train. See Appendix E for different inspection methods. 

**External inspections** are normally carried out using a remotely operated carrier equipped with different inspection tools. This can for instance be tools for visual inspections (video recording) and physical measurements (steel electrochemical potential measurements). External inspection can also be performed by divers. See Appendix E for different inspection methods. A description of typical inspection categories often use in connection with inspection planning is given in Table 5-1.

**Guidance note:**
External inspections and associated inspections reports are often denoted 'surveys' and 'survey' reports, respectively. Internal inspections (or In-Line Inspections (ILI)) are associated with intelligent or smart pigs, that uses non-destructive testing techniques to inspect the pipeline. In this recommended practice, the terminology 'inspection' is used both in connection with internal and external inspection.

---end-of-Guidance-note---

<table>
<thead>
<tr>
<th>Threat Group</th>
<th>Threat</th>
<th>ROV</th>
<th>ROTV</th>
<th>Tow–fish</th>
<th>Pig (ILI)</th>
<th>Crawler</th>
<th>Diver</th>
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<td>Construction / material</td>
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<td></td>
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<tr>
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<td>Internal corrosion</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Structural</td>
<td>Free span</td>
<td>× × ×</td>
<td>× ×</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
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<td>× ×</td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Structural</td>
<td>Upheaval buckling</td>
<td>× × × ×</td>
<td>× × × ×</td>
<td>× × ×</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural hazards</td>
<td>Landslides, boulder, scouring etc.</td>
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<td>×</td>
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<tr>
<td>Third party impacts</td>
<td>Anchor, trawling etc.</td>
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<td>× ×</td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Incorrect operation</td>
<td>Incorrect proc, human errors etc.</td>
<td></td>
<td>× ×</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Others?</td>
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</tr>
</tbody>
</table>
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5.2.2 Risk management w.r.t. the inspection operation

Recommendations with regard to risk management in marine and subsea operations can be found in DNV-RP-H101.

Guidelines concerning hazard identification and risk assessment for marine and subsea operations can be found in ISO-17776.

API standard 1163 provides guidance to in-line inspection (ILI) service providers and pipeline Operators employing ILI technology or ‘smart pigs’. The standard provides requirements for qualification of in-line inspection systems used in gas and hazardous liquid lines as well as interpretation of results.

**Guidance note:**

API standard 1163 is an umbrella document that, by reference, incorporates NACE RP 0102 and ASTN ILI-PQ.

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5.2.3 Preparation for inspection

The detailed work description shall be prepared prior to inspection and should include the following as a minimum:

- description of the pipeline system, including any special information important for the inspection/survey (e.g. location of pipeline reducers, branches, changes in wall thickness)
- purpose of the inspection
- specification of required equipment
- detailed description of the equipment and inspection tools
- requirements for calibration of the equipment
- qualification of personnel
- detailed instructions for the inspection including operation procedures
- requirements for documentation of inspection results and/or findings
- preparation of an outline of the inspection report.

Deviations from the annual inspection plan should be explained and documented.

5.2.4 Specification of equipment

The long term inspection program specifies the purpose of the inspection, the type of inspection to be carried out and where to be carried out. It may e.g. specify intelligent pigging using MFL, or external ROV. Further specification of the required equipment needs to be addressed when planning a specific inspection in detail. This should be done as part of the detail planning (ref. Fig. 3-3). The accuracy of the selected methodology should be considered.

**In-line Inspections**

The following information will typically be required when preparing for a pigging operation:

- what to inspect for:
  - wall thickness loss
  - cracks
  - dents
  - internal or external corrosion attacks
  - launcher and receiver dimensions
  - inner diameter for the entire system
  - pipeline length
  - pipeline wall thickness
  - linpipe material
  - internal cladding or lining, if applicable
  - elevation profile
  - data (as location, dimensions) on bends, tees, wyes, valves, etc.
  - pipeline content, pressure, temperature, fluid velocity.

**External Surveys**

The following information will typically be required when preparing for an external survey:

- What to inspect for:
  - the CP system - looking for abnormal consumption of the anode mass.
  - indication of inadequate coverage or potential from the CP system leading to excessive corrosion
  - damages or cracks in coating or concrete
  - general damage to structures and pipelines from impact (dropped object, equipment handling, anchor impact or dragging, fishing, etc.)
  - burial depth
  - freespan
  - flanges and hubs - looking for leaks
  - pipelines - looking for upheaval buckling or snaking
  - settling or excavation of templates or manifolds resulting in an increased stress level for the pipeline
  - pipeline support - ensuring that rock-dumps are intact and that the pipeline remains positioned within the intended support area
  - pipeline configuration
  - water depth
  - crossings
  - pipeline components.
5.2.5 Listings and digital reporting

The amounts of collected data from one single survey either externally or internally can be significant. Most data are reported in so-called “listings”. Listings may contain information as (measured as a function of KP or easting/northing):

- time and date
- KP (distance)
- Easting and Northing positions
- wall thickness (only for ILI)
- seabed configuration, average seabed profile, trenches, rock dumpings
- scouring
- location and condition of mattresses, sleepers, protection structures
- location of components like valves and flanges
- free span length, gap, shoulders
- debris, mines, ship wrecks, fishing equipment, etc.
- coating damage
- events like dents, leakage, unintended exposure, upheaval buckling
- CP recordings
- offset or sliding marks in the seabed caused by the pipeline.

“Listings” should be in a digital format. To obtain good quality in survey reporting, it is important that listings are in a consistent format. The format should be selected based upon the amount of data-recorded, specification for data formatting and available software.

5.2.6 Inspection report

Inspection reports are normally issued as first-hand reports shortly after the inspection and as final inspection reports later on. In most cases, these reports contain the same type of information (and conclusions) but are issued at different times. However, some adjustments of the inspection results may appear after a more detailed assessment of the results has been performed.

External inspection reports

After an inspection, a report including a printout of the listings (first hand report, final report) should always be issued. This report should typically contain information on the following:

- scope of the inspection
- survey vessel
- description of inspection tools and equipment and calibration certificates
- acceptance criteria
- accuracy and confidence level for the selected inspection method
- reference to relevant procedures for the inspection
- pipeline information, geometrical data like diameter, wall thickness, coating etc.
- KP definitions
- coverage of survey
- UTM coordinates and conversion algorithm applied
- operational conditions in the pipeline, like measured temperature, pressure and flow-rates and flow direction including location of measurement equipment
- date and time, KP
- seabed configuration
- explanation of expression and terms, symbols used in reports and listings
- sea state (current, waves etc.) during survey
- Digital Terrain Models (DTM), KP database or alignment sheets used to plan the survey and used during the survey
- data recorded on-line and off-line, post processing, manipulation and smoothening of data
- threshold or cut-off levels for reporting (like limiting free
- span length, gap)
- listings of findings
- findings that exceed acceptance criteria
- listing of deviations from plans.

Instead of printing all listings in the survey report, the report should summaries the information similar to what is listed in the bullet points above.

The report should also include:

- definitions and an explanation on how the data shall be read and interpreted
- cross reference to digital reports (file name), charts, drawings, pictures and videos delivered should be given.

Internal inspection reports

Finding from internal inspections should be reported in such a manner that it allows for comparison between different campaigns and thereof the possibility of revealing any development of i.e. metal loss over time (i.e. trending). The document “Specifications and requirements for intelligent pig inspection of pipelines” /3/ developed by The Pipeline Operator Forum (POF) gives operational and reporting specifications and requirements for tools to be used for geometric measurements, pipeline routing, metal loss, crack or other defect detections reported during the inspection campaign.

5.2.7 Review of inspection results

In addition to the report from the inspection contractors, which might include an assessment of the results, the operator should make a high level evaluation of the inspection and the results. This evaluation should address:

- if the inspection has been done according to the plan which describes what, how and when to inspect.
- the quality of the inspection (i.e. confidence in results)
- a high level evaluation of the inspection results with respect to the integrity (e.g. classified as insignificant, moderate, significant, severe findings)
- recommendation for further assessment of the findings.

5.3 Recommendations for monitoring activities

Monitoring is the measurement and collection of process data that indirectly can give information on the condition of a component or a system.

The monitoring data is typically either on-line measurements or offline measurements (scheduled).

The main activities associated with monitoring are:

- description of the purpose of the monitoring
- data acquisition and storage
- retrieval and analysis of data
- documentation and reporting, including comparison against acceptance criteria.

5.3.1 Monitoring capabilities

The techniques for condition monitoring can either be on-line or off-line. On-line monitoring represents continuous and/or real-time measurements of parameters of interest. Off-line monitoring would typically be scheduled sampling with subsequent analysis at e.g. a laboratory.

Monitoring can be performed by direct and indirect techniques.

Guidance note:

With regard to corrosion, direct techniques typically measure the corrosion attack or metal loss at a certain location in the pipeline system utilising corrosion probes, whilst indirect techniques measure parameters that affect the corrosion (e.g. O2 content).
Monitoring is further classified as intrusive or non-intrusive. An intrusive method will require access through the pipe wall for measurements to be made, whilst a non-intrusive technique is performed externally (will not require access through the wall thickness) or analysis of sample data taken from the process stream.

The most common monitoring techniques are related to monitoring of:
- chemical composition (e.g. CO₂, H₂S, water)
- process parameters (e.g. P, T, flow)
- external or internal corrosion
- internal erosion (i.e. sand)
- current and vibrations
- ship traffic and fishing activity
- land movement
- leak detection.

5.3.2 Corrosion monitoring
The rate of corrosion dictates for how long any process equipment can be safely operated. The corrosion monitoring techniques can help in several ways such as:
- by providing an early warning of possible changes in corrosion rate
- trending of changes in process parameters and the corresponding effect on the corrosivity
- monitoring the effectiveness of the implemented corrosion preventive means as e.g. chemical inhibition.

Monitoring of external corrosion
Pipelines are protected from external corrosion by coatings (primary protective means) and cathodic protection (secondary protective means). Cathodic protection is typically done by using sacrificial anodes for submarine pipelines and impressed current for onshore pipelines. Visual inspection is regularly carried out for detecting coating damages. Monitoring of galvanic anodes is done by e.g. measurement of anode potential and current output or measurement of electrical field, ref. Appendix C.4.1.

Monitoring of internal corrosion and erosion
Monitoring techniques for corrosion monitoring and sand management are typically:
- monitoring probes:
  - Electrical Resistance (ER) probes
  - weight loss coupons
  - Linear Polarisation Resistance (LPR) probes
  - hydrogen probes
  - field Signature Method (FSM) spools located at low spots to measure local corrosion
- sampling
  - samples of debris gathered by running cleaning or scraper pigs
  - samples of the fluid
  - sand monitoring devices (e.g. sand detection and monitoring probes, non-intrusive acoustic detectors).

Monitoring of internal corrosion is further described in Appendix C.4.4

Guidance note:
Since ER-probes, LPR-probes and weight loss coupons normally are located topside, the value of the recordings are discussed. However, recordings from such probes will enable the Operator to trend any major changes in the corrosivity of the medium and thus the likelihood for an increased uniform corrosion rate to occur. It will not be able to disclose local corrosion attacks.

---end-of---Guidance---note---
depth or location of sub-critical flaws
— the method does not verify that the acceptance criteria are fulfilled (e.g. wall thickness)
— it normally requires the pipeline to be taken out-of service for the testing
— it may be a challenge to remove water from the pipeline following a hydrostatic pressure test. Such residual water would have the potential for initiating internal corrosion.

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ASME B31.8 and DNV-OS-F101 give requirements to the execution of a pressure test.

5.4.2 Hydrostatic Testing

Hydrostatic testing requires water within the pipeline to be pressurized beyond the maximum operating pressure, and then maintained to determine if there are any leaks. Typically, the pressures are raised to 125% of the maximum allowable operating pressure or more and maintained for 8 to 24 hours. The operational integrity of welds and the pipe is assured if the hydrostatic test is successfully passed.

Hydrostatic pressure testing requires that detailed procedures for treatment of the water to be used in the pressure test and drying of the pipeline system subsequent to the testing are developed and approved prior to the pressure testing commences.

5.4.3 Gas or Media Testing

Gas: Pressure testing with an inert gas or with the produced or processed flowing media is also possible. Testing with gas may increase the likelihood of a rupture rather than a leak should a failure occur during the test. For this reason, gas testing is often limited to short lengths of pipe.

Media: Pressure testing to demonstrate the integrity of a line with the produced or processed flowing media could be attractive if the likelihood of a test failure is small. When testing with the flowing media, some gas may be used to boost the pressure. There is an increased risk of a rupture when significant volumes of gas are required.

5.4.4 Shut-In Testing

In addition to elevated pressure testing, shut-in leak tests are sometimes used. During such a test, the pressure is shut in for the time needed to detect a leak of a given size (leak rate). Shut-in tests are more common in liquid lines, where leaks are usually easier to record, provided the media is (nearly) incompressible. Long hold times are required for shut-in tests for small leaks.

5.4.5 Pressure Testing Limitations

There are concerns that any elevated pressure test could enable sub-critical pipe imperfections and cracks to increase in size; and consequently subsequently fail under a pressure below the test pressure. In these cases, the line is exposed for a short time to a spike pressure above that used during the rest of the test. The spike pressure is intended to remove any near-critical flaws that might grow during the subsequent hold period at a lower pressure.

A limitation of pressure testing is that it provides no information on the location or even the existence of sub-critical flaws. The time required for a sub-critical flaw to grow to critical dimensions increases as the ratio of test pressure to operating pressure increases. At low test pressures (i.e., near the operating pressure), little or no safety margin is provided.

5.4.6 Review of test results

A review of the test plan shall be done on annual basis to ensure that planned testing has been conducted and that the results from such are take into consideration.
6. Integrity Assessment

6.1 General

When a potentially unacceptable damage or abnormality is observed or detected, an integrity assessment shall be performed. This shall include a thorough evaluation of the damage/abnormality and the possible impact on the safety for further operation of the pipeline.

An overview of damages/anomalies associated with the different threats to a submarine pipeline system is given in Table 6-1. Long term inspection plans developed by the Risk Assessment and IM Planning shall form the basis for any integrity assessment (ref. Sec.3.4).

When a damage/anomaly is observed, the details of the damage/anomaly shall be quantified taking accuracy and uncertainties of measurements into consideration, and the cause(s) shall be identified. Additional inspection, monitoring and testing may be necessary.

If the damage/anomaly is evaluated to be unacceptable, necessary information shall be reported as input to the updated risk assessment where overall plans with regard to mitigation, intervention and repairs should be developed.

Pipeline systems with unacceptable damage / anomalies may be operated temporarily under the design conditions or reduced operational conditions until the defect has been removed or repair has be carried out. It must, however, be documented that the pipeline integrity and the specific safety level is maintained, which may include reduced operational conditions and/or temporary precautions.

An overview of available assessment codes for the most common damages/anomalies is given in Table 6-1. For assessment of global buckling, reference is given to Appendix B and for internal and external corrosion, reference is given to Appendix C.

<table>
<thead>
<tr>
<th>Damage/ anomaly</th>
<th>Code / Guideline</th>
<th>Comment</th>
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<td>Metal loss</td>
<td>DNV-RP-F101</td>
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<td></td>
<td>ASME B31.G</td>
<td>Including the “modified edition”</td>
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<td></td>
<td>PDAM</td>
<td>Summarises most common methods</td>
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<td>DNV-OS-F101</td>
<td>Acceptance criteria and allowable dent depth</td>
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<td></td>
<td>DNV-RP-F113</td>
<td>Pipeline repair</td>
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<tr>
<td></td>
<td>DNV-RP-C203</td>
<td>Fatigue</td>
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<tr>
<td></td>
<td>EPRG / PDAM*</td>
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</tr>
<tr>
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<td>DNV-OS-F101</td>
<td>Detailed ECA analyses required</td>
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<td>Guide on methods for assessing the acceptability of flaws in metallic structures</td>
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<td>Global buckling of Submarine Pipelines</td>
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<td>On-bottom stability</td>
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<td>Coating damage</td>
<td>DNV-RP-F102</td>
<td>Coating repair</td>
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<tr>
<td>Anode damage</td>
<td>DNV-RP-F103</td>
<td>Cathodic protection</td>
</tr>
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</table>

*) PDAM: Pipeline Defect Assessment Manual
EPRG: European Pipeline Resource Group

The integrity assessment process shall be based on historical data. Fig. 6-1 gives an example of the different activities that produce data needed for the integrity assessment.

The integrity assessment may be split into:

- corrosion assessment covering internal and external corrosion
- mechanical assessment covering e.g. fatigue in freespan, displacement causing overstress, third party damage causing extreme strains.

The data achieved from such activities shall be properly documented to ensure traceability and enable trending.
6.2 Un-piggable pipelines

Un-piggable pipelines are those that do not allow a standard inspection tool to pass through. The reason for not being piggable could be:

- variations in pipe diameter
- over- or under-sized valves
- short radius or mitred bends
- repair sections in a different size
- no permanent pig launcher/receiver or possibilities for connection of temporary launcher/receiver.

Un-piggable pipelines are subjected to separate evaluations and alternative methods and are not covered herein.
7. Mitigation, Intervention and Repair

7.1 General

Long term inspection plans or event based inspection plans developed by the 'Risk Assessment and IM Planning' should form the basis for mitigation, intervention and repair activities (ref. Sec.3.4).

Mitigating activities are measures taken to reduce the likelihood of failure or the consequence of failure.

Pipeline intervention activities are mainly corrective actions related to the external pipeline seabed interaction and support conditions (e.g. trenching, rock-dumping).

Pipeline repair are mainly corrective actions with the objective to restore compliance with requirements related to functionality, structural integrity and / or pressure containment of the pipeline system.

In some cases there may be a need for technology qualification of the above activities prior to execution. This can for instance be qualifying of intervention tools, qualification of a repair clamp or of new chemical.

Mitigation, intervention and repair activities shall not impair the safety level of the pipeline system below the specified safety level, as defined in design.

Overall requirements related to mitigation, intervention and repair are given in Sec.11 of DNV-OS-F101.

Generally, the main activities are:

— detailed planning of the operation
— technology qualification if necessary
— mobilisation
— execution of the operation which will include transportation to site, safety activities, coordination activities, meetings, tests, drills, completion, NDT and testing, de-mobilisation and close-out activities, etc.
— documentation.

All mitigations, interventions and repairs shall be carried out by experienced and qualified personnel in accordance with agreed procedures.

Intervention may introduce new constraint to the system which must be assessed and approved by relevant disciplines before initiation. Typical aspects to be assessed are 3rd party protection, pipeline integrity with the new constraints and load scenarios, and corrosion protection.

All interventions and repairs shall be verified / tested and inspected by experienced and qualified personnel in accordance with agreed procedures. NDT personnel, equipment, methods, and acceptance criteria shall be agreed upon in accordance with appropriate standards and codes.

Guidance note:

DNV-RP-F113 outlines such a procedure to qualify the integrity and functionality of a repaired section - including e.g. NDT procedures, local leak tests through test ports, recording of governing parameters (bolt pretension level, welding parameters).

The need for system pressure test after completion of a repair operation depends on governing design code, company requirements and the qualification of the repair method.

7.2 Detailed planning

Detailed planning shall take into consideration authority regulations. The purpose of a specific action or operation shall be established prior to any detailed planning. This is normally carried out as a part of the development of mitigation, intervention and repair strategies - see 3.2. Detailed planning shall include:

— a detailed definition of the scope of work
— if necessary, detailed specification of selected actions / method needs to be completed. This will depend on the mitigation, intervention and repair strategy provided by the Risk Assessment and the IM-planning activity
— preparation of detailed procedures for the operation
— establishment of responsibilities and communication lines between involved parties
— carry out risk management activities
— establishment of plans for mobilisation of the intervention and repair activity
— logistics and coordination
— carrying out the repair or intervention
— NDT and Leak testing if applicable
— documentation of the operation
— communicate the status of the operation to the risk review and strategy development activity.

7.2.1 Risk management w.r.t. mitigation, intervention and repair

Typical aspects to be considered with regards to risk management:

— operating envelopes during the operation (e.g. to be performed during hot or cold condition)
— risk of 3rd party damage from the operation itself
— HAZOP for the different parts of the action / operation
— potential consequences of the action / operation to the overall pipeline system.

Recommendations with regards to risk management can be found in:

— DNV-RP-F107 (Risk assessment of pipeline protection)
— DNV-RP-H101 (Risk management in marine and subsea operations)
— Guidelines on tools and techniques for hazard identification and risk assessment can be found in ISO-17776.

Guidance note:

DNV-RP-F107 “Risk assessment of pipeline protection” gives a risk based approach for assessing pipeline protection against accidental external loads. Recommendations are given for damage capacity of pipelines and alternative protection measures and assessment of damage frequency and consequence.

7.3 Mitigation means

Typical means of mitigating activities are:

— Restriction in operational parameters such as MAOP, inlet temperature, flow rate, and number of given amplitudes of these (e.g. shut-downs).

Such restrictions may have impact on the set-point value for the pressure protection system or the pressure regulating system.

— Use of chemicals in order to mitigate corrosion rate, flow improver, reduce scaling, avoid hydrate formation.

— Maintenance pigging with the objective of removing scale, deposits, liquid accumulated in sag bends. May also include temporary increased flow rate to flush out local accumulated liquid or particles.

7.4 Intervention means

Pipeline intervention is typically used to control:

— thermal axial expansion causing lateral or upheaval buckling,
— on bottom stability,
— protection against third party damage
— to provide thermal insulation
— to reduce free span length and gaps
Typical means of intervention are:
- rock dumping
- pipeline protections against 3rd party (mattresses, grout bags, protection structures, gravel cover)
- trenching.

**7.5 Repair methods**

The most suitable method for pipeline repair depends on the extent and mechanism of the damage, pipe material, pipe dimension, location of the damage, load condition, pressure and temperature.

The purpose of a repair is to restore the pipeline safety level by reinforcing the damaged section or to replace the damaged section. A repair may be temporary or permanent; depending upon the extent of the damage. A temporary repair may be acceptable until the permanent repair can be carried out. In case of a temporary repair, it shall be documented that the pipeline integrity and safety level is maintained either by the temporary repair itself and/or in combination with other precautions (e.g. reduced pressure or flow rate).

The following repair methods may be used:
- The damaged portion of the pipe is cut out and a new pipe spool is installed either by welding or by a mechanical connector.
- Local repair by installation of a repair clamp externally on the pipeline. The type and functional requirement of the repair clamp depends on damage mechanism to be repaired. Structural clamps are qualified to accommodate specified pipe wall axial and radial load, whereas leak clamps provide sealing in case of leak inside the clamp.

Leaking flanges and couplings may be sealed by installing:
- a seal clamp covering the leaking flange
- installing a new coupling
- increasing the bolt pre-load
- replacing gaskets and seals.

Prior to increasing the pre-load in bolts, it shall be documented by calculation that no over-stressing occurs in bolts, flange or gasket and seals. In case the pre-load in the bolts is removed, e.g. due to changing of gasket, new bolts shall be used for the flange connection.

All repair clamps, sleeves, pipe spools and mechanical connectors shall be qualified to governing design premises and codes prior to installation and leak tested after installation.

**Guidance note:**

For guidance upon pipeline subsea repair, reference is made to DNV-RP-F113 (Pipeline Subsea Repair), which gives description of different pipeline repair equipment and tools, their application, qualification principles to be used, pipeline interaction forces to be designed for, design principles and guidelines, requirements related to mechanical sealing, hyperbaric welding, test philosophy relevant for the different phases of repair equipment qualification and documentation requirements. Design and qualification guidelines for hot tap fittings and plug applications are also given in DNV-RP-F113.

---end-of-Guidance-note---

**7.6 Detailed procedures**

Execution of mitigation activities, intervention and repair operations can be complex. This is illustrated by the typical sequence of activities involved in a pipeline section replacement repair operation:

- emptying, or isolating the location with isolation plugs
- sea bed intervention (e.g. excavation, gravel filling), for access and to provide stable support condition for pipeline support and alignment tools
- cutting and removal of weight and corrosion coating
- cleaning, close visual inspection and NDT of damage, as required
- restraining and supporting the pipeline prior to cutting (e.g. by H-frames)
- cutting and removing the damaged section
- onshore detailed inspection of the damaged section
- preparation and inspection of pipe ends at seabed, to comply with the repair tool specification
- installation of new pipeline section and connecting the ends after required alignment by use of the repair tool. (Marine operation procedure required, e.g. buoyancy elements, jacking from the seabed or lifting assistance from support vessel, tie-in and alignment tools, mounting frame and if welding habitats)
- retrieval of installation tools and equipment
- commissioning of repair operation (e.g. NDT, leak test)
- protection over repaired section (e.g. cover, gravel bags or mattresses) against 3rd party interference
- pressure testing.

For all these sub-activities, detailed procedures shall be prepared; e.g. for the repair operations, the detailed procedures should typically include:

- project procedures defining repair project organisation, the roles, responsibilities and communication lines between all parties involved
- procedures for emptying and cleaning the pipeline prior to cutting of pipe section
- emergency preparedness plans for the operation
- procedures for seabed interventions
- procedure for required marine operation, including restrictions related to weather window
- pipeline repair procedures
- NDT and leak test procedures
- procedures for protection of the repair location against 3rd party loads.
APPENDIX A
PIPELINE STATISTICS, FACTS AND FIGURES

A.1 Objective
Statistical data on incidents reported in the North Sea and the Gulf of Mexico has been analysed and compared in order to find out the main causes of failures. The statistics will only include steel pipelines related to rigid steel lines, that is flexible pipelines are not included.

A.2 Introduction
The presented statistical graphs for the incidents in the North Sea are based on PARLOC 2001 /1/, which is a comprehensive report made by The Institute of Petroleum, UKOOA and HSE, UK. A total of 1069 steel lines are operating in the North Sea.

Data on pipeline failures in the Gulf of Mexico is based on a DNV technical report on Risk Assessment /2/. The lengths of the pipelines in the Gulf of Mexico are 32 447 km and 50% of the pipelines are piggeable, whereas only 5% are smart piggable.

The statistical data are grouped in incidents with leakage and incidents with and without leakage.

The most reported fault is caused by corrosion with 27% reported incidents in the North Sea and 40% in the Gulf of Mexico. 85% and 45% of the corrosion problems in the Gulf of Mexico and the North Sea, respectively, are related to internal corrosion. In addition fittings, flanges and valves failures are a large problem.

A.3 Results and discussions
It is reported 1069 steel lines operating in the North Sea and a total of 65 incidents which resulted in a leakage have been reported between the years 1971 to 2001. The causes of the incidents can be viewed in a sector diagram in Fig. A-1. As can be deduced from the figure, 40% of the accidents were related to corrosion which again can be divided in external and internal corrosion, with 7 and 14 incidents respectively. Five incidents were not specified and were therefore reported as unknown.

17 incidents were related to anchor (12%) and impact damages (14%). Trawling is the main cause for impacts and were mostly located in the mid line area, whereas anchoring damages caused by ships and supply boats were located in the safety zone. The material damages were related to weld and steel defects.

No data on incidents related to leakage in the Gulf of Mexico were reported.

Figure A-1
Operating steel pipelines incidents resulting in leakages in the North Sea /1/.

*) Incidents related to fittings are not included. Incidents compared with pipelines incidents resulting in leakage are only 7% and therefore not the dominant pipeline failure.

Corrosion incidents are the main cause of failures on steel pipelines and Fig. A-2 gives an overview of the pipelines where the different types of corrosion incidents were located. The highest frequency of external corrosion incidents occurred on the risers in the splash zone, whereas most of the internal corrosion failures were located in the mid line of the steel pipelines. The unknown corrosion incidents are randomly distributed along the pipelines.

![Figure A-2](Location of corrosion failures on steel pipelines /1/)

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**DET NORSKE VERITAS**
The percentage distributions of failures on pipelines with and without leakage are shown in Fig. A-3a. Still corrosion is of great importance when it comes to incidents in the North Sea, however it is clear that impact and anchor damages are dominating the statistics. For the Gulf of Mexico incidents related to corrosion, natural hazards and other are the main failures, see Fig. A-3b. “Other” is typical unknown failures and failures related to fittings and flanges.

Based on reports from the North Sea /1/ and the Gulf of Mexico /2/ some of the most dominating incidents are listed below:

- corrosion (internal and external)
- impact (trawling, fishing activities)
- anchor
- other (fitting, valves and unknown causes)
- natural hazard (mudslides, hurricanes, scour etc.)

For the Gulf of Mexico failures caused by natural hazards are the second most dominating with 17% of total registered failures. The amount of damages related to anchoring is only 6%. The reason for this is probably because all pipelines in the Gulf of Mexico shall be buried, therefore the damages caused by impact and anchor are less than those for the North Sea.

As previous mentioned the main failure causing damages on pipelines is corrosion. In a technical report produced by DNV /2/ 40% of the failures causing leakage in the Gulf of Mexico was due to corrosion, whereas internal corrosion was represented with 81%. Fig. A-4 shows a percentage comparison of failures due to corrosion in the North Sea and the Gulf of Mexico. Internal corrosion is the dominating type of damages related to corrosion.

A.4 Conclusions

The main fault on pipelines in the North Sea and the Gulf of Mexico is caused by internal corrosion. Anchoring and impact related damages are not so dominating in the Gulf of Mexico, probably because the pipelines are buried. A large source to failures is those related to fittings and flanges, and as much as 30% of reported incidents in the North Sea are related to fittings and flanges. However, only 7% gave leakage. For the Gulf of Mexico 10% of the reported failures are caused by fittings, flanges and valves.

A.5 References

APPENDIX B
RECOMMENDATIONS WITH REGARD TO GLOBAL BUCKLING

B.1 Introduction

Pipelines, like other slender constructions with compressive forces, can buckle globally given the right conditions. The axial compression force is normally caused by temperature and internal pressure (expansion effects).

Global buckling is likely when the so-called effective axial force from pressure and temperature reaches a certain level. For a buried pipeline, this level is also influenced by the cover that is supposed to be sufficiently strong to resist the uplift generated by the axial forces.

Global buckling is a threat that needs to be managed by the integrity management process. As described in the main body of this recommended practice, the integrity management process comprises the following main activities:

— Risk Assessment and Inspection Planning
— Inspection, Monitoring and Testing
— Re-qualification / Integrity Assessment
— Mitigation, Intervention and Repair.

The following provides recommendations to the different parts of the integrity management process with regard to global buckling as a threat it is applicable primarily for rigid pipelines.

B.2 Risk Assessment and Integrity Management Planning

B.2.1 Establishing and transferring integrity

The activity of developing strategies for the other integrity management process activities should start gathering relevant information as early as within the concept phase. In most cases, evaluations relevant to the global buckling threat will already start taking place in e.g. feasibility studies carried out during the concept phase. With regard to global buckling, the system risk review and strategy development activity should be initiated by participating in such early studies.

System risk reviews carried out throughout the concept, design and construction phases as a part of the development project should also be followed up by the responsible for the system risk review and strategy development activity.

The system risk review and strategy development activity should:

— give feedback to any design activities affecting global buckling as a threat.
— give feedback to the development of DFI resumes w.r.t. global buckling as a threat. Information of particular importance for handover from design to operation is presented in Table B-1.

### Table B-1 Outlined Integrity Transfer Log - Global Buckling

<table>
<thead>
<tr>
<th>Information</th>
</tr>
</thead>
<tbody>
<tr>
<td>GENERAL INFORMATION</td>
</tr>
<tr>
<td>Why the pipeline buried or left exposed.</td>
</tr>
<tr>
<td>Surveys carried out</td>
</tr>
<tr>
<td>Strategy for inspection &amp; monitoring</td>
</tr>
<tr>
<td>High focus areas</td>
</tr>
<tr>
<td>Reference values (as installation temperature, pressure, content)</td>
</tr>
<tr>
<td>Temperature and pressure profiles that reflect expected operational conditions and design values</td>
</tr>
<tr>
<td>Limitations from design (as design temperature, pressure)</td>
</tr>
</tbody>
</table>

B.2.2 The global buckling threat

Exposed Pipelines

Global buckling (lateral or upheaval/uplift) for an exposed pipeline is not necessarily a failure. Whether or not it is a failure needs to be established through a condition assessment focusing primarily on pipeline utilization, but also on pipeline displacement.

The loading/utilization of the pipeline is closely linked to the curvature in the pipeline. A sharp curvature normally implies high utilisation. The loading can be expressed as a bending moment [kNm], strains on the compressive or tensile side [%] or stresses [MPa]. The most relevant failure modes that are directly related to utilization / curvature are (for more details see DNV-OS-F101 Sec.5D):

— **Local buckling**: which is normally the governing failure mode resulting from excessive utilization. Local buckling appears as wrinkling or as a local buckle on the compressive side of the cross section. Local buckling can lead to excessive ovalisation and reduced cross-section area. This means reduced production, or even full production stop if e.g. a pig should get stuck. A locally buckled pipeline can not stand an increased bending moment in the pipeline. This could lead to pipeline collapse and full production stop.

— **Loss of containment**: as a result of:

  — **Fracture** is failure on the tensile side of the cross-section also resulting from excessive utilization. Fracture leads to leakage or full bore rupture, meaning reduced
production, or even full production stop.

- **Low cycle fatigue** can occur for limited load cycles in case each cycle gives strains in the plastic region; i.e. the utilization is excessive in periods. Low cycle fatigue may lead to leakage or rupture, meaning reduced production, or full production stop.

- **Hydrogen induced stress cracking (HISC)** can occur in martensitic steels (13%Cr) and ferritic-austenitic steels (duplex and super-duplex). Blisters of free hydrogen can create cracks in steel or weld at a CP/-anode location when the steel is exposed to seawater and stresses from the buckle. The pipeline utilization does not have to necessarily be excessive. HISC leads to leakage or full bore rupture, meaning reduced production, or full production stop. For more on HISC, see DNV-RP-F112 /4/.

Examples of unacceptable displacement are:

- displacement of in-line tees
- displacement of valves
- interference with other pipelines
- interference with other structures
- skidding off free span supports
- unwanted uplift at crests
- pipeline walking.

**Buried Pipelines**

For buried pipelines, buckling occurs as upheaval buckling that may or may not protrude out of the seabed as an arc. Upheaval buckling of buried pipelines is normally an unacceptable condition and is considered a failure on its own. Otherwise, the same failure modes related to excessive utilization/curvature, as for exposed pipelines, apply for an up-heaval buckling. Additional threats for any exposed part can be:

- fatigue damage (in the upward free spanning pipeline caused by vortex shedding vibrations)
- hooking of fishing equipment or interference with other third party loads
- excessive strains and low cycle fatigue.

Without documentation of the integrity of the pipeline upheaval, the upheaval shall immediately be considered as a failure.

For more details see DNV-OS-F101 Sec.5D.

**Guidance note:**

The reason for normally considering upheaval buckling as unacceptable is simply that most buried pipelines are designed to stay in place. This may be because of law and regulations, to protect the pipeline against 3rd party activities such as trawl gear interference or dropped objects, to ensure stability, to avoid free spans, for insulation purposes, due to an unstable seabed, to limit expansion of the pipeline itself or basically to avoid the pipeline to buckle upward. Experience has shown that the loading in the pipeline during upheaval buckles can be critically high. Evaluation of observed upheaval buckles shows longitudinal strains in the same order as for pipelines during reeling, up to 3-4%. This can be critical for the pressure containment itself. Once the decision is made to bury a pipeline, the cover/lateral restraint shall be designed to avoid global buckling of the pipeline. This may be done either by trenching or leaving it on the seabed, then covering it by natural or artificial back-filling, see Fig. B-1.

The potential for upheaval buckling failure is normally highest when exposed to maximum temperature and pressure (design values). Temperature and pressure will create a compressive effective axial force in the pipeline. An out of straightness will result in forces on the soil, perpendicular to the pipeline. An upheaval buckle will appear at the location where the uplift forces exceed the resistance. Hence, the integrity threats are caused by insufficient soil resistance and/or excessive expansion forces.

--- end of Guidance note ---

**Key parameters & factors**

Key parameters and factors are listed below:

- **Maximum potential effective axial force** - For submerged pipelines, the term effective axial force is normally applied. Effective axial force depends on cross section properties, material properties, pressure, temperature, \( \Delta T \) (temperature difference relative to as laid) and \( \Delta p_i \) (internal pressure difference relative to as laid) are the main contributors. The cross section parameters (especially the bending stiffness (EI)) influence the shape and the length of the buckling mode. Increased diameter (EI) will lead to increased axial forces.

**Imperfections** - Pipelines will normally include imperfections both in the vertical and the horizontal plane. These are important when evaluating global buckling, mainly for the following two reasons:

- The degree of imperfection will significantly influence the buckling load and the buckling process. With no or minor imperfections, the buckling occurs suddenly and with a distinct “snap through” behaviour. If relatively large imperfections are included, the displacements develop more gradually.

- The shape and type of imperfection will influence the post buckling displacement pattern.

- **Axial feed-in to in buckled areas** - In the post buckling condition, any additional pipeline expansion will be fed axially towards the buckling location and the buckle will adjust accordingly. The axial feed-in is therefore a crucial parameter for the post buckling behaviour as bending moment/strain and lateral displacement will increase by increasing axial feed-in. The governing parameters regarding axial feed-in and the buckling length, and the buckling pattern (distance between buckles).

- **Lateral resistance** - Lateral resistance is the product of submerged weight and lateral friction. For a given axial feed-in, high lateral resistance tends to give “narrow” shaped buckling mode with corresponding high bending moment in apex. Low lateral resistance gives a wider buckling mode shape and lower bending moment.

- **Axial resistance** - The product of submerged weight and axial friction. Axial resistance does not influence the response in the buckle directly. But since the axial response affect the axial feed-in and the global buckling pattern (distance between each buckle), the parameter may be important. Large axial resistance will trigger relatively many buckling locations. Many buckling locations are normally beneficial (the total axial expansion can be shared by many buckles).

- **Vertical resistance (upheaval buckling)** - the resistance provided by the cover.

- **Pipe-soil interaction** - Pipe-soil interaction parameters are in general very important when evaluating global buckling of pipelines. Here, pipe-soil interaction is indirectly included via axial and lateral resistance.

- **Hoop utilisation** - high utilisation in hoop direction (due to high inner pressure or high D/t ratio) tends to decrease the allowable bending moment.

- **Corrosion** - Any significant corrosion will decrease the allowable bending moment.

- **Effect of varying operating conditions** - Cyclic loading, e.g. due to repeated start-ups and shut-downs. Normally, varying operating conditions have a limited effect on lines not susceptible to buckling. For lines that are susceptible to buckling, the cyclic loading may influence the pipeline behaviour significantly:

  - **Cyclic loading** may lead to fatigue / low cycle fatigue or ratcheting.

  - **Long free spans in shut-down condition** - Smaller diameter lines are more sensitive to this effect than

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lines with larger diameters. Long free spans may be exposed to VIV/fatigue. In addition, the likelihood for 3rd party loads may increase (e.g. from trawl gear interference).

— **Unwanted large displacement or buckling at unwanted locations** - Repeated load cycles will normally cause a change of buckling configuration. Compared to the 1st time of buckling, the lateral buckling mode shape tends to be wider after some cycles. Though this leads to reduced bending moment/axial stress in apex, a wider mode shape will also lead to increased and possibly unwanted lateral displacements. There may also be cases where more significant changes occur after some cycles, e.g. new, possibly unwanted, buckling locations occur.

— **End expansion.** A pipeline tends to expand toward its ends due to pressure and temperature increase. Excessive end expansion may cause unwanted high deformation of end terminations, in rigid spools, flexible tails, riser bases etc.

— **Pipeline walking** is a denotation for a situation where the pipeline globally shifts position in the axial direction. Pipeline walking is related to transient temperature during start up of the pipeline and:
  - has limited anchoring in the axial direction, or
  - lays on a slope, or
  - is pulled in one end, as the tension from a steel catenary riser.

— **Pipeline walking** may also be an issue for a pipeline with global buckles with limited axial anchoring in between two adjacent buckles.

### B.3 Inspection, monitoring and testing

#### B.3.1 Inspection

The configuration of a global buckling pipeline will normally change with operational conditions and over time. The global buckling condition should be assessed focusing primarily on pipeline utilization, but also on pipeline displacement - see Appendix B.2.2. Inspection is the primary tool for establishing the necessary information needed.

**General recommendations:**

— The main purpose of the survey should be to identify global buckles and define their curvature.
— Carry out a reference survey before the pipeline is put into operation.
— Regularly carry out inspection with regard to global buckling. Note that the inspections are often more frequent in the first few years of operation.
— Monitor and report the operational conditions prior to and during any such surveys. The monitoring period should start 48 hours before the survey. For more information about monitoring parameters, see B.3.2
— Document whether the reported configuration is related to the position of the survey vessel or the pipeline
— Inherent and achieved survey accuracy should be recorded
— Calibration of the survey equipment is in all cases important and should be documented.

**Recommendations specific for exposed pipelines:**

— Surveys of an exposed pipeline with a global buckling potential should focus on addressing the configuration of the pipeline both in the horizontal plane and in the vertical plane.
— The configuration of the pipeline should preferably be given together with the seabed.

**Recommendations specific for buried pipelines:**

— She survey(s) carried out on the as-installed and/or as trenched pipeline and used as the basis for designing the required cover should be considered as the reference survey(s).
— To be able to fully document the integrity of a buried pipeline, both the pipeline configuration and the height of the cover should be measured.

**Recommendations wrt development of strategies and plans for inspection:**

— Inspection planning should reflect the long term development of temperature and pressure in the pipeline.
— A pipeline with increasing operational conditions may require frequent inspection, whereas a pipeline with decreasing operational conditions, the first year of operation is the most critical requiring most of the attention.
— Though buried pipelines are designed to stay in place different processes can affect the stability:
  - creep in the soils due to variations in operational conditions
  - erosion process reducing the cover.
— Events/factors that can affect both planned and unplanned inspection can be:
  - large variations in operational conditions
  - exceeding the design conditions
  - hooking by trawl gear or anchor interference / emergency anchoring
  - storm, hurricanes, storm surges or flooding from river mouth that can cause erosion
  - earth quakes
  - subsidence.

**Inspection tools:**

— An inspection is normally carried out through external ROV surveys (e.g. cross profiler, multi beam and pipe tracker). Some external survey tools have range limitations. Pipelines buried deep into the soil may e.g. not be able to be inspected by using seabed surface survey techniques.
— High quality tools like geo-pigs can provide accurate measurements of the configuration, but the survey may have limited value unless it can be linked to the seabed topology and/or the soil cover.
— The survey of a buried pipeline can be carried out applying different techniques depending on the inspection philosophy. For pipelines with high temperature and pressure, an upheaval buckling failure will most likely result in an arc rising out of the seabed. For this case, visual inspections, side-scan sonar and similar methods can reveal an upheaval buckling failure. In some soils, creep effects can occur, i.e. the pipeline can shift its position due to cyclic loadings. This may be a case for low temperature and pressure pipelines. Such cases would require more comprehensive survey techniques

**Guidance note:**

For some exposed pipelines, skidding marks can be visible on the seabed. These marks can provide a measure of changes in operational conditions. Erosion processes or soil settlements may erase marks in the soil over time.

Displacement of the pipeline can be measured through marks on the seabed such as piles or rocks. Such methods may be crucial for measuring axial displacement such as end displacements, feed-in to global buckles or pipeline walking.
B.3.2 Monitoring

During operation, the following key parameters should be monitored:

- inlet temperature and pressure
- outlet temperature and pressure (optional)
- flowrate.

Recording of historic maximum/minimum values, variations in temperature and pressure (e.g. shutdowns) and actual values during survey should be made.

**Guidance note:**

Global buckling in a pipeline is a local behaviour and is governed by the functional loads within the anchor zone for each buckle. These functional loads are temperature, pressure and weight of the internal content. The local temperature and pressure along the pipeline are often described in profiles. The temperature and pressure profiles are normally related to a set of inlet or outlet values. These reference values are in many cases measured and recorded. The physical location of temperature sensors and pressure gauges are often within the pipeline system but seldom in the pipeline itself. Hence, the reference point for a sensor shall be described and the relation between the values at the reference point and the corresponding values in the pipeline given. A temperature and pressure profile can be described based on (minimum) the inlet temperature, the inlet pressure and the flow rate.

The pressure profile changes according to the column weight and the friction. The temperature profile relates to the insulation, the external temperature and the flow rate. The initiation and post-buckling behaviour is governed by the loads locally in the pipeline, i.e. the temperature and pressure with the anchor-zone for each buckle.

---end-of-Guidance-note---

B.4 Integrity Assessment

B.4.1 Acceptance criteria

Global buckling in a pipeline is not a failure in itself, except for upheaval buckling. Possible failure is related to excessive curvature in a global buckle. Hence, the acceptance criteria for a global buckle are related to utilisation of the cross section. The potential failure modes are local buckling, fracture, low cycle fatigue and HISC, see B.2.2.2. Depending on the governing failure mode the acceptance criteria will be given in different formats; either as strain, curvature or bending, stresses or a bending moment.

The bending loads, curvature, strain or stresses in the pipeline can be estimated in a FE-model and then be evaluated against the acceptance criteria. Using FE-models to evaluate the integrity may be time consuming and is in many cases not necessary to perform. A screening criterion that can be related to survey results should be developed to assess the majority of observed global buckles. Global buckles that do not pass the screening criterion, or due to other reasons can not be assessed with a screening criterion, should be addressed to a FE-analysis.

In case the acceptance criterion is maximum allowable moment or stress, the transformation can be found in FE-simulation of the actual cross-section.

---Figure B-1---

Possible scenarios for covered/restrained pipeline

This relation is basis for all global buckling analyses using FE-models, see Fig. B-2. It is important that the relation is established for applicable internal pressures, temperature and material properties ($\Delta p_{i1} > \Delta p_{i2} > \Delta p_{i3}$).

---Figure B-2---

Relation between acceptable strain and bending moment
B.4.2 Exposed pipeline
Condition assessment of exposed pipelines is recommended split into four steps and certain steps are recommended levelled going from a simple assessment into more complex in-depth analysis.

— Step 1 Identify global buckles
— Step 2 Condition assessment of each buckle as observed (levelled)
— Step 3 Condition of measures/sharing criteria
— Step 4 Condition of pipeline for changing operational conditions (levelled)

The three first steps (1), (2) and (3) are based upon survey measurements of the pipeline and the installed seabed measures. Together with knowledge of the operational condition during a survey these steps can be followed to document the integrity of the pipeline as observed by the survey.

Step (4) is an integrity prediction based on other operational conditions, including e.g. future design condition.

The procedure starting point is based upon observations made from survey data, through numerical processing of survey data and finally supported by finite element simulations.

The condition assessment can stop at the first level if there is access to detailed data, and extensive knowledge and experience. This is the case if e.g. a qualified and experienced team has access to:

— analyses and accept criteria from the design phase that are properly documented in a comprehensible manner
— well defined and documented operational temperature and pressure loads
— well defined and documented historical survey data.

The condition assessment can also stop at the first level if e.g. the pipeline is a stationary pipeline that does not change configuration over time.

An in-depth assessment may be required in the cases where e.g. there is lack of acceptance criteria, significant uncertainties in design data, frequent changes in operational conditions or if global buckling is not addressed by design.

B.4.3 Buried pipelines

B.4.3.1 Evaluation of buried pipeline
Upheaval buckling in a buried pipeline is related to failure in the soil. Hence, the condition assessment of a buried pipeline is mainly related to measurement of the cover. The required cover height shall be given from design as a function of KP - see Table B-1.

The actual cover height is best evaluated as the measured distance from the pipeline to the seabed. Preferably, this measure is made in the same survey. It can be difficult to perform surveys of good quality for buried pipeline. Hence, any comparison between the as-laid or as-trenched pipeline will give valuable information.

The potential for experiencing upheaval buckling is at its peak for the design loads. Failure will occur at the “weakest point” (the combination of pipeline imperfection, soil resistance and functional loads). A pipeline can be considered “field proven” for the highest historical operational loads.

B.4.3.2 Evaluation of pipeline with upheaval buckle
A pipeline that fails due to upheaval buckling will in many cases be standing like an arc out of the seabed. The height and length of this arc can be significant; lengths of up to 50 meters and heights of up to 5 meters have been recorded. Failures can also occur within the soil and not be visible on the surface. An upheaval buckle is likely to have high strain values.

An upheaval must be checked for potential for new failure modes, as fatigue in the free span, hooking of fishing equipment, excessive ovalisation, fracture and local buckling. In many cases, the integrity of an upheaval can not be documented and intervention is often required.

B.5 Mitigation, intervention and repair

B.5.1 Mitigation
Mitigating actions are actions that reduce the likelihood or consequence of failure.

Examples of possible mitigation actions are:

— lowering the temperature or pressure
— carrying out maintenance pigging in order to improve flow conditions
— limitations regarding future start ups and shut-downs in case of high strain values.

Any such actions should be designed to fit the purpose, and any resulting new threats should be evaluated.

B.5.2 Intervention
Pipeline intervention actions are mainly rectifying actions related to the external pipeline constraints.

An unacceptable global buckling condition (excessive utilization or unacceptable displacement) is normally repaired buy using different intervention techniques.

Different seabed intervention means can be used during the operational phase to correct and limit certain behaviour/expansion in connection to global buckling. Trenching, rock dumping, mattresses and buoyancy elements are some options with regard to exposed pipelines - see Table B-2. For buried pipeline, additional trenching or backfilling can be possible solutions. A soil cover on top of an upheaval buckle can be designed to restrain / lock the pipeline in its new position. In many cases, the pipeline will have released its compressive axial force in the area close to the upheaval. This should be taken into account when designing the new cover.

Any such mean should be designed to fit the purpose, and any resulting new threats should be evaluated.

<table>
<thead>
<tr>
<th>Measure</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal curve</td>
<td>Initiate global buckle in a horizontal curve</td>
</tr>
<tr>
<td>Snake lay</td>
<td>Systematic laying of pipeline in curves with a specified interval, each curve is meant to initiate a global buckle</td>
</tr>
<tr>
<td>Trigger berms</td>
<td>Pre-installed rock berms that shall initiate global buckling at given location</td>
</tr>
<tr>
<td>Skidding carpets of rock</td>
<td>Pre-installed rock carpets. Installed in areas where buckling is predicted to occur. The purpose is to limit uncertainties with regard to pipe-soil interaction or to reduce the absolute soil resistance.</td>
</tr>
<tr>
<td>Sleepers</td>
<td>Pre-installed bars installed to initiate global buckling at the actual location. Sleepers are often made of spare pipe-joints and installed perpendicular to the pipeline. To avoid sinking into the soil some are equipped with a foundation. The pipeline may skid on the sleeper, or balance on the sleeper as a turn point for the lateral deflection.</td>
</tr>
</tbody>
</table>
B.5.3 Repair

Pipeline repair are mainly rectifying actions to maintain compliance with requirements related to structural integrity and/or pressure containment of the pipeline. If a global buckle leads to a loss of containment, more comprehensive repair methods shall be used. Any repair should be designed to fit the purpose, and any resulting new threats should be evaluated.

B.6 References

/3/ Det Norske Veritas DNV-RP-F112’ Design of Duplex Stainless Steel Subsea Equipment Exposed to Cathodic Protection’

<table>
<thead>
<tr>
<th>Measure</th>
<th>Purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trenching</td>
<td>Limiting or avoiding lateral buckling.</td>
</tr>
<tr>
<td>Axial restraints/rock dump</td>
<td>Rock berms installed on top of pipeline to restrain a global axial displacement at the actual location. They can be used to limit end expansion, prevent excessive feed-in into a buckle. Ensure that two adjacent buckles both are initiated.</td>
</tr>
<tr>
<td>Uplift resistance</td>
<td>Rock dump or mattresses installed to prevent pipeline to lift up and buckle at specific locations.</td>
</tr>
<tr>
<td>Additional Buoyancy</td>
<td>Buoyancy element or coating installed on the pipeline to reduce the weight and friction against the soil. The purpose can be to easy initiation of buckles and to make to smoother curvature in post buckling condition.</td>
</tr>
</tbody>
</table>
APPENDIX C
RECOMMENDATIONS WITH REGARD TO CORROSION

C.1 Objectives
The objectives of Appendix C is to given an overview of different corrosion threats commonly associated with submarine pipelines for oil and gas production, and applicable techniques for inspection of corrosion control systems and recommendations regarding corrosion monitoring.

C.2 Introduction
Corrosion threats to a pipeline system shall be managed by the integrity management process.

The integrity management process (Ref. Sec.3) comprises of the following main activities:
- Risk Assessment and IM Planning (Sec.4)
- Inspection, Monitoring and Testing (Sec.5)
- Integrity Assessment (Sec.6)
- Mitigation, Intervention and Repair (Sec.7).

Relevant corrosion threats will depend on the linepipe and pipeline components materials, fluid corrosivity and efficiency of options for corrosion mitigation. Materials in corrosion resistant alloys and carbon steel internally lined or clad with a corrosion resistant alloy (CRA) are considered fully resistant to CO2-corrosion in an oil and gas production system. Duplex and martensitic stainless steel linepipe and pipeline components require special considerations of the susceptibility of environmentally assisted cracking, primarily related to (HISC).

Guidance note:
Alloys resistant to CO2-corrosion: Type 13Cr martensitic materials, 22Cr and 25Cr duplex stainless steel and austenitic Ni-based alloy

Table C-1 gives an overview of the most common corrosion threats.

C.3 Risk Assessment and Integrity Management Planning

C.3.1 Establishing and transferring integrity
System risk reviews (DNV-OS-F101 Sec.2 B300) shall be carried out throughout the concept, design and construction phases. Personnel responsible for the system risk review and strategy development activity should attend these reviews.

Identification of relevant corrosion threats will already take place during the conceptual design phase as part of the preliminary materials selection and determination of the pipe wall thickness. The need for internal corrosion control and provisions for inspection and monitoring will in that respect also be assessed. The system risk review and strategy development activity should therefore be initiated during the conceptual design and followed up in the subsequent design phases.

The system risk review and strategy development activity should provide input to the DFI resumes with regards to corrosion threats and provisions for corrosion mitigation and corrosion monitoring.

C.3.1.1 Design of Corrosion Monitoring Systems

Techniques and equipment for corrosion monitoring shall be selected based upon (ref. DNV-OS-F101, Sec.11 D504):
- monitoring objectives, including requirements for accuracy and sensitivity
- Fluid corrosivity and the corrosion preventive measure to be applied
- Potential corrosion mechanism

A risk assessment analysis can be used for: identifying the relevant corrosion mechanisms, their associated corrosion forms (e.g. pitting, uniform attack), high risk areas and be the basis for the design of the corrosion monitoring program.

If it is planned for chemical injection to mitigate corrosion, the criticality in terms of regularity of the injections, any need for backup injection systems or spare equipment, should also be evaluated.

The corrosion monitoring methods and fluid analyses that are most suitable for monitoring the corrosion or fluid corrosivity should be established, considering their accuracy and sensitivity.

The most suitable location of any monitoring device should be established during design, such that the monitoring devices are able to detect any changes in the fluid corrosivity (e.g. located in the areas with hold-up and drop-out of water). However, for submarine pipelines, this is normally considered a challenge.

Since a pipeline is inaccessible over its total length, monitoring of the internal condition of the pipeline may be restricted to monitoring of the process parameters, chemical injection rate for corrosion mitigation and by intrusive and non-intrusive methods located in accessible areas, typically at pipeline outlet (top side) or at the manifold. However, it is also possible to monitor a submerged section of the pipeline by the installation of instrumented spools installed inline the pipelines (see guidance note). The location of the instrumented spool must be carefully selected, such that the area most susceptible to corrosion is selected (e.g. low point areas, areas were water drop out is expected).

Guidance note:
The field signature method (FSM) is a non-intrusive monitoring method which makes it possible to monitor changes in the pipe wall in real-time at pre-defined locations along a subsea pipeline.

Since this system can only monitor specific locations along the pipeline, the location of the FSM should be carefully selected and be located at critical points.

C.3.1.2 Inspection
Corrosion monitoring does not give information of actual loss of wall thickness in the pipeline and can therefore not replace the in-line inspection of the pipeline system. It is therefore important that inspection options are considered early during the design phase and preferably during the concept phase. For minimum requirements with regard to pigging, see DNV-OS-F101.

C.3.2 Risk assessment and strategy development

External and internal corrosion may lead to loss of containment by pinhole leak to full bore rupture. The process leading to the loss of containment will vary depending on the corrosion mechanism. The various tables provided in this appendix contain information that can be used in connection with risk assessments as described in Sec.4.
Table C-1  Common corrosion threats

<table>
<thead>
<tr>
<th>Corrosion Threat</th>
<th>Initiator</th>
<th>External See Note 1</th>
<th>Internal See Note 3</th>
<th>Time dependency</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>O₂-corrosion</td>
<td>O₂ + water</td>
<td>o</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>CO₂-corrosion</td>
<td>CO₂ + water</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3, 7</td>
</tr>
<tr>
<td>Top of line corrosion</td>
<td>CO₂ + water</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3, 7</td>
</tr>
<tr>
<td>Preferential weld corrosion</td>
<td>CO₂ + water</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3, 7</td>
</tr>
<tr>
<td>General H₂S-corrosion</td>
<td>H₂S + water</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 2, 3</td>
</tr>
<tr>
<td>Sulphides stress cracking (SSC)</td>
<td>H₂S + water</td>
<td>(×)</td>
<td>(×)</td>
<td>Abrupt</td>
<td>1, 2, 3</td>
</tr>
<tr>
<td>Stress corrosion cracking (SCC)</td>
<td>H₂S + chloride/oxidant + water</td>
<td>(×)</td>
<td>(×)</td>
<td>Abrupt</td>
<td>1, 2, 3</td>
</tr>
<tr>
<td>Hydrogen induced cracking (e.g. HIC)</td>
<td>H₂S + water</td>
<td>(×)</td>
<td>(×)</td>
<td>Abrupt</td>
<td>1, 2, 3</td>
</tr>
<tr>
<td>Microbiologically induced corrosion (MIC)</td>
<td>Bacteria + water + organic matter often in combination with deposit</td>
<td>o</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3, 4</td>
</tr>
<tr>
<td>Corrosion-erosion</td>
<td>Produced sand + O₂ / CO₂ + water</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>Under deposit corrosion</td>
<td>O₂ / CO₂ + water + debris/scaling</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>Galvanic corrosion</td>
<td>O₂ / CO₂ + water</td>
<td>o</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>Elemental sulphur</td>
<td>(H₂S + O₂ + water) / (S + water)</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>Carry-over of glycol</td>
<td>(H₂S +O₂ + water) / (CO₂ + water)</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3</td>
</tr>
<tr>
<td>Hydrogen induced stress cracking (HSIC)</td>
<td>Cathodic protection + load/stress + susceptible material</td>
<td>×</td>
<td>NA</td>
<td>Abrupt</td>
<td>1, 3, 5</td>
</tr>
<tr>
<td>Acid corrosion</td>
<td>Acid</td>
<td>NA</td>
<td>x</td>
<td>Time dependent</td>
<td>1, 3, 6</td>
</tr>
</tbody>
</table>

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1) External corrosion of submarine pipeline shall be controlled by the application of external corrosion coating in combination with cathodic protection (CP). Galvanic corrosion will be eliminated by cathodic protection.

2) Corrosion control through materials selection and qualification according to ISO-15156. Applicable both for internal and external corrosion.

3) Aggravating factors with regards to internal corrosion may be:
   - Presence of organic acids
   - Scaling and deposits in the pipeline

4) Of primary concern is sulphate reduced bacteria (SRB). SRB’s produces H₂S through their metabolism. See Note 2.

5) Susceptible linepipe materials are: 13Cr, 22Cr, 25Cr and high strength steels

6) Chemicals for cleaning of the pipeline internally

7) Corrosion resistant alloys are considered fully resistant to CO₂ corrosion in an oil and gas production system

NA = not applicable
× = probable threat
× = very low probability due to the general requirement for materials resistance to sour service under such conditions (see also note 2)

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C.4.1 Inspection of external corrosion

External inspection includes to a large extent inspection of the external corrosion protection system. Most often is the inspection limited to look for coating deficiency and the condition of the galvanic anodes.

Inspection for any suspected external corrosion should be carried out by wall thickness measurements. Inspection for external corrosion may be triggered if there is significant uncertainties concerning the external corrosion protection system or if the external corrosion protection system has failed.

Guidance note:

External corrosion protection system of submarine pipelines includes the application of a pipeline and field joint coating and cathodic protection (CP). Cathodic protection can be obtained by the use of galvanic anodes or by an impressed current system (i.e. submerged zone and buried zone). For submerged pipelines, cathodic protection by galvanic anodes is almost always the preferred system, whilst impressed current is normally used on onshore pipeline. In areas where cathodic protection is not feasible (i.e. splash zone and atmospheric zone), a corrosion allowance is normally applied to compensate for external corrosion.

The objective of monitoring and inspecting the external corrosion protection system is to confirm that the system functions properly and to look for any shortcomings caused by installation or during operation (Ref. DNV-OS F101).

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End of Guidance note.

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Inspection of the external corrosion protection system of pipelines with a galvanic cathodic protection system can include:

- visual inspection of the external coating condition
- visual inspection of the condition and consumption of the galvanic anodes
- potential measurements of galvanic anodes
- steel-to-electrolyte potential measurements along the pipeline
- potential measurements at any coating damage exposing bare pipe metal
- electric field gradient measurements and current densities in the vicinity of the pipe
- anode current output.

Buried/rockdumped pipelines are in principle inaccessible for visual inspection and direct potential measurements. Inspection of these pipelines may be limited to inspection of exposed sections of the pipeline at pipeline ends and any possible gal-

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Excessive anode consumption is indicative of coating deficiencies and corrosion damage (rust). Coating damage may be investigated through visual inspection or with the use of cameras. Anodic consumption may be assessed by measuring the anode dimensions or by the amount of anode material consumed. Damage to anode fastening cables may also be inspected visually.

Most of the instrumentation used for portable surveys involves reference electrodes for potential measurements, current density coupons, and anode potential monitoring shunts. Portable equipment such as a metal tip probe and reference electrode located adjacent to the pipeline, or a ROV, may be used. Monitoring of galvanic anodes may include:

- Electrical field gradient survey
- Potential survey
- “Drop-cell survey”
- “Trailing wire survey” / “weighted-electrode survey”

Visual examination may include inspection of:

- damage to anode fastening cables
- anode consumptions (assessment of anode dimensions)
- measurements of anode dimensions
- identification of missing or damaged anodes
- coating damage
- corrosion damage (rust).

Potential survey - The effectiveness of the CP-system can only be assessed by measuring the actual pipe-to-seawater potential. Commonly used survey methods to obtain the pipe-to-seawater potential along the pipeline are by:

- “Direct contact measurements”;
  Measurement of the pipe-to-seawater potential difference with a voltmeter by direct contact with the steel via a metal tip probe and a reference electrode located adjacent to the steel surface
- “Drop-cell survey”;
  An electrical connection to the riser above the water line is established and a reference electrode is to be lowered into the water and positioned along the side of a structure by a cable at different elevation, by a diver or by a ROV (applicable for risers).
- “Trailing wire survey” / “weighted-electrode survey”;
  An electrical connection with a wire to the pipeline at the riser above the water line is established. A ‘towed fish’ with a reference electrode connected to a survey vessel and a wire is positioned over the pipeline and moved along the pipeline route (by a vessel, ROV or diver) where the potential versus distance is measured.

Remote electrode survey

A remote reference electrode (remote earth) is used to measure the potential between the pipe and a remote electrode (an electrode is remote when the distance between the electrode and the pipeline is such that change of electrode position do not change the measured potential between the electrode and the pipeline). The remote electrode can be located on the ROV unibiblical or below the survey vessel hull. The fixed voltage offset between the pipeline and the remote electrode must be established prior to the survey by a calibration contact measurement to the pipeline.

Electrical field gradient survey

The same electrodes used for measuring electrical field gradients (EFG in $\mu V/cm$) along the pipeline can also be used to obtain pipe-to-seawater potential.

Electrical field gradient survey - The electrical field gradient (EFG in $\mu V/cm$) method measures the voltage difference between two reference electrodes separated at a constant distance. The electrical field close to the pipeline and anode will vary due to the CP-currents in the seawater. The measurements can be used to assess the current density levels on anodes (for semi-quantitative assessments of anode current outputs), locate coating defects and to convert the measurements into pipe-to-seawater potentials.

Monitoring and inspection of galvanic anodes - Galvanic anodes can be monitored by direct and in-direct techniques. Direct techniques include direct measurement of anode potential and current output. Indirect measurement includes measurement of the electrical field in order to assess the anode current output and potential level in the vicinity (close to) of the anode.

Monitoring techniques for the condition and performance of galvanic anodes may include:

- anode ‘stab’ measurement for anode potential measurement
- electrical field gradient measurements – can be used for

---end-of---Guidance---note---

With the exception of the two buried zones, the corrosion zones can further be defined as “external” or “internal”. Internal atmospheric, splash and submerged zones may apply e.g. in platform shafts and in land fall tunnels. Pipelines in tunnels and entrances are sometimes grouted but the corrosion zones defined above are still applicable.

Visual inspection - Visual inspection of unburied section of a pipeline can be performed by a diver or with an ROV equipped with a camera. Visual examination may include inspection of:

- damage to anode fastening cables
- anode consumptions (assessment of anode dimensions)
- measurements of anode dimensions
- identification of missing or damaged anodes
- coating damage
- corrosion damage (rust).

Excessive anode consumption is indicative of coating deficiencies, except close to platforms, templates and other structures where current drain may lead to premature consumption of adjacent pipeline anodes. Low anode consumption can indicate passivation of the galvanic anode.

Apparent rust or discoloration of the steel is indicative of under-protection of the pipe.
— semi-quantitative measurement of the anode current output
— installation of anode current monitoring shunt for quantification of anode current output
— induction coil meters for determination of anode current output.

Initial Survey - A visual post lay survey should preferably be performed to look for any damage to the coating and the CP-system caused by installation. The survey can also include the determination of the potential along the pipeline and current output of galvanic anodes from field gradient measurement which can be used as a baseline for later surveys. If a post lay survey is not feasible, a survey of the external corrosion protection system should at least be carried out within one year of installation (OS F101).

Impressed current CP systems - For pipelines or pipeline sections (e.g. landfalls) with an impressed current cathodic protection system, reference is made to applicable sections in ISO-15589-1 and NACE SP0207 for monitoring and inspection of such systems.

Requirements for calibration of equipment - All equipment used for potential measurements shall be calibrated. For the calibration of reference electrodes reference is made to NACE Standard TM 0497 or an equivalent standard.

C.4.2 Inspection of internal corrosion
Internal inspection of pipeline systems to monitor a time dependant internal corrosion mechanism will require wall thickness measurement. Wall thickness measurement can be performed by:
— intelligent pigging equipped with UT and MFL
— wall thickness measurements by portable NDT equipment or permanently installed NDT equipment. Measurements are taken from the external surface at a specific location.

C.4.3 Inspection of abrupt corrosion threats
Abrupt corrosion threats are typically stress corrosion cracking mechanisms and hydrogen induced cracking. ROV inspection and intelligent pigging can be used to identify such cracking. However, due to the abrupt nature of such damages, regular inspection of such failures is normally not carried out. See Sec.6 for more details regarding inspection methods.

C.4.4 Monitoring
C.4.4.1 General
The objective of internal corrosion monitoring is to confirm that a fluid remain non-corrosive or to evaluate the efficiency of the corrosion preventative measures.

Guidance note:
Corrosion monitoring can also be used to diagnose any prospective corrosion problem in the system (e.g. MIC), for determination of inspection schedules and extended service life assessments.

Pipelines in corrosion resistant alloys are considered resistant to CO₂-corrosion. For such systems, monitoring could be restricted to condition monitoring of process parameters and scheduled monitoring of fluid composition. CMn- and low alloy steel linepipe material, which are not resistant to CO₂-corrosion, will in addition, require monitoring of the internal corrosion and the corrosivity of the fluid.

Corrosion monitoring of pipelines carrying non corrosive fluid (e.g. dry gas) could be restricted to monitoring of the water dew point (ref. DNV-OS F101).

Corrosion monitoring does not give information of actual loss of wall thickness in the pipeline and can therefore not replace the in-line inspection of the pipeline system.

C.4.4.2 Corrosion Surveillance
Corrosion surveillance includes activities related to condition monitoring and corrosion monitoring and comprises of:
— monitoring process parameters (e.g. pressure)
— fluid analysis (e.g. of corrosive species)
— monitoring aiming to control the corrosion (e.g. corrosion inhibitor, dew point)
— use of corrosion probes or other more sophisticated monitoring techniques
— chemical analysis of corrosion product (e.g. on corrosion probes, debris collected after cleaning)
— integrity monitoring (wall thickness measurements by permanently installed equipment or used at a specific location).

The objective of the corrosion surveillance is to detect any operational changes, changes in the fluid corrosivity and incipient corrosion that may lead to a potential threat to the pipeline.

C.4.4.3 Corrosion monitoring techniques
The techniques for corrosion monitoring can either be on-line or off-line. On-line monitoring represents continuous and/or real-time measurements of the parameter of interest, whilst off-line monitoring would typically be scheduled sampling with subsequent analysis at e.g. a laboratory.

Corrosion monitoring can be performed by direct and indirect techniques. Direct techniques measure the metal loss or corrosion at a certain location in the pipeline system (e.g. corrosion probes), whilst indirect techniques measure parameters that affect the corrosion (e.g. O₂ content) or the outcome of the corrosion (remaining wall thickness by NDT methods).

Corrosion monitoring is further classified as an intrusive or non-intrusive. An intrusive method will require access through the pipe wall for measurements to be made (e.g. corrosion probes), whilst a non-intrusive technique is performed externally (will not require access through the wall thickness) or analysis of samples taken from of the process stream.

Intrusive techniques used to monitor the corrosion in the system are related to a specific location and are most suitable to monitor overall changes in fluid the corrosivity.

Non-intrusive methods in terms of scheduled sampling are suitable for monitoring any possible changes in the fluid corrosivity over time.

Non-intrusive indirect techniques for wall thickness measurements should be performed at the same location when using portable equipment in order to monitor any prospective development in the corrosion.

Table C-2 shows examples of different corrosion monitoring techniques.
### C.4.4.4 Typical monitoring parameters

The extent of fluid analysis will depend on the fluid composition and the use of chemical treatment for limiting the corrosion in the pipeline. Table C-3 gives an overview of typical monitoring parameters to be considered in connection with planning and implementation of a corrosion monitoring program for a pipeline.

Use of chemicals for corrosion control shall always include monitoring of the efficiency of the chemical injection. It is worth nothing that the lists above can be extended to include other parameters. This will depend on the particular need for a specific pipeline system.

### C.5 Integrity Assessment

#### C.5.1 Corroded pipelines

For integrity assessments of corroded pipelines, ref. DNV-RP-F101 /20/.

#### C.5.2 Assessment of integrity of cathodic protection system

The cathodic protection potential criteria as given by the design code (or the CP-design code applied) shall be maintained throughout the design life.

### C.6 Mitigation, intervention and repair

#### C.6.1 Mitigation

The main mitigation action is corrosion control improvements. Corrosion control includes measures taken to limit the corrosion in the pipeline. This may include the use of chemical injections (e.g. inhibition) or the need for scheduled cleaning of the pipeline (see Table C-4).

#### C.6.2 Intervention

Intervention is not usually applied as a measure against corrosion. Potential cases where it may be considered as an option are:

- removal of debris that may damage the external corrosion protection system
- carrying out intervention in order to limit or reduce stresses on the pipeline.

#### C.6.3 Repair

Corrosion can lead to a loss of containment requiring repairs. An integrity assessment of a corroded pipeline may conclude that repairs are required in order to prevent a loss of containment - See Sec.8 for more on pipeline repairs.

---

<table>
<thead>
<tr>
<th>Monitoring techniques</th>
<th>Classification</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corrosion probes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Weight loss coupons</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>(Flush mounted or probes extended into the fluid)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Linear Polarisation</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>Resistance (LPR)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electrical Resistance</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>(ER)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrogen probes</td>
<td>In-direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>Galvanic probes</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>Biopores</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>Advance electrochemical techniques</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Impedance spectroscopy</td>
<td>Direct</td>
<td>Intrusive</td>
</tr>
<tr>
<td>Electrochemical noise</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fluid analysis</td>
<td></td>
<td></td>
</tr>
<tr>
<td>For details see Appendix D</td>
<td>In-direct</td>
<td>Non-intrusive</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field signature method</td>
<td>Direct</td>
<td>Non-intrusive</td>
</tr>
<tr>
<td>NDT (Ultrasonic testing UT)</td>
<td>Direct</td>
<td>Non-intrusive</td>
</tr>
<tr>
<td>Radiography</td>
<td>Direct</td>
<td>Non-intrusive</td>
</tr>
<tr>
<td>Video camera/ boroscope</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Identification of corrosion damage</td>
<td>-</td>
<td>‘Intrusive’</td>
</tr>
<tr>
<td>Long range ultrasound/ guided wave</td>
<td>Screening technique for identification of metal loss/ corrosion</td>
<td>Direct</td>
</tr>
</tbody>
</table>

1) The techniques will require a conductive water phase. The probes may be affected by fouling, formation of a biofilm, hydrocarbon and other deposits.

2) Extent of hydrogen diffusion for systems containing H2S.
If the cathodic protection (CP) system should turn out not to meet the protection criterion or the installed capacity of the CP system are inadequate and unable to meet the pipeline design life (anodes have for some reason shown excessive depletion), it is possible to retrofit anodes by the installation of anode banks. It is necessary to do a reassessment of the cathodic protection system and to qualify the method for installation.

### Table C-3  Examples on monitoring parameters for product control and internal corrosion control

<table>
<thead>
<tr>
<th>Monitoring</th>
<th>Parameter</th>
<th>Dry gas (export/gas lift)</th>
<th>Wet gas</th>
<th>Multi-phase (production)</th>
<th>Crude oil (export)</th>
<th>Injection Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid composition</td>
<td>CO₂-content</td>
<td>×</td>
<td>×</td>
<td>×</td>
<td>(×)</td>
<td>(×)</td>
</tr>
<tr>
<td></td>
<td>H₂S-content</td>
<td>×</td>
<td>×</td>
<td>×</td>
<td>(×)</td>
<td>NA if SW</td>
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<tr>
<td></td>
<td>O₂-content</td>
<td>(×)</td>
<td></td>
<td></td>
<td></td>
<td>Online if SW??</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>× if PW??</td>
<td>(×) if PW</td>
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<tr>
<td></td>
<td>Water dew point</td>
<td>online</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td></td>
<td>H₂O-content</td>
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<tr>
<td></td>
<td>HC-dew point</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
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<td></td>
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<tr>
<td></td>
<td>Wax temperature</td>
<td>(×)</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Hydrate formation temperature</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
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<td></td>
<td>Other 1)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
</tr>
<tr>
<td>Sampling: Liquid / water /oil / solids</td>
<td>Sulphur containing compounds 2)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
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<td></td>
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<td></td>
<td>Conductivity</td>
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<td>(×)</td>
<td>(×)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cation/Anion content 3)</td>
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<td>(×)</td>
<td>(×)</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>pH (pH-buffering chemicals)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bacteria 4)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Rest inhibitor (e.g. scale/wax/corrosion)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Glycol – methanol content</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Scavengers</td>
<td></td>
<td></td>
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<td></td>
<td>Dispersants</td>
<td></td>
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<td></td>
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<td></td>
<td>Organic acids</td>
<td>(×)</td>
<td>(×)</td>
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<tr>
<td></td>
<td>Others 5)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
</tr>
</tbody>
</table>

1) E.g. nitrogen, hydrocarbons, suspended solids  
2) E.g. mercaptans, disulfide, sulfide, elemental sulphur  
3) E.g.: Fe²⁺, Ca²⁺, Mg²⁺, Na⁺, K⁺, Ba²⁺, Sr²⁺, SO₄²⁻, Cl⁻, HCO₃⁻  
4) Typical bacteria analysis of SRB, APB and/or GAB  
   SRB - sulphate reducing bacteria  
   APB - acid producing bacteria  
   GAB - general aerobic bacteria  
   Other types of bacteria may also be included e.g. in the case of nitrate treatment of injection water in order to reduce the activity and number of SRB  
5) E.g. suspended solids, viscosity, analysis of samples of debris after cleaning pigging, mercury, radioactivity (accumulation of natural occurring radioactive material in scale deposition in the pipeline)  
6) PW - Produced Water  
   SW - Sea Water  
   NA - not applicable  
7) Chemical for corrosion control of may contain some oxygen unless it is removed from the solution prior to injection

Online online monitoring - Required  
× Scheduled sampling - Required  
(×) Scheduled sampling - Recommended
### Table C-4 Process monitoring and internal corrosion control

<table>
<thead>
<tr>
<th>Process parameter</th>
<th>Parameter</th>
<th>Dry gas (export/gas lift)</th>
<th>Wet gas</th>
<th>Multi-phase (production)</th>
<th>Crude oil (export)</th>
<th>Injection Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational</td>
<td>Pressure</td>
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<td>online</td>
<td>online</td>
<td>online</td>
<td>online</td>
</tr>
<tr>
<td></td>
<td>Temperature</td>
<td>online</td>
<td>online</td>
<td>online</td>
<td>online</td>
<td>online</td>
</tr>
<tr>
<td></td>
<td>Flow rates (oil/gas)</td>
<td>online</td>
<td>online</td>
<td>online</td>
<td>online</td>
<td>online</td>
</tr>
<tr>
<td></td>
<td>Water cut</td>
<td>online</td>
<td>online</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chemical</td>
<td>Biocides</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
</tr>
<tr>
<td>injection</td>
<td>Inhibitors (e.g. scale/wax/corrosion)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Glycol - methanol</td>
<td>(×)</td>
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<td></td>
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<tr>
<td></td>
<td>pH-buffering chemicals</td>
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<td></td>
<td>Scavengers</td>
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<tr>
<td></td>
<td>Dispersants</td>
<td></td>
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<td></td>
<td>(×)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Others</td>
<td>1) (×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
<td>(×)</td>
</tr>
</tbody>
</table>

1) E.g. chemicals used for down periods or cleaning

Definitions

**Dry gas:** Natural gas that does not contain a significant content of moisture (water) and with a temperature above the gas water dew point at a given pressure. (Lean gas is also sometimes called dry gas- see below).

**Wet gas:** Natural gas that contains water or likely to contain liquid water during normal operation (sometimes also referred to as containing free water)

**Lean gas:** Natural gas that contains a few or no liquefiable liquid hydrocarbons. (Lean gas is also sometimes called dry gas)

**Rich gas:** Natural gas containing heavier hydrocarbons than a lean gas as liquid hydrocarbons

**Dew point:** The temperature at any given pressure at which liquid begins to condense from a gas or vapour phase. Water dew point – the temperature at which water vapour starts to condense

**Hydrocarbon dew point:** the temperature at which hydrocarbons starts to condense
APPENDIX D
LEAK DETECTION SYSTEMS

D.1 Introduction
This appendix provides a short overview of different technologies suitable as leak detection systems for subsea pipelines. Brief comments on whether the leak detection systems are suitable for onshore pipelines are given as well.

Subsea Leak Detection Technologies

D.2 Subsea leak detection technologies
Fig. D-1 below shows a schematic overview of different types of subsea leak detection technologies and applications.

Continuous Monitoring
- Permanently installed systems
- “Smoke-detectors”
- Reliability and life-time important

Inspection / surveying
- Sensors attached to mobile units
- ROV or AUV
- Pigs

Templates
- Point sensors
  - Various chemical methods
- Limited-range systems
  - Acoustics
  - Optical

Pipelines
- Internal systems
  - Mass/flow monitoring
  - Pressure drop
  - Real-time transient modeling
- External systems (along pipelines)
  - Vapor monitoring
  - Fiber-optic cables

Figure D-1
Schematic overview of different subsea leak detection approaches and corresponding technologies

There are two main different approaches to subsea leak detection in general; continuous monitoring and inspection/surveying:

- By continuous monitoring, the leak detection systems/sensors are permanently installed at the subsea structures, and function as a kind of “smoke-detector” which gives an alarm if a leakage occurs. The reliability and lifetime of such systems are therefore important.
- By inspection/surveying, the leak detection sensors are attached to mobile units such as ROVs, AUVs or pigs, and the subsea structures are inspected by these mobile units. Such inspection (by ROV) is usually very important during commissioning.

For continuous monitoring systems, the type of application is very decisive; as there is a major difference in the required functionalities of systems suited for monitoring of templates and pipelines, respectively. Leak detection systems such as point sensors and limited-range systems are well-suited for monitoring of templates, but these are not suitable for monitoring of pipelines, due to the long distances involved.

There are two main types of leak detection systems used for monitoring of subsea pipelines:

- internal systems, i.e. monitoring and modelling of flow parameters such as mass balance and pressure
- external systems, i.e. installing different types of sensor cables along the pipeline.

D.3 Continuous monitoring of subsea pipelines by internal systems
Software-based systems that monitor and model internal parameters such as mass balance, volume flow and pressure differences have been used for pipeline leak detection for several years. Such systems are still the only practical option for monitoring of long-distance pipelines, and can be used for both onshore and offshore pipelines.

There are several commercial software-based systems available, and they are mainly based upon one of the principles discussed below or a combination of these.

D.3.1 Mass/flow monitoring
By monitoring the flow parameters of a pipeline or pipeline section, a leakage may be detected if there is a discrepancy between the inflow and outflow. The leak rate can be estimated from the difference between the inflow and outflow, and the leak localization can be modelled.
External flow meters (clamp-on’s), such as ultrasonic flow meters, can be attached along the pipeline for accurate flow measurement. Although it has been reported that such flow meters have been installed at a subsea pipeline [4], this is perhaps more suitable for onshore pipelines.

D.3.2 Pressure drop

A pipeline leakage generates a pressure drop in the pipeline downstream of the leakage location. By monitoring and modelling the pressure conditions in the pipeline, leakages can be detected and localized.

Additionally, a suddenly occurring pipeline leakage or rupture generates an acoustic pressure wave inside the pipeline fluid. By detecting such a pressure wave, the leakage can be detected and localized.

D.3.3 Real-time transient modelling

Leak detection by real-time transient modelling is based upon complex algorithms and software models using advanced fluid mechanics and hydraulic modelling. The modelling is based upon various flow parameters measured under transient and dynamic conditions. Calculations of leak size and location are possible.

Such systems can be very sensitive regarding leak size and also very accurate in determining leak location.

D.4 Continuous monitoring of subsea pipelines by external systems

External leak detection systems are sensors that are installed along the pipeline. The major current limitation of such systems is to cover long distances. Currently there are two types of such technologies suitable for monitoring of subsea pipelines: vapour monitoring and fibre-optic cables.

D.4.1 Vapour monitoring

This system is a sensor tube that is placed parallel to the pipeline, as schematically shown in Fig. D-2 below. When a leakage occurs, vapour from the leaking fluid will diffuse into the sensor tube and is then transported to a measuring station. By analysing the concentration profile of the vapour, the leak location and leak size can be estimated.

Due to the necessary need for direct physical contact between the tube and the fluid, the pipeline is often buried. The system can be used at both onshore and offshore pipelines.

D.4.2 Fibre-optic cables

Although fibre-optics itself is not a new technology, the use of fibre-optic cables as leak detection systems along pipelines is currently an emerging and promising application of this technology. Fig. D-3 below shows a schematic illustration of the functioning principle of fibre-optic cables.

Pulses of laser light are sent into the cable, and are partially backscattered by the cable material throughout the cable. This backscattering process is influenced by the physical properties of the cable material, which is in turn dependent upon the ambient cable conditions such as temperature, pressure, strain and vibrations. Therefore, by analysing the characteristics of the backscattered light, information about the ambient conditions along the cable may be obtained. This information can be used to detect pipeline leakages:

— Temperature sensing: A leakage usually generates a large temperature difference in the immediate vicinity of the leakage location, and this temperature difference can be detected by a fibre-optic cable. Typically, fibre-optic cables can measure temperature differences of about 1 °C within 1-2 m sections of the cable, depending of the total distance covered.

— Acoustic sensing: The vibrations created by a leakage generate acoustic noise that can be recorded by the fibre-optic cable. Typically, the resolution is 10 m of cable, where each 10 m section in principle functions as an advanced microphone.

Fibre-optic cables can be used at both onshore and offshore pipelines.

D.5 Subsea leak detection by inspection/surveying

By attaching suitable sensors at mobile subsea vehicles such as ROVs and AUVs, both subsea templates and pipelines may be inspected for possible leakages. The purposes of such inspections may be:

— detection of possible leakages during commissioning
— periodic surveying of subsea structures
— exact localization of known leakages, which have previously been detected by other means.

There are several different types of sensors that may be attached to ROVs or AUVs and used for subsea leak detection:

— chemical methods, such as mass spectrometry and methane “sniffers”
— acoustic methods, such as hydrophones (passive acoustic) and sonar (active acoustic)
— optical methods, such as video cameras and fluorescence; the latter detects pre-injected fluorescent dye.

Periodic surveying of pipelines by ROVs or AUVs may actually border on continuous monitoring, depending upon the surveying frequency. The limitations for such an application might be the vehicle speed and the maximum distance.
Another possible approach to leak detection by pipeline inspection is to attach a leak detecting sensor on a pigging tool. Pipelines are often routinely inspected by pigs in order to assess the pipeline integrity and detect possible corrosion. Leakages can also be detected in this manner by attaching suitable sensors, such as an acoustic device, to the pig.

An advantage of the pig approach is that long pipeline distances can be covered, and both the onshore and offshore parts of the pipeline can be inspected. However, as for ROV and AUV surveying, the frequency of the pigging is crucial.

**D.6 Selection criteria for subsea leak detection systems**

Besides cost, there are several important criteria to consider when selecting a leak detection system for a given subsea pipeline:

- Distance, i.e. pipeline length
- Sensitivity (detection of small leakages)
- Response time or inspection frequency
- Reliability (no false alarms)
- Accurate localization of leakage
- Lifetime and maintenance needs (for external systems)
- Type of pipeline and production/flow assurance issues.

**D.7 Authority requirements**

In the Norwegian sector, all subsea installations (including pipelines) should be equipped with systems that monitor its integrity, which means that suitable leak detection systems need to be installed. The current requirement is that the best available technology (BAT) should be used, a requirement that is based upon EU’s IPPC-directive.

A similar requirement is also currently present in the US.
APPENDIX E

INSPECTION AND MONITORING TECHNIQUES

E.1 Pipeline inspection methods

The various inspection (survey) methods for either external inspection or in-line inspection are briefly described below.

E.1.1 EXTERNAL (SUBSEA) INSPECTIONS

E.1.1.1 External carriers

There are different options for external carriers of survey equipment. The choice of inspection vehicle may be subject to the threats related to the individual pipeline. The different vehicles will have different capacity with respect to speed, ability to carry sensors and data accuracy and therefore have got different advantages for consideration.

**ROV** - Remotely Operated Vehicles (ROV) are used for inspection of submarine pipeline system and lower parts of the splash zone. The ROV either runs on support wheels on top of a pipeline or moves above the pipeline system. The ROV can be equipped with various equipment depending on the inspection and monitoring requirements, as typically:

- visual control (video or still camera)
- sonar systems (Multi Beam (MB) sonar or Side Scan Sonar)
- positioning systems and mapping of pipeline position relative to sea bottom (transponders, digiquarts measurements, photogrammetry etc)
- seabed mapping
- pipeline location and burial depth measuring (pipe tracker including cross profiler, video and inclinometer)
- measurement of corrosion protection system (stab- and/or field gradient-measurements)
- environmental sensors (measuring parameters that influence the sound velocity in water)
- manipulator arms.

The ROV is normally regarded as a relatively slow, but reliable, survey platform. The speed of the survey is a compromise between ROV capacity, data density, water depth and environmental conditions. In good conditions, a survey speed between 1.0 and 1.5 m/s can be achieved. In other areas a survey speed of less than 0.5 m/s can be expected.

The use of ROV can in any case provide good positioning data, combination of all available survey tools and the possibility to stop and provide extra details when required. The sub-surface positioning may typically be provided with an absolute accuracy of 0.5 metres dependant on water depths. The favourable manoeuvrability of an ROV will provide possibility for simultaneous utilisation of boom cameras, pipe trackers and multi-beam echo sounders.

As of today the ROV is the only alternative to carry the wide range of survey tools simultaneously and for close visual inspection of pipelines. The ROV will therefore be the best method for detecting most of the individual threats.

The achieved quality by the ROV system is to a high degree degraded by poor visibility caused by muddy water, schools of fish etc. and the quality of the ROV survey may also be affected by strong current.

**ROT** - The Remotely Operated Towed Vehicle (ROT) is used for external inspection of the pipeline system. The system has no internal powered progress in any direction, but can be steered sideways and up/down by rudders to provide a best possible position and altitude relative to the pipeline. The ROTV is towed behind a survey vessel at relatively high speeds, typically 4 knots (equals to 2 m/s). The normal operation will be to position the ROTV beside the pipeline (typically 20 metres), at an altitude of 10–20 metres.

Traditionally the ROTV has only been capable of carrying a Side Scan Sonar, but new technology has also allowed the inclusion of a multi-beam echo sounder. Future technology development may include pipe trackers for use on ROTV under certain conditions.

Compared to an ROV, the ROTV is faster and has a longer range, but can only carry limited sensors and will for certain have lower potential for observing certain threats. The ROTV will however provide sufficient results with respect to detecting most third party threats and may also provide a fair representation of the pipeline laying conditions including freespan detection. The layback between the vessel and the ROTV is relative to the water depth and therefore the quality of the positioning of the ROTV subject to the water depth. The ROTV cannot stop and perform detailed survey of a particular area.

The ROTV can be evaluated as a primary tool for pipeline inspection in certain areas, but can also be evaluated as a tool for providing the “big picture” prior to a more detailed survey performed by a ROV at limited areas of interest.

The method is however restricted by the water depth and is not recommended for depths larger than approximately 300 m.

**Tow-Fish** - The tow-fish is as the ROTV towed after the survey vessel, but with no means of active steering of the vehicle. The tow-fish position is controlled by tow-cable and vessel speed. In practical terms, the tow-fish does only have the capability to carry Side Scan Sonars.

**Un-tethered underwater vehicle** - Un-tethered underwater vehicle (UUV) is a free-swimming vehicle that can be programmed to run by a pre-defined program, but can also be given commands by acoustic links. A typical vehicle is Hugin, manufactured by Kongsberg, operated at a speed of typically 4 knots. The vehicle is launched and retrieved from a vessel, and needs the vessel to follow under a mission. Sample data can be transmitted to the vessel by an acoustic link during the mission for quality checks. Survey tools can be multibeam bathymetry, sidescan sonar and sub bottom profiler. The UUV can not stop and perform detailed surveys.

**Autonomous underwater vehicle** - Autonomous underwater vehicle (AUV) is a robot without a fixed cable to a survey vessel and does not have any remote control capabilities. It is launched and retrieved from a vessel and follows a pre-defined route. Survey tools can be multibeam bathymetry, sidescan sonar and sub bottom profiler. The AUV can not stop and perform detailed surveys.

**Divers** - Divers can be required if the operation can not be performed by ROV and if the depth is not more than approximately 150 m.

E.1.1.2 External inspection tools

**Visual / Video / photo** - An ROV is usually equipped with several cameras, which are used for visual inspections of the pipeline system.

Normally, three cameras will be utilised for visual pipeline inspection, namely one top camera and boom cameras either side. It is important to maintain the cameras at the same relative position and to maintain the boom cameras in a position relative to the pipeline to provide best possible coverage of the pipeline and the surrounding seabed. Furthermore it is important to optimise the lighting of the ROV to provide the best possible picture quality during the inspection.

Both General Visual Inspection (GVI) and Closed Visual Inspection (CVI) can be performed.

Visual inspections are recorded digitally for documentation. Visual inspections offer easy identification of visible observa-
tions of the system and the seabed for manual interpretation by the operators.

Close Visual Inspection is the best available method for detecting all threats and for providing the best understanding of the pipeline laying conditions including freespan configuration. However, it is important to be aware of the reduction in quality of recorded data in areas with poor visibility.

**Sidescan SONAR** - The sidescan sonar (SOund NAVigation Ranging) is able to look sideways.

The sidescan sonar creates an image of the seabed and pipeline by transmitting sound waves towards the seabed and analysing the echo. It creates images of the seabed even in water with reduced visibility. It can provide high resolution images and it can detect objects from significant distances. Survey images are manually interpreted.

For visual surveys the Side Scan Sonar is very often providing complementary information as it has the potential for a wide detection of large observations such as large 3rd party damages, intervention, shifting seabed conditions etc.

Used as a primary inspection tool, Side Scan Sonar will be able to identify large 3rd party damages as well as the pipeline burial status and also freespanning activity although to a lower accuracy than during visual surveys.

**Multibeam Echosounder (MBE)** - This sonar based technology is used to map the seabed topography in the vicinity of the pipeline including the pipeline position relative to the seabed. The tool transmits sound waves towards the seabed and makes a profile of the seabed and pipeline. It enables high resolution screening and detects objects and installations in the vicinity of the pipeline, and is very useful for imaging the pipeline and surrounding seabed for freespan detecting. A very high data density may be achieved from MBE systems, only limited by the detected range of the system. Therefore the data density has no practical impact on the speed of the surveys. The system operates at high frequency with no means of detecting buried objects.

**Cross profiler** - In principle, this is the same concept as the Multibeam sonar, but the technology is older, it is a more time consuming method and it holds only one sonar. It consists of moving scanning heads providing a cross profile over a few seconds of time introducing errors as the vehicle is moving forwards.

A cross profiler records the seabed in a cross-section (2D) at the actual position. A cross profiler delivers typically listings of seabed elevation and the top-of-pipe for unburied pipelines. For buried pipelines, the burial depth can be found if combined with a pipetracker.

**Pipetracker** - The pipetracker is used to detect and survey buried pipelines down to approximately two meters below the seabed. There are different technologies on the market, both acoustic low frequency sensors and electromagnetic systems. The latter technology is mostly used in the industry at present. The tool uses a magnetic field to measure a relative distance between the tool and pipeline. The tool should be calibrated to the specific pipeline and its target burial depth. Survey errors are dependent on the tool itself and the operation of the carrier (ROV), however, small diameter pipelines with large burial depth are difficult to detect. The pipetracker can only detect the lateral and vertical distance from the sensor to the top of the pipeline and the data needs to be merged with complementary data measuring the distance between the sensor and the seabed to provide burial depth.

The pipetracker can not measure the seabed profile.

**Sub bottom profiler** - This is an acoustic based tool operating at low frequency penetrating the seabed to provide burial depth. It is also a profiling tool for shallow geophysics. The tool has limitations with regard to measuring the configuration of the pipeline and can only be used to track the pipeline if used at high altitude from a vehicle crossing the pipeline to spot check burial depth at certain points (as opposed to running along the pipeline). There are technology development projects ongoing that may provide large improvements and possibilities for the future.

**Stabbing** - 1) Stabbing consists of physically penetrating a pole through the soil to measure the pipeline cover-height. It is often used for calibrating other tools. Stabbing is normally used for short sections.

**Stabbing** - 2) Recordings of anode potentials and pipe protection potentials is sometimes carried out by contacting the anode or pipe surface by some spike arrangement connected to a reference electrode via a voltmeter. Such potential recordings are often referred to as “stabblings”. The recordings are applicable to demonstrate that anodes are “active”, i.e. that the anode potential is not less negative than the design value, and that the protection potential is more negative than the design protective potential.

**Eddy Current** - This is an electrical NDT method which can be utilised to detect and quantify surface breaking or near surface defects in the pipe material. It is a non-contact method and can test through paint coatings.

It can not size cracks larger than approximately 2 mm.

**External UT** - External UT (Ultrasonic Testing) tools are available for both onshore (in atmospheric) conditions and for offshore (ROV or divers) applications. The UT tools spans from the single handhold probe to fully automated UT tools (AUT) that scans a section of the pipe and store the measurements in a data logger.

**E.1.1.3 Onshore inspection tools**

**CP-measurements** - On onshore pipelines, periodic recordings of the pipe-to-soil potential is carried out at test posts located along the line, mostly with a permanently installed reference electrode close to the pipe surface. Potential recordings may be carried out manually at the test posts, or recordings may be carried out automatically for electronic transfer to a remote location. As an alternative to a close fixed reference electrode, a portable reference electrode may be positioned at the surface close to the test post. The potential recording will then include an IR-drop which in some cases represents a significant measuring error. The IR-drop can, however, be eliminated by so-called on/off measurements for which the DC-source for CP is interrupted for a short period of time and the instantaneous potential drop (i.e. the actual IR-drop) is recorded. Periodic CP surveys should also include testing of the efficiency of electrically insulating joints.

Special onshore CP surveys are carried out for the purpose of e.g. detecting and locating coating defects (CIPS or “close interval potential surveys”) or to detect interaction between the pipeline CP-system and other buried structures, with and without an own CP system. The objective can further be to detect stray currents in the ground originating from other remote DC sources. As such sources are not normally permanent, recordings of DC-interference have to be carried out by continuous monitoring of pipe-to-soil over an extended period of time.

Special CP onshore surveys will have to be carried out by personnel with documented training and practical experience of such surveys. EN 13509 describes various techniques to monitor buried and immersed CP systems, including the testing of pipeline insulating joints.

Further more description of onshore inspection tools and methods, reference is given to ASME B31.8S and API1160.

**E.1.2 In-Line Inspection (ILI) with Intelligent Pig**

**Magnetic Flux Leakage** - A MFL-pig measures changes in wall thickness from the inside of a pipeline made of a ferromagnetic material. It can operate in both gas and liquid fluids.
The method detects metal losses caused by e.g. pitting or generalised corrosion. An MFL pig detects the change in magnetic response from the pipe in connection with metal loss. The MFL technology is an indirect method to size defects since the signals is a function of the volume of the corrosion defect. The signals have to be subsequently analysed in order to determine the dimensions of the defect.

The MFL inspection pig can detect both external and internal metal loss defects. MFL pigs are available in HR (high resolution) and XHR (extra high resolution) versions. The sizing accuracy of the defect depth for the XHR version is of the order of 5%-8% of the wall thickness for a wall thickness of about 1" (25.4 mm) and internal defects. This corresponds to an accuracy of 1.3 mm to 2.0 mm. For external defects or thicker wall thickness the accuracy reduces.

**Ultrasound Technology** - Ultrasound Technology (UT) is used as a pigging tool to measure the absolute thickness of the wall. The technique can differentiate between external and internal metal loss. It can only operate with a liquid film between the sensors and the wall and is therefore mostly used in pipelines transporting fluids. In case of gas pipelines, the pig has to be carried in a liquid plug. The UT-pig requires that the steel surface has been properly cleaned in order to obtain reliable measurements. The method is also restricted by the wall thickness and the speed. An UT-pig can be run for all types of pipeline materials (i.e. both ferrous and non-ferrous). The method also detects cracks.

**Optical inspection tool** - The laser-optic instrument records a visual image of the inner wall of pipelines carrying transparent fluids. Features are visualised giving valuable information for evaluating and interpretations of the features. The image can be processed and animated adding a 3D grid and the feature can be positioned and sized, for defects the clock and KP-position, width, length and depth can be provided. The optical inspection tool is hence considered to represent a new and valuable inspection tool for inspection of internal features in pipelines carrying transparent fluids, e.g. gas pipelines. The sizing accuracy would be of the order of 0.5 mm for the depth and provides the profile of the defects. Dropouts of oil and debris may fill potential pits reducing the value of the visual image and the accuracy of the seizing of the defects.

**Geopig** - Geopig is a pig that measures the global curvature based upon gyro-technology. A geopig can measure the global curvature with a high accuracy. The distance is measured by a method also detects cracks.

**Calliper** - A calliper pig measures the pipe out-of-roundness. Simple calliper tools indicate pipeline damage (e.g. a dent, a buckle) without giving information regarding its location.
# Example of a Risk Assessment Scheme

<table>
<thead>
<tr>
<th>Threat Group</th>
<th>Threat</th>
<th>Potential Initiator</th>
<th>Pipeline Sections</th>
<th>Protective means (DFI)</th>
<th>Acceptance Criteria</th>
<th>PoF Category</th>
<th>CoF Category</th>
<th>Risk Category</th>
<th>Additional protective means</th>
<th>IMT Activities</th>
<th>IMT Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>DFI</td>
<td>Design errors</td>
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<td>Significant temperature variations</td>
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<td>Incorrect</td>
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<td>Interface component related</td>
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</tbody>
</table>

### Figure F-1
Example of a risk assessment scheme
APPENDIX G
EXAMPLE - RISK ASSESSMENT AND IM PLANNING

G.1 System description and background
System description is as follows - see Fig. G-1
— 10" Oil Flowline design temperature: 140 °C
— design pressure: 200 bar
— production start-up: 2004 (from 2 out-of 4 wells)
— 4 wells from 2006. Plateau in 2009
— the pipeline is designed to buckle at two locations (A at start-up; and B after full production) outside the safety zone.

From the design documentation, the relative utilisation of the two buckles at design condition is 0.93 and 0.87 for location A and B, respectively.

G.2 Risk assessment
PoF modelling
The pipeline has been designed in accordance with DNV-OS-F101 and the expansion design has been done according DNV-RP-F110 - Global buckling.
A simple rule describing the relation between utilisation according to DNV-OS-F101 and probability category has been established (for illustration only). This rule is described in Table G-1.

Applying the rule together with the reported utilisation from the design documentation yields in a PoF-category 3.

CoF modelling
The consequence of failure is determined using the 'Product model' as described in Table 4-4. The product together with the diameter yields a consequence category C, see Table G-2.

Risk level
Combining the PoF (3) and the CoF (C) into the risk matrix yields a “Medium Risk” level.
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### G3 Inspection interval

A work selection matrix is used to determine the base inspection interval ($I_R$).

The final inspection interval is determined as:

$$I = I_R \cdot C \cdot D$$

where $C$ and $D$ are adjustments factors for confidence in and possible development of PoF.

The confidence factor reflects the uncertainties in the PoF category. In this case, the PoF is determined only based on design calculation and the confidence is low until the expansion design has been verified through external inspection. A simple rule is outlined in Table G-3.

Similarly, Table G-4 gives a rule for determining the development factor ($D$).

### Table G-3  Confidence factor

<table>
<thead>
<tr>
<th>Condition</th>
<th>Confidence factor (C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start-up of production</td>
<td>0.5</td>
</tr>
<tr>
<td>Good agreement between design</td>
<td>1.0</td>
</tr>
<tr>
<td>and observations</td>
<td></td>
</tr>
</tbody>
</table>

### Table G-4  Development factor

<table>
<thead>
<tr>
<th>Condition</th>
<th>Development factor (D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>More buckles are expected</td>
<td>0.5</td>
</tr>
<tr>
<td>A fully expanded configuration is achieved</td>
<td>1.0</td>
</tr>
</tbody>
</table>

### Initial inspection

The initial inspection is derived from work selection matrix and quantification of $C$ and $D$, see next table. According to the procedure, the first inspection should be done during the first year of operation. This is also in compliance with the requirements to start-up inspection in DNV-OS-F101.

### Table G-5  Condition

<table>
<thead>
<tr>
<th>Condition</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inspection interval based on Risk ($I_R$)</td>
<td>3 years</td>
</tr>
<tr>
<td>Confidence factor (start-up of production) ($C$)</td>
<td>0.5</td>
</tr>
<tr>
<td>Development factor (More buckles are expected) ($D$)</td>
<td>0.5</td>
</tr>
</tbody>
</table>

### Table G-6  Simple example illustrating a risk assessment for determining inspection timing

<table>
<thead>
<tr>
<th>Inspection #</th>
<th>$I_R$</th>
<th>$C$</th>
<th>$D$</th>
<th>$I$</th>
<th>$I^*$</th>
<th>I-Year</th>
<th>I-Type</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st</td>
<td>3</td>
<td>0.5</td>
<td>0.5</td>
<td>0.75</td>
<td>1</td>
<td>2005</td>
<td>ROV</td>
<td>Start-up inspection, see DNV-OS-F101 Sec.11 D302</td>
</tr>
<tr>
<td>2nd</td>
<td>3</td>
<td>1.0</td>
<td>0.5</td>
<td>1.5</td>
<td>2</td>
<td>2007</td>
<td>ROV</td>
<td>One buckle (location A) has developed and the result in terms of utilisation is consistent with predictions done in the design, hence the confidence factor has been increased to 1.0. The buckle at location B is expected to develop when production from well 3 and 4 is started in 2006. The inspection should be done after the production from all wells have started, i.e. 2007.</td>
</tr>
<tr>
<td>3rd</td>
<td>3</td>
<td>1.0</td>
<td>1.0</td>
<td>3.0</td>
<td>3</td>
<td>2010</td>
<td>ROV</td>
<td>All buckles have developed and the inspection results compare very well with the design predictions. Both the confidence factor and the development factor are set to 1.0.</td>
</tr>
<tr>
<td>4th</td>
<td>5</td>
<td>1.0</td>
<td>1.0</td>
<td>5.0</td>
<td>5</td>
<td>2015</td>
<td>Sonar</td>
<td>Maximum production was reached in 2009 and the production is currently decreasing. The utilisation of the buckles is below 0.75 (PoF category is 2).</td>
</tr>
</tbody>
</table>
APPENDIX H
RISK ASSESSMENT - WORKING PROCESS

H.1 Risk assessment - a working process description

The risk assessment comprises the following main tasks, see also Fig. H-1:

a) Establish equipment scope
b) Identify threats
c) Data gathering
d) Data quality review
e) Estimate probability of failure (PoF)
f) Estimate consequences of failure (CoF)
g) Determine risk
h) Identify risk mitigating measures
i) All equipment threats have considered
j) Determine aggregated risk
k) Planning of inspection, monitoring and testing activities

(Ref. Sec.4.4)

a) Establish equipment scope
Risk assessment shall be conducted for the pipeline system. The pipeline as well as all components where a failure jeopardises the structural integrity of the pipeline system shall be included.
b) Identify threats
A general overview of submarine pipeline threats is presented in Table 3-1.
Identification of threats should be done in workshops with participation form all relevant disciplines. It is also important to involve resources with background from both design and operation; people with in-depth knowledge of the system in question. These working sessions should be structured and planned, and the outcome should be properly documented.

Typical sources for identification of threats are:
— previous risk assessments (both done in the design phase and in the operational phase)
— design documentation, hereunder but not limited to DFI-documents
— results and documentation from the other Integrity Management Process activities, e.g. pipeline inspection reports
— operator’s and industry experience, e.g. failure statistics.

The output of the threat identification activities is a list of relevant threats and notes with regard to e.g. failure modes, loads and causes, location, as well as related issues of uncertainty.

It is recommended to develop appropriate and re-usable forms for carrying out and recording results and notes from the reviews and any research processes.
c) Data gathering
The data needed to perform the risk assessment varies from threat to threat and is also dependent on the adopted risk approach. The data sources shall be documented.
d) Data quality review
The quality of data shall be reviewed and in case of missing or large uncertainties in the data, conservative assumptions shall be made. Alternatively, more accurate data need to be gathered, e.g. through additional inspections, monitoring and testing.

The uncertainties in the data shall be documented as this is important input for selecting the correct or most cost effective mitigating action.

e) Estimate probability of failure
The estimation of probability of failure shall follow a documented procedure. Deviation from the procedure should be documented and justified.

All threats shall be considered either as individual threats or on a group level. Components of equal type can be evaluated together.

Depending on the adopted methodology, the pipeline can be divided into sections. The selection of input data shall reflect a conservative approach for the entire section.

An alternative to pipeline sectioning is to describe the input parameters as profiles along the route and use a rule to estimate the PoF-profile.

If the consequence modelling is done on a failure mode level, e.g. leak, burst; the PoF modelling needs to consider all relevant failure modes.
f) Estimate consequence of failure
The consequence of failure can be modelled at:
— threat group level, in this case the worst consequence related to the grouped threats apply
— individual threat level, in this case the worst consequence related possible failure modes apply
— failure mode, in this case the consequence profile can be used for all threats which may yield such failure mode.

g) Determine Risk
The risk is the product of PoF × CoF. In case the risk is not acceptable, mitigating measures need to be evaluated.
h) Identification of risk mitigating measures
To be able to select cost effective mitigation, it is important to identify the risk driving factors. In this context, the results from step d) “Data quality review” may provide valuable information.

Further, selection of the most cost effective measure may only be done after all threats have been considered. Risk reduction can either be achieved by reducing the probability or the consequence (or both) of an event.

Typical mitigating measures to reduce the probability side are:
— analytical, i.e. more refined calculations
— additional inspection, monitoring and testing
— intervention or repair
— de-rating e.g. load reduction
— load control measures
— replacement.

Among the measures to reduce the consequence side are:
— analytical, i.e. more refined calculations
— enhance emergency response procedures and associated equipment (especially related to safety and environmental consequences)
— enhance pipeline repair strategies and equipment to reduce down time (economical consequences)
— establish optional solutions to take over the functionality of the failed equipment.

i) All equipment threats considered
Check point to ensure that the risk assessment has been completed.

j) Aggregated risk
In case a quantitative risk assessment has been done, a total
risk profile can be generated along the pipeline system sum-
mring up the contribution from all threats. To get an overall cor-
rect risk level, all relevant failure modes needs to addressed.
The above is less feasible if a qualitative risk assessment has
been undertaken where the risk is expressed in qualitative
terms, e.g. Low, Medium High (unless these terms are associ-
ated with a value or if a scoring/index system has been
applied).

The risk profile should be benchmarked towards risk profiles
for similar/comparable pipeline systems. This is done to ensure
consistency in the risk assessment and to detect gross errors.
An overall evaluation of the pipeline system should be made.
All identified mitigations shall be highlighted and registered in
an appropriate administrative system.

\textit{k) IM planning (Ref. Sec.3.4)}

The long term inspection plan should be based on the results
from the risk assessment. The following threat groups are nor-
mally considered in the long term planning:

\begin{itemize}
\item corrosion/erosion
\item third party
\item structural.
\end{itemize}

\textbf{Guidance note:}

With reference to Table 3-1, failure related to DFI threats nor-
mally occurs during installation and early operation. Inspections
related to natural hazard are generally done after an event, e.g.
after extreme weather. Incorrect operation can be detected by
scheduled inspections, but is normally covered by review/audits
and training of personnel.

\textit{---e-n-d---o-f---G-u-i-d-a-n-c-e---n-o-t-e---}

The pipeline system may be divided into sections dependent on
inspection types. This sectioning may reflect:

\begin{itemize}
\item the inspection type capabilities
\item manageable length within a year
\item historical practice
\item risk level (to focus the inspection on high risk sections).
\end{itemize}

Note that locations with unacceptable high risk may need
ad-hoc inspections which are not part of the long term plan.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{risk_assessment_diagram}
\caption{Risk assessment - working process}
\end{figure}