RECOMMENDED PRACTICE

DNV-RP-G101

Edition January 2021
Amended September 2021

Risk-based inspection of offshore topsides static mechanical equipment

DNV AS

FOREWORD

DNV recommended practices contain sound engineering practice and guidance.

Any comments may be sent by e-mail to *rules@dnv.com*

CHANGES – CURRENT

This document supersedes the July 2017 edition of DNVGL-RP-G101.
The numbering and/or title of items containing changes is highlighted in red.

Amendments September 2021

Topic	Reference	Description
Rebranding to DNV	All	This document has been revised due to the rebranding of DNV GL to DNV. The following have been updated: the company name, material and certificate designations, and references to other documents in the DNV portfolio. Some of the documents referred to may not yet have been rebranded. If so, please see the relevant DNV GL document. No technical content has been changed.

Changes January 2021

Topic	Reference	Description
New and revised introduction, objective and scope	[1.1], [1.2] and [1.3]	Included new and revised introduction, objective and scope subsections.
New methodology for evaluation of coating	[5.6.2]	Included new description of evaluation method for coating condition and degradation.
New methodology for corrosion under insulation (CUI)	[5.6.3] and [5.8.1.2]	Included new description of CUI risk management and reference to DNV-RP-G109.
New methodology for CUI and evaluation of effect of coating on stainless steel	[5.6.3] and [5.9.1.2]	Included new description of CUI risk management and reference to DNV-RP-G109, removed list point with methodology for PoF reduction due to coating efficiency.
New methodology for evaluation of MIC	[5.8.2.3] and App.B	Updated MIC model description and added new appendix for probability of failure evaluation of MIC.
Elemental sulphur in inert gas purged systems	[5.8.2.6]	Degradation mechanism elemental sulphur in inert gas purged system included and desbribed. Also other systems where elemental sulphur could be present is mentioned.
External stress corrosion cracking (ESCC)	[5.9.1.3]	Revised guideline to reflect that ESCC is relevant for both insulated and uninsulated stainless steel.
Document restructured	Sec.5	Appendix A moved to main document Sec.5.
	Sec.6	Appendix B moved to main document Sec.6.
	Sec.7	Appendix C moved to main document Sec.7.
	[1.5] and Sec.8	Appendix G replaced with main document section [1.4] *Reference* and Sec.8 *Bibliography*.
	App.A	Appendix E moved to App.A.
	App.C	Appendix B moved to App.C.

Topic	Reference	Description
	App.D	Appendix F moved to App.D.

Editorial corrections

In addition to the above stated changes, editorial corrections may have been made.

Acknowledgements

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SECTION 1 GENERAL

1.1 Introduction

The primary function of offshore static mechanical equipment is to prevent loss of containment. Managing the integrity of the static mechanical equipment is a complex and time-consuming activity representing a major cost in offshore oil and gas operation.

Risk-based inspection (RBI) is a systematic approach to assess probability of failure (POF), consequence of failure (COF) and consequently the risk related to loss of containment.

The purpose of RBI is to:

— identify high risk items with respect to personnel safety, economy and environment, due to leakage and burst.
— identify the degradation mechanisms that will give guidance in the choice of inspection- method and extent.
— identify time to inspection with respect to risk acceptance criteria.

This RP is developed to describe and give guidance on how to perform a RBI assessment on offshore static mechanical equipment.

The recommended practice is divided into two parts covering

1) an introduction to RBI
2) recommendations for a working process.

1.2 Objective

The objective of this recommended practice is to provide one common approach for risk-based inspection analysis of offshore topsides static mechanical equipment through risk management of loss of containment threats.

1.3 Scope

This RP describes a method for establishing and maintaining a risk-based inspection plan for offshore pressure systems. It provides guidelines and recommendations on how to customise methods and working procedures that support the inspection planning process. .

This RP covers the planning of in-service inspection for offshore topsides static mechanical pressure systems when considering failures by loss of containment of the pressure envelope. Failure modes and functional failures, such as failure to operate on demand, leakage through gaskets, flanged connections, valve stem packing, together with valve passing and tube clogging are not addressed in this document.

1.4 Application

This recommended practice applies to upstream offshore pressure systems, care should be taken if used on onshore assets. The document applies to pressure systems located between christmas tree wing valve and the export pipelines topsides emergency shut down (ESD) valve.

The RP applies to the following types of components:

— piping systems comprising straight pipe, bends, elbows, tees, fittings, reducers
— pressure vessels and atmospheric tanks
— pig launchers and receivers
— heat exchangers
— unfired reboilers
— valves

— pump casings
— compressor casings.

The RP does not apply to the following types of components:

— structural items including supports, skirts and saddles
— seals, gaskets, flanged connections
— internal components and fittings
— pressure containing instruments.

1.5 References

In the context of this document, the term standard shall be understood to cover document types such as codes, guidelines and recommended practices in addition to bona fide standards.

The latest valid edition of each of the DNV reference documents applies. For DNV reference documents, see Table 1-1. For other standards and recommended practices, the edition valid at the time of publishing this document applies, unless dated references are given. For external reference documents, see Table 1-2

Table 1-1 DNV references

Document code	*Title*
DNV-RP-B401	Cathodic protection design
DNV-RP-C203	Fatigue design of offshore steel structures
DNV-RP-F101	Corroded pipelines
DNV-RP-G109	Risk-based management of corrosion under insulation
DNV-RP-O501	Managing sand production and erosion

Table 1-2 Other references

Document code	*Title*
API 510	Pressure Vessel Inspection Code; In-Service Inspection, Rating, Repair, and Alteration
API 574	Inspection Practices for Piping System Components
API 579-1/ASME FFS-1	Fitness-For-Service
API RP 580	Risk-Based Inspection
API RP 581	Risk-Based Inspection Methodology
ASME B31.3	Process piping
ASME B31G	Manual for Determining the Remaining Strength of Corroded Pipelines
ASME BPVC VIII Div. 3	Boiler and Pressure Vessel Code - Section VIII: Rules for Construction of Pressure Vessels - Division 3: Alternative Rules for Construction of High Pressure Vessels
BS PD 5500	Specification for unfired fusion welded pressure vessels
EFC 16	Guidelines on materials requirements for carbon and low alloy steels for H_2S-containing environments in oil and gas production
EFC 17	Corrosion Resistant Alloys for Oil and Gas Production: Guidance on General Requirements and Test Methods for H_2S Service

Document code	*Title*
EFC 55	Corrosion-Under-Insulation (CUI) guidelines
HOIS-RP-103	HOIS Recommended Practice for Non-Intrusive Inspection of Pressure Vessels
ISO 12944-5	Paints and varnishes - Corrosion protection of steel structures by protective paint systems - Part 5: Protective paint systems
ISO 17776	Petroleum and natural gas industries — Offshore production installations — Major Accident hazard management during the design of new installations
ISO 21457	Petroleum, petrochemical and natural gas industries - Materials selection and corrosion control for oil and gas production systems
ISO 9000	Quality management systems - Fundamentals and vocabulary
ISO 9712	Non-destructive testing - Qualification and certification of NDT personnel
NACE MR0103/ISO 17945	Petroleum, petrochemical and natural gas industries - Metallic materials resistant to sulfide stress cracking in corrosive petroleum refining environments
NACE MR0175/ISO 15156	Petroleum, petrochemical and natural gas industries - materials for use in H2S containing environments in oil and gas product - Part 3
NACE 3T199	Techniques for Monitoring Corrosion and Related Parameters in Field Applications
NACE 31205	Application and Evaluation of Biocides in the Oil and Gas Industry
NACE SP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems
NACE SP0499	Standard Practice Corrosion Control and Monitoring in Seawater Injection Systems
NACE SP0775	Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations
NACE TM0106	Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion on External Surfaces of Buried Pipelines
NACE TM0194	Field Monitoring of Bacterial Growth in Oil and Gas Systems
NACE TM0212	Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion on Internal Surfaces of Pipelines
NORSOK M-501	Surface preparation and protective coating
NORSOK M-506	CO2 corrosion rate calculation model

1.6 Definitions and abbreviations

1.6.1 Definition of verbal forms

The verbal forms in Table 1-3 are used in this document.

Table 1-3 Definition of verbal forms

Term	*Definition*
shall	verbal form used to indicate requirements strictly to be followed in order to conform to the document
should	verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others
may	verbal form used to indicate a course of action permissible within the limits of the document

1.6.2 Definition of terms

The terms defined in Table 1-4 are used in this document.

Table 1-4 Definition of terms

Term	*Definition*
component	individual part that is used in constructing a piping system or item of equipment, such as a nozzle, flange, elbow, straight piece of pipe, tube, shell, head/end cap
condition monitoring	monitoring of physical plant conditions which may indicate the operation of given degradation mechanisms
coefficient of variation	spread of a distribution calculated as the standard deviation of a distribution divided by the mean value of that distribution
consequence of failure	outcome of a failure
consequence of failure ranking	qualitative statement of the consequence of failure often expressed as a textual description (high, medium, low) or numerical rank (1, 2, 3)
consequence of failure type	description of consequences of failure expressed as safety, environment or economic consequence
corrosion group/circuit	group/circuit of components that have the same potential degradation mechanisms because they are exposed to the same internal and external environment and made of the same material
damage type	physical discontinuity in the object or material as a result of a degradation mechanism
damage model	mathematical or heuristic representation of a degradation mechanism that expresses the damage rate
damage rate	development of damage over time
degradation	reduction of a component's ability to carry out its function
degradation mechanism	means by which a component degrades
economic risk	occurrence and outcome of a failure given in financial terms, expressed as the cost of production deferral per year
environmental risk	occurrence and outcome of a failure given in terms relevant to environmental damage, expressed as volume per year or currency per year
equipment	item having a process function on offshore topsides such as pressure vessels, heat exchangers, pumps, valves and filters

Term	*Definition*
failure	point at which a component ceases to fulfil its function and prescribed , implying loss of containment
failure mechanism	means by which a component fails due to the progression of damage
failure mode	manner in which failure can occur
fatal accident rate	potential loss of life per 100 000 000 hours
hot spot	location on a pipe or equipment where the degradation mechanism is expected to be most severe
inspection	activity carried out periodically to assess the progression of damage in a component
inspection effectiveness	ability of the inspection method to detect the damage type
inspection methods	means by which inspection is carried out, such as visual, ultrasonic, radiographic
inspection program	overview of inspection activity for several years into the future
inspection plan	details of a planned inspection activity giving the precise location, type and timing of each individual inspection task
inspection techniques	details of inspection method concerning surface and equipment preparation, execution, and area of coverage
limit state	mathematical description where the loss of pressure containment is calculated considering the magnitude of the applied load in relation to the ability to resist that load
limit state design	specific design check to ensure that failure does not occur and identifies the different failure modes
monitoring	activity carried out over time whereby the amount of damage is not directly measured but is inferred by measurement of factors that affect that damage
microbiologically influenced corrosion	corrosion affected by the presence and/or activity of microorganisms in biofilms on the surface of the corroding material, NACE TM0212
non-destructive testing	inspection of components using equipment to reveal defects without destroying the component itself
operator	organisation responsible for operation of the installation and with responsibility for safety and environment
potential loss of life	number of personnel who may lose their lives as a consequence of failure of a component
performance standard	benchmark against which actual performance is measured
probability	quantitative expression of the chance of an event occurring within a given period
probability of detection	probability that a given damage in a component will be detected using a given inspection method
probability of failure	probability that a component will fail within a defined time period
probability of failure ranking	comparative listing of probability of failure for one item against another, without reference to a value for probability of failure
quantitative risk assessment	process of hazard identification followed by numerical evaluation of event consequences and frequencies and their combination into an overall measure of risk

Term	Definition
risk	measure of possible loss or injury expressed as the product of the incident probability and its consequences
risk acceptance limit	limits above which the operator will not tolerate risk on the installation
risk-based inspection	decision making technique for inspection planning based on risk defined as the probability of failure and consequence of failure
risk type	risk expressed for a specific outcome, such as safety for personnel, economic loss or environmental damage
safety risk	risk to personnel safety expressed in terms of potential loss of life per year
segment	system of components forming part of the same pressure system, such as pipes, valves, vessels, that can be isolated by valves automatically closing in emergency shutdown
system	combination of piping and equipment intended to have the same or similar function within the process
tag number	unique identification of a part, component, pipe or equipment
time to failure	duration from a specified point in time until the component suffers failure
verification	confirmation, through the provision of objective evidence, that specified requirements have been fulfilled, ISO 9000

1.6.3 Abbreviations

The abbreviations described in Table 1-5 are used in this document.

Table 1-5 Abbreviations

Abbreviation	Description
AFFF	aqueous film-forming foam
ALARP	as low as reasonably practicable
APB	acid producing bacteria
API	American Petroleum Institute
ASME	American Society for Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
ATP	adenosine triphosphate
CoF	consequence of failure
CoV	coefficient of variance
CRA	corrosion resistant alloy
CS	carbon steel
CUI	corrosion under insulation
DFI	design, fabrication, installation
DFI&O	design, fabrication, installation & operation

Abbreviation	*Description*
EA	extended-analysis
EDS	energy dispersive x-ray spectroscopy
ESCC	external stress corrosion cracking
ESD(V)	emergency shut down (valve)
FAR	fatal accident rate
FORM	first order reliability method
FRP	fibre reinforced polymer
GC	gas chromatography
GVI	general visual inspection
HPIC	hydrogen pressure induced cracking
HPLC	high-performance liquid chromatography
IOB	iron oxidizing bacteria
MA	methanogenic archaea
ME	microbial equivalents
MFG	microbial functional groups
MIC	microbiologically influenced corrosion
MMM	molecular microbiological methods
MPN	most probable number
NDT	non-destructive testing
NGS	next generation sequencing
NRB	nitrate reducing bacteria
PFD	process flow diagram
PLL	potential loss of life
PoD	probability of detection
PoF	probability of failure
PREN	pitting resistance equivalent number
PSD	process and safety diagrams
P&ID	piping and instrumentation diagram
QA	quality assurance
qPCR	quantitative polymerase chain reaction
QRA	quantitative risk analysis
RAM	reliability availability maintainability
RBI	risk-based inspection

Abbreviation	*Description*
RCM	reliability centered maintenance
RP	recommended practice
SEN	scanning electron microscopy
SHE	safety, health and environment
SOHIC	stress oriented hydrogen induced cracking
SMYS	specified minium yield strength
SRA	sulphate reducing archaea
SRB	sulphate reducing bacteria
SS	stainless steel
SSC	sulfide stress cracking
SU	sample units
TDS	total dissolved solids
TEG	triethylene glycol
THPS	tetrakis tydroxymethyl phosphonium sulphate
TRA	total risk analysis
UFD	utilities flow diagram
UNS	unified numbering system
VFA	volatile fatty acids
XRD	x-ray diffraction

SECTION 2 RISK-BASED APPROACH

2.1 Integrity management approach

An important driver that influences the performance of a production plant, like an offshore oil and gas installation, is the high equipment utilisation achieved by minimising the equipment downtime by using reliable components, inclusion of redundant units and effective inspection and maintenance service. While meeting the high performance goals, the plant operators must also satisfy the stringent regulations for health, safety and environment (SHE). In order to successfully fulfil both, it is imperative that the loss of the technical integrity of the asset is kept to a minimum under specified operating conditions.

The maintenance of technical integrity comprises all activities that investigate the extent of decline in the performance of equipment and systems. The activities take into account the degradation processes and seek to prevent further degradation or, if the level or rate is unacceptable, repair or replace the degraded component.

Figure 2-1 shows a generalised maintenance management system that is required for a systematic integrity management of an asset.

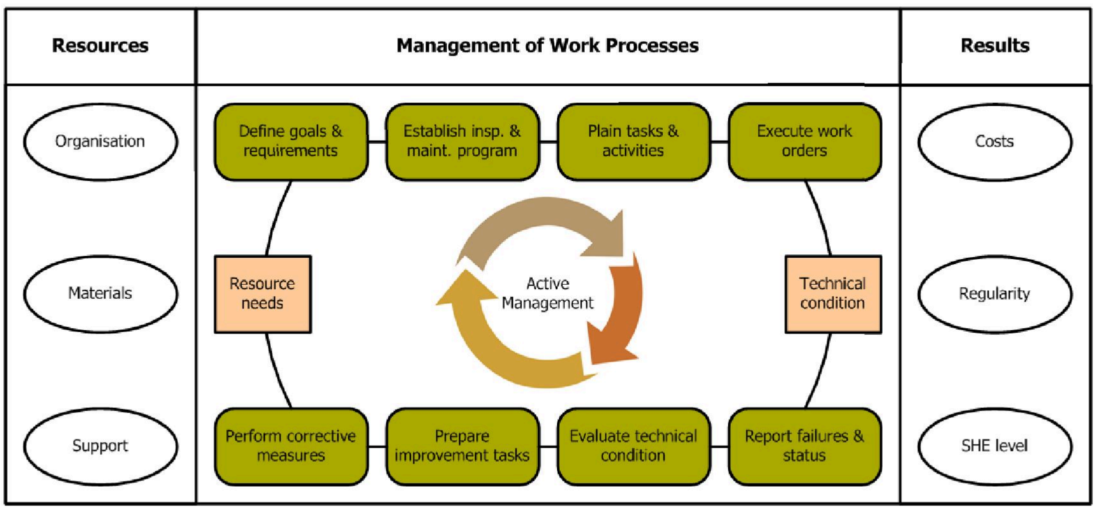

Figure 2-1 Maintenance management system

2.2 Basic risk management

The risk management approach applies a structured approach and makes the best use of the available knowledge towards assessing, mitigating to an acceptable level and monitoring risks. It does this by first identifying hazards. A hazard is anything that is a potential source of harm related to human injury, damage to the environment, damage to property or loss in production according to ISO 17776. The hazards are recorded in a hazard or risk register that defines how the hazard can develop into an accident, the potential accident consequences, and the safeguards in place that provide protection from the hazard. The hazards are then analysed for all reasonably foreseeable detrimental impacts they can have on the asset integrity and reliability.

Based on the hazard analysis, the associated risk is assessed by identifying possible failures, estimating the probability of failures, and assessing the consequence of failures. The extent and sophistication of the assessment depends on the anticipated magnitude of the risk. A coarse risk assessment of all hazards and a more detailed assessment of those with the greater potential to cause harm is generally conducted.

The results of the risk assessment are used for taking steps to reduce the impact of failure to as low as reasonably practicable (ALARP).

To reflect the changes in the operating environment and the need to monitor and maintain the performance of the resources allocated, the risk management process is a continuous activity.

During the risk management process the following tasks should be considered:

— Use risk and reliability analysis of asset performance data to support the assessment of opportunities for performance improvement.
— Manage the risks to asset integrity and reliability in projects and operations in accordance with good practice.
— Collect and assess data on asset performance as a basis for determining risk management measures.
— Develop appropriate performance standards for the effective management of risks to asset integrity and reliability.
— Maintain a current register of actions required to restore and maintain asset integrity and reliability.
— Check that actions to manage the risks to asset integrity and reliability are completed in a timely fashion and to an appropriate standard.

2.3 Maintenance and inspection planning

After carrying out the risk assessment inspection, test and maintenance activities are planned and executed according to a defined plan. The plan reflects the risk, i.e. probability and consequence, of equipment failure and the strategy to detect, prevent, control and mitigate potential failure. The condition of the equipment after inspection, test or maintenance actions is recorded and analysed and is used to update the risk-based plan. Figure 2-2 shows a generalised work process for establishing an inspection and maintenance programme.

The planning of maintenance and inspection should reflect the criticality of equipment and their performance standards developed from the risk management activities. It should seek to optimise the allocation of scarce resources, i.e people, specialist equipment, spare parts and consumables, to maintain the lifecycle value of the asset and not compromise production or SHE commitments.

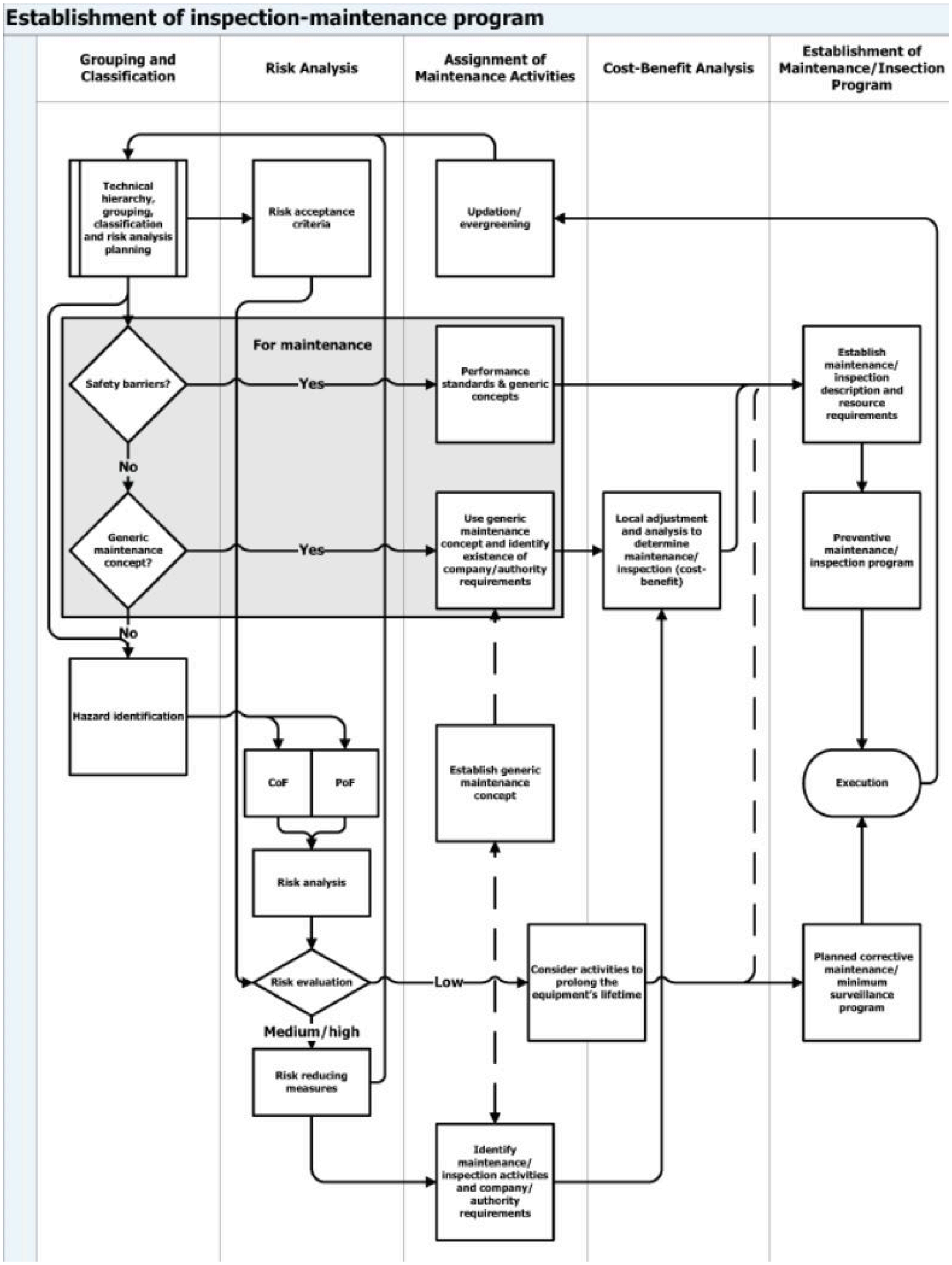

Figure 2-2 Work process for the establishment of inspection-maintenance programme

2.4 Inspection

Inspection is one of the many dedicated activities within offshore management that contribute to controlling and minimising offshore risks. The role of inspection is to check whether degradation is occurring, to measure the progress of that degradation, and to help ensure that integrity can be maintained. It provides assurance that asset integrity is maintained in accordance with the design intent.

Some important points to note about inspection are:

— Inspection activities provide specific, relevant, accurate and timely information to management on the condition of assets.
— Inspection activity is planned and executed with due regard for the policy and the risks to its achievement.
— Threats to asset integrity are identified sufficiently early so that they can be remedied cost-effectively with no appreciable impact on asset integrity or safety.
— The asset register stays current with the condition of assets and their inspection history.
— Inspection activity is scheduled to provide the necessary level of assurance of the condition of the plant and equipment while also minimising the detrimental impact on production operations.
— Equipment is handed over from operations to inspection personnel before the inspection activity, and from inspection to operations personnel following the inspection activity in accordance with a formal procedure which ensures that appropriate information on the equipment condition is exchanged.
— Inspection activity is subject to appropriate verification of its performance.

2.5 Risk-based inspection

Risk-based inspection (RBI) is a decision making technique for inspection planning based on risk – comprising the consequence of failure (CoF) and probability of failure (PoF). It is a formal approach designed to aid the development of optimised inspection, and recommendations for monitoring and testing plans for production systems. It provides focus for inspection activity, to address explicitly the threats to the asset integrity and its capability to generate revenue through production. Figure 2-3 shows the deliverables of an RBI assessment to the inspection program.

RBI is carried out for piping and vessels, including heat exchangers, tanks, pressure vessels, and filters. The scope of the RBI encompasses all pressure systems in the plant, whether hydrocarbon-containing or utility.

To carry out the RBI analysis for each item, the CoF and PoF are assessed separately. The two are then combined to obtain risk of failure. The evaluation is carried out separately for safety, i.e. addressing personnel death and injury, environmental, i.e. addressing damage to the environment and economic, i.e addressing financial loss.

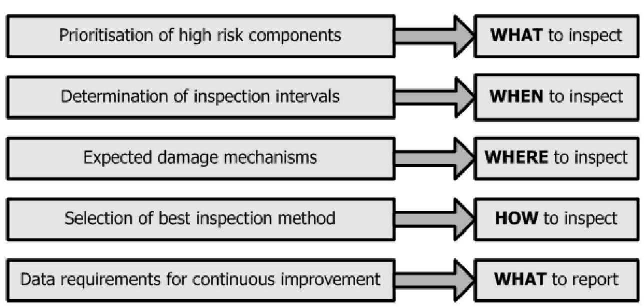

Figure 2-3 Deliverables of an RBI assessment to the inspection programme

Risk-based inspection methods and applications are also described in documents prepared by ASME and API. Inspection planning and execution standards are published by ASME and HOIS, see HOIS-RP-103, API 510, API 574, API 580, API 581.

2.6 Motivation for using risk-based inspection

Reasons for selecting a risk-based approach to inspection planning are:

— A systematic overview of the installation is achieved together with an explicit, systematic and documented breakdown of the installation's risks clearly showing the risk drivers and recommending appropriate actions.
— Inspection efforts are focused on items where the safety, economic or environmental risks are identified as being high. Similarly, the efforts applied to low-risk systems are reduced.
— Probabilistic methods can be used in calculating the extent of degradation and allow variations and uncertainties to be accounted for in process parameters, corrosivity, and thus degradation rates and damage extent.
— Consequences of failure are considered so that attention can be focused where it will have significant effect. If there are significant uncertainties in the outcomes, these can be modelled by investigating the probabilities of the various outcomes using an event tree approach.
— Contributing in a proactive and focused manner to ensure that the overall installation risk does not exceed the risk acceptance limit set by the authorities and operator.
— Identifying the optimal inspection or monitoring methods according to the identified degradation mechanisms and the agreed inspection strategy.

2.7 Inspection planning

The inspection planning judiciously allocates resources to carry out efficient and effective inspection to accurately determine the condition of the plant. It involves balancing the cost of inspection, including the necessary downtime, against the benefits of inspection, including the effectiveness of that inspection. The inspection planning process comprises three parts:

1) Risk based inspection analysis

   To decide the:

   1) parts of the plant that should be inspected
   2) degradation mechanism that should be considered
   3) level of inspection that should be carried out
   4) the time when the inspection should be carried out.

2) Development of an inspection frame programme

   It helps to develop an outline of the expected inspections with a long-term view of the future. The programme incorporates the RBI findings as well as experience and judgement related to the degradation that is not included in the RBI analysis.

3) Detailed inspection plan

   To interpret the findings of the RBI analyses and other plant experience to develop a precise plan. The plan should cover:

   1) type and technique of inspection
   2) preparation required
   3) the necessary inspection coverage
   4) level or quality of inspection.

2.8 Risk-based inspection and integrity evaluation

The use of risk-based principles acknowledges explicitly that it is cost-effective to allow some systems to fail as long as the consequences of that failure are sufficiently low. Some systems may also have such high consequences of failure that a failure is wholly unacceptable and should receive attention even when the probabilities of failure are low. The results may be difficult to interpret intuitively if the chosen RBI method is based on formal probabilistic methods because they take into account uncertainties in the risk assessments, not the probability of failure assessment.

These principles may challenge some accepted standards based on deterministic design and fitness-for-service standards, particularly where worst-case technical scenarios are used in the calculations without consequences of failure being taken into consideration. It is possible that there will be a discrepancy in the requirements for inspection and remedial action if such methods are directly compared with risk-based methods. Both cases would indicate that inspection is still required to monitor the progress of degradation, but the timing of inspection would be different for the deterministic and risk-based assessments.

There are a number of standards covering pressurised equipment, and these should be sought where needed. A number of standards have also been developed regarding the assessment of fitness-for-service and remaining life, the most comprehensive being API 579-1/ASME FFS-1. Such standards can be used to justify continued service when damage is found during inspection.

SECTION 3 RISK-BASED INSPECTION OVERVIEW

3.1 Introduction

Figure 3-1 illustrates the basic RBI concept. RBI is a systematic effort to try to understand both sides of the figure in order to plan inspection.

On the left side of the figure, the key concept is the degradation mechanism concept based on defined scenarios. This RP concentrates on the most common ones where inspection and monitoring efforts can be used to manage the associated risks. These degradation mechanisms are introduced in Sec.5 and App.C.

Each of the different degradation mechanisms may or may not lead to loss of containment. The PoF due to loss of containment can be estimated numerically, if a degradation model exists, or by means of engineering judgement. For more detailed recommendations regarding the assessment of these degradation mechanisms and associated failure probabilities, see Sec.5 and App.C.

Given that a loss of containment has occurred, the potential consequences will depend very much on the size of the hole, which can vary between a pinhole to a full bore rupture. This RP uses a fixed template with four potential hole sizes, see [5.4]. For each of the degradation mechanisms, this RP provides recommendations for the expected distribution of hole sizes. This information should be taken into account when considering the potential effect and consequences of any loss of containment, and can potentially affect the outcome materially.

Given a loss of containment, the consequences need to be assessed. Whether or not the loss of containment can lead to ignition or pollution is an important issue. For a general introduction to some consequence assessment principles, together with some end consequence descriptions and guidance, see Sec.6.

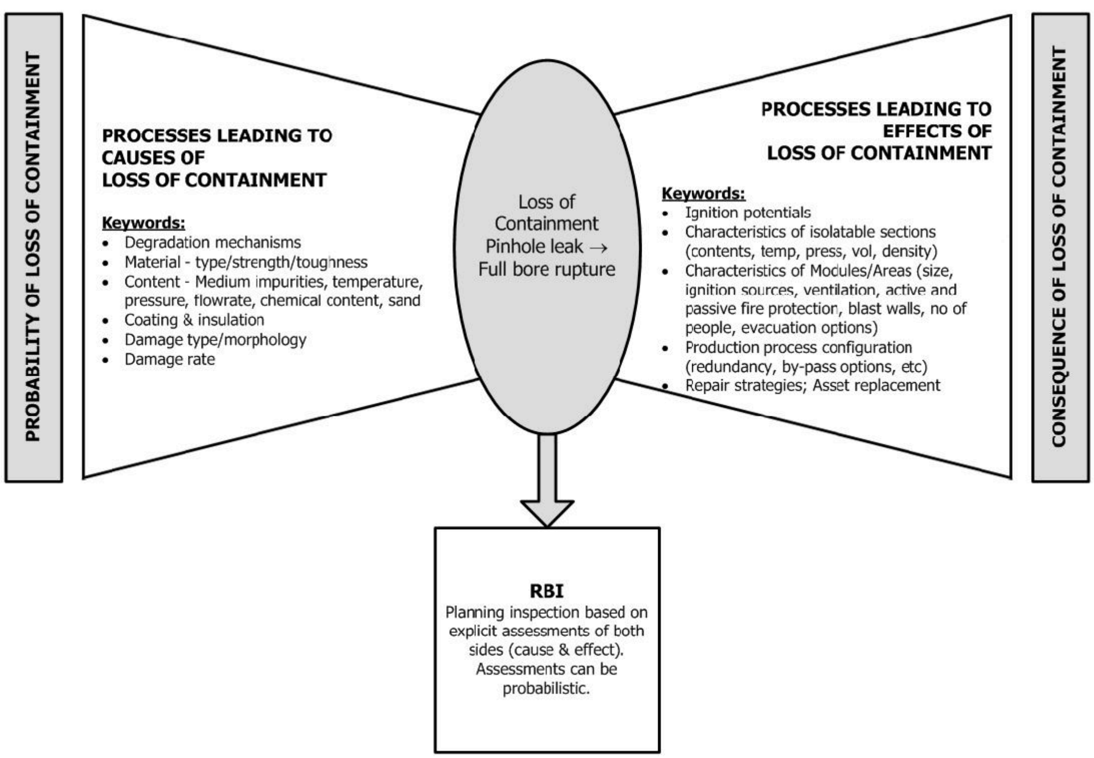

Figure 3-1 RBI basic concept

3.2 Risk-based inspection methods

Risk-based inspection can be carried out using methods that are qualitative or quantitative. In practice, most risk-based inspection efforts are carried out using a blend of both methods and, hence called a semi-quantitative method.

3.2.1 Quantitative

The quantitative model can be interpreted as a model-based approach where a numerical value is calculated when suitable models are available. Quantitative values can be expressed in qualitative terms for simplicity by assigning intervals for PoF and CoF, and assigning risk values to risk ranks.

The advantage of the quantitative approach is that the results can be used to calculate when the risk acceptance limit will be breached with some precision. The method is systematic, consistent and documented, and lends itself to easy updating based on inspection findings. The quantitative approach typically involves the use of a computer to calculate the risk and the inspection programme. The quantitative approach can initially be data-intensive, but removes much repetitive work from the traditional inspection planning process.

3.2.2 Qualitative

The qualitative model can be interpreted as an expert judgement-based approach in which a numerical value is not calculated and assigned. Instead a descriptive ranking is given, such as low, medium or high, or a numerical ranking such as 1, 2 or 3.

The advantage of using a qualitative approach is that the assessment can be completed quickly and at low initial cost, there is little need for detailed information, and the results are easily presented and understood. However, the results are subjective, based on the opinions and experience of the RBI team, and are not easily updated after inspection. It is not easy to obtain results other than a ranking of items in terms of risk. The variation of risk with time, allowing for estimation of inspection interval based on the risk acceptance limit is not possible.

3.2.3 Semi-quantitative and semi-qualitative

Methods are said to be semi-quantitative or semi-qualitative in the following cases:

— Parts of the RBI assessment are carried out using qualitative methods:
  — The CoF assessment is qualitative and the PoF assessment is quantitative.
  — The CoF and PoF assessments are quantitative, whereas the risk ranking and time to inspection assessment are qualitative.
— Assignment of PoF or CoF categories is done by simple algorithms based on a chosen set of the most relevant parameters.
— Assignment of PoF and CoF is made by engineering judgement.

3.3 Degrees of quantification

The following three degrees of quantification can be used:

— quantitative
— qualitative
— semi-quantitative / semi-qualitative.

The following are some recommendations with regard to degrees of quantification:

1) The RBI screening assessment, [4.7], should be a qualitative assessment, see App.A.

2) If the RBI detailed assessments are carried out in a qualitative manner:
   a) It should be done in the form of work sessions.
   b) Separate sessions should be organised for the degradation mechanisms assessment, CoF assessments, PoF assessments, and risk and inspection scheduling assessments.
   c) Sessions should be carried out at level 2, see [4.3].
   d) Each of these assessments should have their own set of assessment forms similar to the screening form in App.A. Guidance and prompting questions should also be established in a similar way.
   e) The set of assessment forms for degradation mechanisms should comprise, as a minimum, a separate form for each of the three groups:
      — internal degradation mechanisms
      — external degradation mechanisms
      — mechanical damage.

      Preferably, the set should include a separate form for each individual degradation mechanism.
   f) The same principle applies for the different consequence types being assessed.
   g) Risk matrices with decision procedures should be developed, agreed on and presented to all involved personnel before the work sessions.
   h) Qualified senior personnel, i.e. 10 years of experience or more, should be included in all sessions.
   i) A qualified senior RBI engineer from outside the group, either an external consultant or an engineer from another part of the organisation, should attend the sessions in order to ensure quality assurance (QA) verification.
   j) When the PoF assessment is qualitative:
      — Generally, numerical values/ranges should not be assigned. Only highly qualified personnel should be allowed to assign numerical values/ranges based on a qualitative engineering judgement assessment.
      — Generally, the risk assessment should be qualitative. If a numerical value/range has been assigned based on a qualitative PoF assessment, a quantitative risk assessment can be carried out, given a quantitative CoF assessment.
   k) When the safety CoF is qualitative, numerical values/ranges should not be assigned.
3) If the RBI detailed assessments are carried out in a quantitative manner:
   a) Quantitative PoF values have a wide range from zero to unity, and therefore a logarithmic scale is recommended for displaying the results graphically.
   b) A cut-off point is set for PoF below 10^{-5} as probabilities below this number are both difficult to model and observe, and will usually represent an insignificant risk.
   c) The safety consequence should be expressed in terms of potential loss of life (PLL) for personnel.
   d) The economic consequence should be expressed in financial terms using appropriate currency units.
   e) Environmental consequences can be expressed in terms of mass or volume of a pollutant released to the environment, or in financial terms as the cost of cleaning up the spill, including consideration of fines and other compensation.
   f) The consequence scale used in matrices and other presentations is necessarily different for PLL and currency, and should be selected to account for the full range of values.
   g) The CoF scale should advance in decades for each category, where the lowest category includes values up to the risk acceptance limit assuming that the PoF ≈ 1.0.
4) When both quantitative and qualitative methods are being used for a certain type of assessment, it is recommended to revisit and calibrate the qualitative assessments once the quantitative assessments are finalised.
5) Semi-quantitative / semi-qualitative methods based on simplified algorithms should be qualified by either external consultants or engineers from another part of the organisation.
6) It is an advantage to use a qualitative approach if there is little well-documented information.

7) In the cases where the team has considerable general experience and much experience for the specific installation(s) being assessed, it may be more efficient to choose a qualitative approach for the RBI detailed assessment even if the documentation is of good quality. In such cases, an underlying assumption is that the people involved will be available for future assessments and that the process is sufficiently documented.

3.4 Probability of failure

PoF is the probability of an event occurring per unit time, e.g. annual probability. It is estimated on the basis of the component degradation. PoF is related to the extent of, and uncertainty in, the degradation related to the component's resistance to its loading.

The recommended PoF scale used in the context of this RP is shown in Table 3-1. The table also shows the recommended qualitative ranking scale assigned to the quantitative PoF values.

Table 3-1 Probability of failure description

Cat.	*Annual failure probability*		*Description*
	Quantitative	*Qualitative*	
5	> 10^{-2}	Failure expected	(1) In a small population *), one or more failures can be expected annually.
			(2) Failures have occurred several times a year in the location.
4	10^{-3} to 10^{-2}	High	(1) In a large population **), one or more failures can be expected annually.
			(2) Failures have occurred several times a year in the operating company.
3	10^{-4} to 10^{-3}	Medium	(1) Several failures may occur during the life of the installation for a system comprising a small number of components.
			(2) A failure has occurred in the operating company.
2	10^{-5} to 10^{-4}	Low	(1) Several failures may occur during the life of the installation for a system comprising a large number of components.
			(2) A failure has occurred in the industry.
1	< 10^{-5}	Negligible	(1) A failure is not expected.
			(2) A failure has not occurred in the industry.
*) Small population = 20 to 50 components. **) Large population = more than 50 components.			

3.5 Consequence of failure

CoF is evaluated as the outcome of a failure given that such a failure will occur. It is defined for the three consequence types: personnel safety, environmental and economic.

It is generally recommended that CoF values or rankings be assessed and presented separately, depending on the consequence type, which allows each type to be addressed and given proper focus. It is especially important to assess the CoF values for each consequence type when using quantitative methods because it is not recommended to combine personnel safety and economic consequences.

Examples of qualitative and quantitative ranking scales that can be used for the CoF are shown in Table 3-2 and Figure 3-2.

Table 3-2 Consequence of failure qualitative ranking scales in accordance with ISO 17776

Rank	*CoF personnel safety*	*CoF environment*	*CoF economic*
A	Insignificant	Insignificant	Insignificant
B	Slight/minor injury	Slight/minor effect	Slight/minor damage
C	Major injury	Local effect	Local damage
D	Single fatality	Major effect	Major damage
E	Multiple fatalities	Massive effect	Extensive damage

PoF Ranking	PoF Description	A	B	C	D	E
5	(1) In a small population, one or more failures can be expected annually. (2) Failure has occurred several times a year in the location.	YELLOW	RED	RED	RED	RED
4	(1) In a large population, one or more failures can be expected annually. (2) Failure has occurred several times a year in operating company.	YELLOW	YELLOW	RED	RED	RED
3	(1) Several failures may occur during the life of the installation for a system comprising a small number of components. (2) Failure has occurred in the operating company.	GREEN	YELLOW	YELLOW	RED	RED
2	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	GREEN	GREEN	YELLOW	YELLOW	RED
1	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	GREEN	GREEN	GREEN	YELLOW	YELLOW
CoF Types	Safety	No Injury	Minor Injury Absence < 2 days	Major Injury Absence > 2 days	Single Fatality	Multiple Fatalities
CoF Types	Environment	No pollution	Minor local effect. Can be cleaned up easily.	Significant local effect. Will take more than 1 man week to remove.	Pollution has significant effect upon the surrounding ecosystem (e.g. population of birds or fish).	Pollution that can cause massive and irreparable damage to ecosystem.
CoF Types	Business	No downtime or asset damage	< € 10.000 damage or downtime < one shift	< € 100.000 damage or downtime < 4 shifts	< € 1.000.000 damage or downtime < one month	< € 10.000.000 damage or downtime one year
CoF Ranking		A	B	C	D	E

Figure 3-2 Example of a risk matrix in accordance with ISO 17776

3.6 Estimation of risk

The risk associated with a failure from a given degradation mechanism is estimated as the combination of the PoF and the CoF. The PoF and CoF can be estimated in either a qualitative or quantitative manner, or by using a combination of qualitative and quantitative methods.

The risk can be presented as a matrix and allows the relative contribution of both factors to be seen, i.e. CoF and PoF. While the matrix is a static picture of risk, calculated for any one time period, matrices can be prepared for different time periods to illustrate development of risk.

Separate matrices for each risk type are recommended, especially when quantitative methods are used. The matrix should be standardised for each operator/field in order to simplify communication and the decision process. To achieve adequate resolution of detail, a 5 by 5 matrix is recommended.

It is recommended that the results are checked for the validity of any assumptions that were made during the assessments, the correctness of data used, and that the risk outputs are broadly in agreement with those given in any relevant safety case, quantitative risk analysis (QRA) or similar documentation. Notice that QRA / Safety case studies and RBI studies have different objectives, and utilise somewhat different data and equations. Consequently, it is likely that results from the different studies will not be in exact agreement.

An example of a qualitative assessment matrix in accordance with ISO 17776 is shown in Figure 3-2. The matrix has PoF on the vertical axis, and CoF on the horizontal. The divisions between the categories should be chosen by taking into consideration the absolute magnitude of the values and their ranges, relevant for quantitative assessments, and the need for consistent reporting when comparing different installations.

The risk matrix shows three risk levels, identified by colour:

— Green (low risk): risk is acceptable. Generally, action needs to be taken to ensure that the risk remains within this region. Typical actions involve operator rounds, cleaning, and general visual inspections (GVI) to confirm that there have been no changes in the equipment condition.
— Yellow (medium risk): risk is acceptable. Non-destructive testing (NDT), functional tests or other condition monitoring activities should be performed to measure the extent of degradation so that action can be taken to ensure that risks do not rise into the red high-risk region.
— Red (high risk): risk level is unacceptable. Action shall be taken to reduce PoF, CoF or both, so that the risk lies within the acceptable region.

The risk assessment can be implemented using:

— Risk prioritisation methods: rank equipment and systems in terms of risk magnitude, and address the highest risk equipment first.
— Risk acceptance limit methods: estimate risk per equipment and its change with time, and address equipment where risk will cross the risk acceptance limit first.

SECTION 4 RECOMMENDED WORKING PROCESS

4.1 Introduction

This section presents an overview of a recommended RBI work process. The material presented in this section together with the material presented in the appendices can be used to further develop and customize the RBI assessment working processes.

It is important to emphasise that the basic RBI process presented in this section can be applied to different detail levels, from installation level down to inspection point level. In order to manage the complexity of the task of planning inspection for a topsides installation, it is recommended to apply a top-down approach and take care to choose appropriate combinations of qualitative and quantitative methods. [4.3] covers assessment detail levels and the rest of the section presents the recommended RBI working process.

4.2 Basic working process

The basic risk-based inspection process is presented in Figure 4-1.

The working process has been divided into five stages:

1) information gathering
2) screening assessment
3) detailed assessment
4) planning
5) execution and evaluation.

The RBI assessment should be reviewed on a regular basis, and revised as necessary to account for any significant changes in the input information, e.g. in process and operational data, new design conditions, and changes in field economy. For most offshore processing systems the operational conditions are subject to both short-term and long-term changes due to operational practices and reservoir characteristics. It is essential to track such changes and to take appropriate actions based on these. Some changes can be anticipated, such as a tie-in to a new well of a different composition.

4.3 Level of detail

Before beginning the evaluations, the assessment level of detail for the evaluations should be established and agreed on. It should account for the level of detail required by the inspection planners, who work with the results of the assessment, as well as the amount and detail level of input data available. The equipment level hierarchy can be useful in connection with making choices as to how the inspection planning process shall be defined and specified. The level of detailing may be increased for the high-risk items. The assessment process may start at level 0, resulting in high level plans for a number of installations, and proceed to level 1 for certain individual installations and move on all the way down to level 3 for selected items.

It should be noted that inspection planning is concerned with the smallest level of detail, i.e. level 4: inspection point, so if the RBI assessment is carried out at a higher level, more time will be used in the final inspection planning process than if the RBI is executed either directly at a more detailed level, or in a manner that can be easily transferred to such a level.

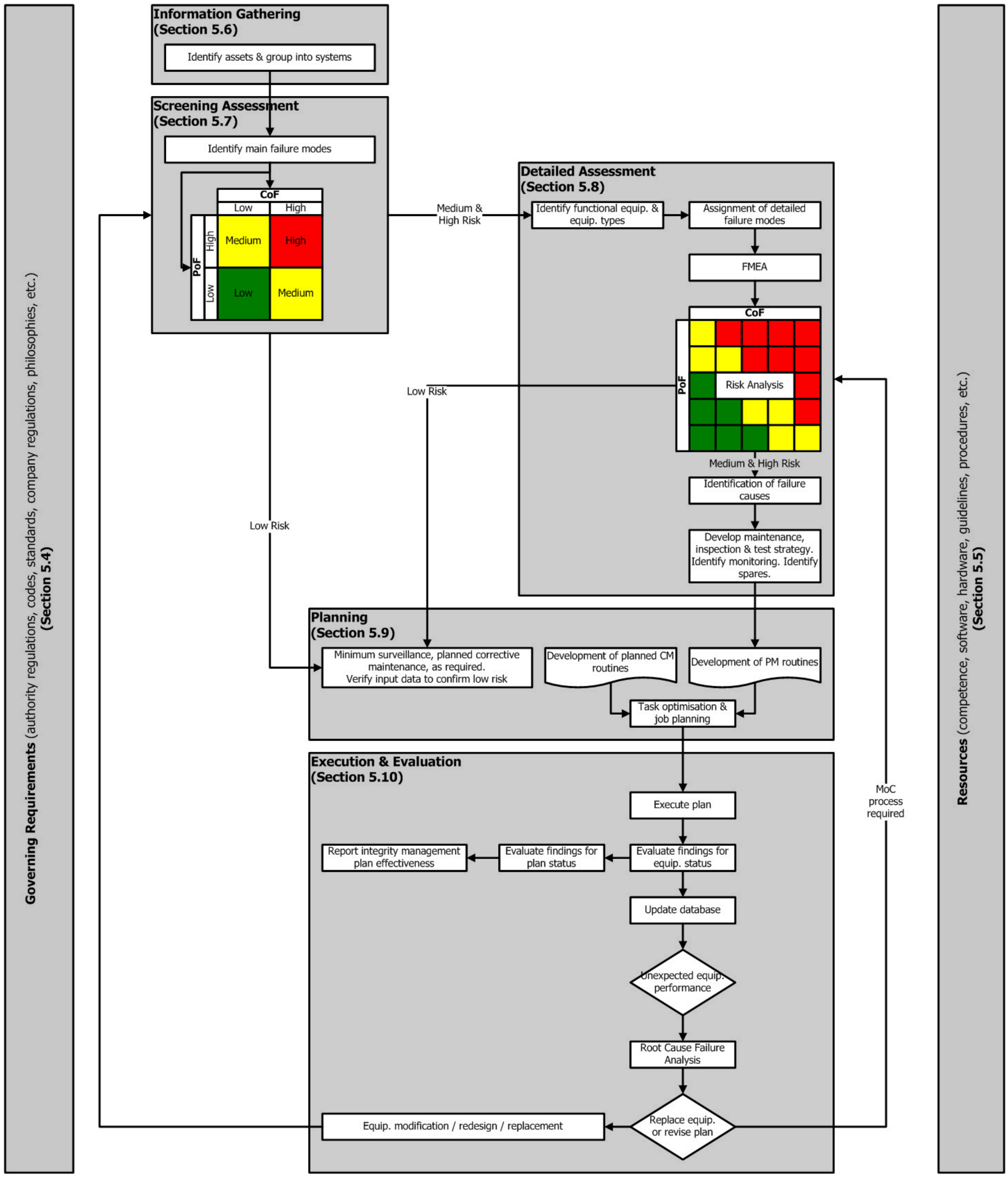

Figure 4-1 Basic risk-based inspection process

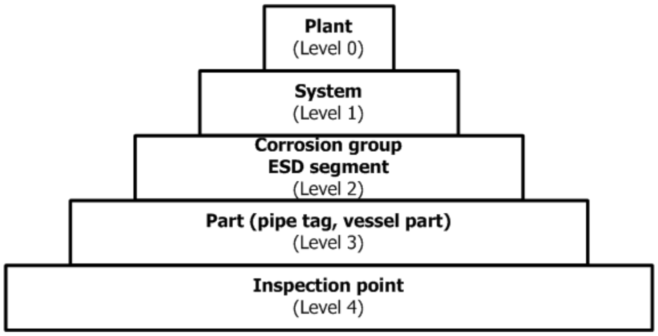

Figure 4-2 Asssement detail level hierarchy

Figure 4-2 shows the various assessment levels that can be used. Guidance to the different levels is presented below:

Level 0 refers to the plant/installation level. An assessment at level 0, taking into account a number of plants, can be useful to carry out in connection with, e.g. budget prioritisations and distributions. Such an assessment is assumed to be carried out based on high level information. Examples of such information are the number of people on installations, location of installations, production numbers, historical information regarding availability, production interruptions related to failures by loss of containment, types of materials used on installations, presence of H_2S, CO_2 and sand on installations. An assessment at level 0 lends itself to both qualitative and quantitative evaluations. It is very likely that the team will be able to use engineering judgement and evaluate most aspects in a qualitative manner. Level 0 is not covered any further in this RP.

Level 1 refers to the system level. Examples of systems are the separation and stabilization system, the metering system, the closed drain system, the open drain system and the flare system. Carrying out an assessment at this level for the purpose of directly producing an inspection plan is unusual. An assessment at Level 1 is normally used to identify the systems that significantly contribute to the risk levels of the installation. Further assessment efforts at lower levels can be focused on these systems, whereas the remaining systems can be considered for other types of maintenance activities. An assessment at level 1 is recommended to be carried out in a qualitative manner.

Level 2 refers to the corrosion group or ESD segment level. An assessment at level 2 is used to identify groups at a level which is more meaningful and practical from an inspection plan point of view. It is important to define groups of components so that the assessment for one component can be applied to all the others within that group. Grouping is typically carried out with reference to process flow diagrams (PFD) and piping and instrumentation diagrams (P&ID). It is likely that different groups will be defined for the assessment of PoF, e.g. different types of corrosion groups, and CoF, e.g. ESD segments. Unlike an assessment at level 1, an assessment at level 2 can be significantly time-consuming, the first time it is carried out. One of the main reasons is that the definitions of groups are rarely available and are therefore often generated manually. An assessment at level 2 can be carried out in both a qualitative and a quantitative manner. Once the groups are in place, it is possible to either carry out the assessments on representative cases of the groups and transfer the results to level 4 for planning of inspection points, or continue to level 3 by linking component parts to groups and adjust the assessments based on more detailed part information. When working at level 2, it is recommended to plan the work based on well-defined, manageable sections of the installation, preferably system by system.

Level 3 refers to the pipe tag / vessel part level. An assessment at level 3 is used to develop an inspection plan and is normally based on transferring results from a level 2 assessment down to a part level. It may be relevant to analyse certain specific parts, but a separate assessment of every part at this level is not practical. A good line list is necessary in order to carry out an assessment at this level. For the same reasons as mentioned above, an assessment at level 3 can be time-consuming. Line lists do not normally have links to the groups from the level 2 assessment, so the links have to be done manually. An assessment at level 3 is dependent on a good electronic line list and good software support. Assuming that the line list is complete and of a good enough quality, the advantages of carrying out a level 3 assessment are that:

— All sizes of the part and all materials are considered.
— It is less likely that parts will be overlooked.
— All parts of the vessel/tag are considered.
— It allows unusual cases and well-understood equipment and degradation mechanisms to be included separately.
— Identification of high-risk vessel parts may save intrusive inspection.
— Separate degradation mechanisms found in specific locations in the vessel/tag are evaluated separately.
— The greatest precision in updating assessment with inspection findings may be achieved.

When working at level 3, it is recommended to plan the work based on well-defined, manageable parts of the installation, preferably system by system and group by group.

Level 4 refers to the inspection point level. RBI assessments at level 4 are only carried out for inspection points of special concern. Results from assessments at level 2 or level 3 are usually transferred down to level 4 where inspection points are identified and chosen in isometric drawings. When working at level 4, it is recommended to plan the work based on well-defined, manageable parts of the installation, preferably system by system and group by group.

4.4 Governing requirements

Constraints and control mechanisms in the form of different governing documents, like maintenance and inspection philosophies, as well as regulatory requirements, should also be available to the RBI team. Risk acceptance limits are typically derived from such documents.

4.5 Resources

4.5.1 Competence/personnel

RBI assessment and inspection planning is a multidisciplinary activity, and the following qualified and experienced personnel should be involved:

— Inspection engineers with hands-on experience of inspection of piping, pressure vessels, heat exchangers, both in-service and during construction.
— Materials/corrosion personnel with expertise in materials selection, corrosion monitoring and control, chemical treatments, fitness-for-service assessments, coatings and linings.
— Safety/consequence personnel with experience in formal risk assessment covering personnel safety, economic and environmental disciplines.
— Plant operations and maintenance personnel with detailed knowledge of the installation.

Furthermore, successful implementation of RBI requires competent personnel carrying out the different roles and responsibilities within the inspection discipline as a whole. Communication of the results from the RBI assessment team to the inspection planning team is critical. Experience has shown that close cooperation between the RBI analysis team and the inspection planning team has been a very important success factor. Ideally, these two teams should be completely integrated.

4.5.2 Roles and responsibilities

The roles and responsibilities are organised differently by the different operator companies, but in general the activities can be split into the following tasks:

- Inspection management:
  - overall planning of the inspection activities
  - co-ordinating the inspection activities with the maintenance and operations superintendents
  - hiring any necessary inspection consultant competence and resources to serve, accommodate, and maintain the inspection system
  - supervising the inspection activities
  - co-ordinating laboratory services, material testing, and sampling
  - providing QA of the inspection activities
  - documenting and reporting inspection findings and results
  - ensuring that experience feedback is used for annually updating the scope and plan for future inspections
  - evaluating the plant condition
  - maintaining and improving the inspection system.
- Inspection planning:
  - establishing framework inspection programmes
  - establishing detailed inspection programmes
  - co-ordinating inspectors, equipment and performing other logistic services related to inspection execution
  - update inspection programmes based on inspection results and changes of operational parameters
  - gathering necessary documentation and information to optimise the inspection programme
  - documentating and reporting inspection activities
  - evaluating the plant condition.
- Assisting in RBI assessments:
  - inspection execution and reporting
  - managing and performing inspection work
  - supervising NDT Operators
  - making first-hand evaluation on the inspection site
  - reporting to inspection management
  - obtaining work permits relevant to inspection activities
  - performing QA on the inspection work
  - performing NDT
  - reporting completed testing to the senior inspector.

Requirements for inspection execution are handled by the inspector qualification schemes, such as those in accordance with ASNT standards and ISO 9712. Requirements for in-service inspection personnel covering the whole process from management through to execution, reporting and evaluation shall be defined.

4.5.3 Procedures, tools and technology

Implementation of RBI requires appropriate procedures and software tools.

It is an advantage to have well documented company RBI working procedures before committing to, or developing, software solutions. Such working procedures should be part of the basis for software specification/customization. It is also an advantage to specify the data management needs when choosing or developing software solutions, which can be done by specifying and maintaining a conceptual information schema.

4.6 Gathering information input

Typical examples of input sources for carrying out the RBI evaluations are:

- line list

— equipment list
— system descriptions manual
— engineering numbering system
— equipment data and vessel sheets
— piping data sheets
— layout drawings, process flow diagrams (PFDs), utilities flow diagrams (UFDs), P&IDs, process and safety diagrams (PSDs)
— design, fabrication and installation (DFI) resume
— inspection/failure/replacement details
— inspection/failure/replacement history knowledge
— corrosion protection philosophy
— material design specification and selection report
— coating specifications
— insulation specifications
— QRA
— design accidental load analysis
— ESD logic diagrams
— mass balance sheets
— production data, i.e. past and future
— key operation and maintenance personnel.

In the absence of such information, assumptions may be based on judgement and experience. All such assumptions should be recorded. In case sufficient information is not available, the use of RBI should be avoided.

There are three main groups of input data needed to carry out a risk-based analysis, which is used as input to the inspection planning:

— inspection data
— consequence data
— engineering/process data.

Some effort should be put into understanding the sources of information and streamlining the interfaces to these sources.

— Inspection data
  Specifications should be made for what is expected back from inspection activities in order to satisfy the models used in the analysis. Each degradation mechanism should have its own specification. Furthermore, procedures should be described for updating calculations. These procedures should include what kind of statistical analyses need to be carried out, and how.
— Consequence data
  Specifications should be made for what is expected from quantified risk analysis reports. Safety consequence results from such analyses should be reported in such a way that they are ready to use for inspection planning purposes. The challenge of transferring the results to a detailed level, e.g. pipe tag, can be solved by specifying requirements to the engineering disciplines that generate line lists, P&IDs, PFDs, etc. The link between low level components and higher level groupings should be documented in a way that eases the inspection planning work. Likewise, it may also be beneficial to have a link between low level components and higher level groupings for economic consequence information.
— Engineering and process data
  Basic input data, such as dimensions, pressure, and temperature, can also be difficult to manage, and will depend on the quality of the interfaces to the engineering and operation disciplines that generate this information.

4.7 Screening assessment

The purpose of the screening process is to identify, at a higher level, typically level 2 and upwards, the elements that are judged to make a significant contribution to the risk levels. The screening ensures that further data gathering and assessment efforts can be focused on these high-risk elements. For a given installation, screening is typically carried out in a qualitative manner that involves identification of risk on a system by system, group by group, or major equipment item level. On the basis of installation history and future plans and possible components' degradation, the CoF and PoF are each assessed separately to be either 'significant' or 'insignificant', resulting in 'high', 'medium' and 'low' risks, as seen in the matrix given in App.A.

Generally, low-risk items will require minimal inspection, and be supported by maintenance. Medium-risk and high-risk items will require a more detailed evaluation, which is the subject of the second stage of the working process. Inspection data is used only as general guidance, as the screening is intended to identify systems, groups and equipment where it is cost-effective to use a more time-consuming detailed assessment. More guidance on RBI screening is given in App.A.

4.8 Detailed assessment

The elements with medium and high risk from stage one, i.e. RBI screening, are the elements that shall be considered in more detail, i.e. broken down to lower levels and evaluated with either qualitative, quantitative or semi-quantitative methods. The objectives of this stage of the assessment are to identify the relevant degradation mechanisms, estimate the extent of damage, estimate when inspection should be carried out, and propose what inspection technique should be used to ensure acceptable risk levels. It is recommended to work at level 2, i.e. corrosion groups or ESD segments, and transfer results down to level 3 or level 4.

Figure 4-3 shows the flow chart for carrying out a detailed RBI analysis.

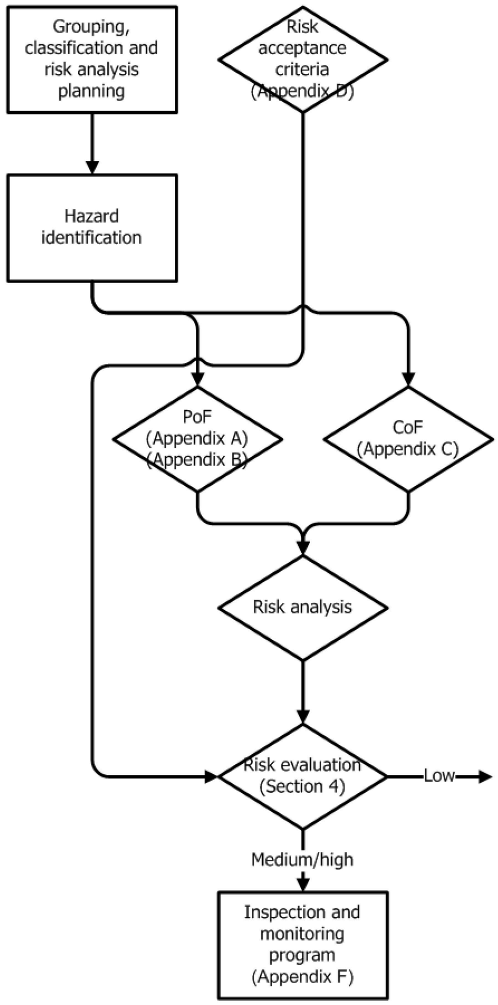

Figure 4-3 Detailed risk-based inspection assessment working process

4.9 Planning

In many cases the results of the RBI screening and detailed assessments are used as input to the final inspection planning stage, where a different team of planners work at the inspection point level and may take into account other factors and also consider logistics before finalising the plan.

The interaction between the planners and the RBI analysts may result in more refined RBI assessments carried out for certain parts or inspection points. Guidance on inspection planning is given in App.D.

The assessment provides a preliminary inspection plan, including inspection methods and timings that are readily updated as inspection data becomes available. A final executable inspection plan will normally be developed based on this preliminary plan, but also considering:

— Logistics, including available bed space, available personnel, and need for specialised equipment.
— The need for interaction with maintenance activity.
— The asset ready for inspection by operations personnel, including extent of shutdowns necessary.

— Database setup, capabilities and equipment hierarchy and possibly other factors that have not been covered by the RBI assessment.

The results from this part of the assessment provide the basis for the final detailed inspection planning. A report shall be focused on the needs of the inspection planner. Typically, the report will comprise the risk results collated with any intermediate calculations related to part and process data. Additional consideration should be given to the data requirements and capabilities of any inspection planning tools that are used.

The assessment and underlying assumptions should be documented, together with a combination of the following information, as required, related to each item:

— Component/system identification.
— Materials of construction, fluid type, operational conditions, design limits.
— Equipment/segment volumes, economic data related to lost/deferred production.
— Inspection and operating history.
— Degradation mechanisms and failure mode, damage rate, uncertainty and basis.
— Safety risk, economic risk and risk categories.
— Risk in relation to the risk acceptance limit.
— Time to reach risk acceptance limits.
— Key indicators for risk change, e.g. temperature, process changes.
— Recommendations that the part be subject to inspection, maintenance activities or monitoring of process or other parameters.
— Recommendations for additional activities in verifying the data and assumptions used in the assessments.

4.10 Execution and evaluation

The overall recommendations and guidelines presented in all of the above sections need to be further customized.

For an analysis to be effectively implemented as a well-managed inspection plan, the data needs to be transferred to an inspection management database. The amount and extent of data transferred and uploaded will depend on the capability of the database as well as the data available. Many databases not only manage the detailed tag-based data, but can alsocarry out trending analyses, store pictures, documents, data files and videos, as well as communicate directly with the NDT equipment.

Prior to transfer of data, the following issues should be considered:

1) Data quality: the quality of the data to be transferred should be checked as far as possible prior to upload, as it is usually easier to correct at that stage. Data relationships, i.e. hierarchy, should be maintained as for the installation asset register, to facilitate coordination with maintenance data.
2) Working process: the working process for both data upload as well as maintaining the data up to date with inspection findings, plan updates, tag data changes, and more, should be carefully evaluated. Maintenance of data integrity is essential, as is the exclusion of errors, but other points to consider are whether complex programming is needed if data transfer is to be infrequent.
3) Updating: in case of updating the main asset database with revised inspection plans, consideration shall be given to implementation of a formal change management process, so that changes to plans and data are properly assessed by competent personnel for their effects on installation safety and operations.
4) Data storage: locations for data storage should be considered. In the life of an installation, a great deal of data and information will be generated, and the pros and cons of using the inspection management database, external databases, or simple folder structures to manage the data should be evaluated. The need for easy access to data in case of a network failure or damage to a server should be included in the evaluation.
5) Infrastructure capacity: if the inspection management database shall be made available with all functionality offshore or at remote locations, and the data server shall be maintained at remotely, consideration, shall be given as to whether the data links will be sufficient to handle the necessary traffic, in addition to normal operational traffic. It may be necessary to implement a daily update from one server to another when the network is quieter, as opposed to live data in both locations.

SECTION 5 DEGRADATION MECHANISMS AND PROBABILITY OF FAILURE ASSESSMENT

5.1 Introduction

The purpose of this section is to guide the RBI analyst to:

— Identify which degradation mechanisms can be expected where.
— Determine damage rates and PoF for some specific materials exposed to specified service conditions.
— Present a number of simplified models for internal and external degradation.

It is emphasised that these degradation models are not exhaustive but are recommended to secure a consistent and documented methodology when better data is not available.

5.2 Degradation mechanisms

The degradation of a component can take place externally and internally. The rate at which the degradation takes place at the two surfaces depends upon the combination of the following parameters:

— material of construction
— contents of the part, i.e. product services for internal degradation
— environment surrounding the part for external degradation)
— protective measures
— operating conditions.

Internal and external degradation mechanisms should be defined for each part using the guidance and tables given in [5.6] to [5.13]. Assumptions used in these subsections shall be checked and confirmed to be applicable for the circumstances related to the individual part. If the assumptions are not valid, then specialist assistance should be sought to evaluate the specific circumstances. Assessment of the degradation mechanism fatigue is treated in a separate appendix, see App.C

The applicable degradation mechanisms should be listed for each part, together with the reasons for selection.

Table 5-1 gives the types of materials that are discussed in this document.

Table 5-1 Definition of materials

Material type	*Description*	*Includes*
CS	carbon steel	Carbon and carbon-manganese steels, low alloy steels with a specified minimum yield strength (SMYS) less than 420 MPa.
SS	stainless steel	Austenitic stainless steel types UNS S304xx, UNS S316xx, UNS S321xx or similar. 22Cr duplex UNS S31803 and 25Cr super-duplex UNS S32550, UNS S32750 stainless steels or similar. Super austenitic stainless steel type 6Mo, UNS S31254.
Ti	titanium	Wrought titanium alloys.
CuNi	copper nickel alloys	90% Cu / 10% Ni or similar.
FRP	fibre reinforced polymer	Fibre reinforced polymer materials with polyester or epoxy matrix and glass or carbon fibre reinforcement.
Ni	nickel-based alloys	Nickel-based alloys.

Material type	Description	Includes
Other	material other than the above	All other materials not described above.

5.3 Understanding probability of failure

This RP is primarily intended to be used for the planning of in-service inspection for offshore topsides static mechanical pressure systems when considering failures by loss of containment of the pressure envelope. 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, R, is primarily related to the materials, the design, and the in-service condition of the structure. The load, L, can be any type of load: functional, environmental or accidental. The reasons why the applied load can exceed the resistance are many: poor design specification, design errors, material defects, fabrication errors, degradation in operation, and other unknown events.

The total probability of failure (PoF_{Total}) is the sum of the probabilities of all events that can cause a failure. It can basically be summarised as follows:

$$PoF_{Total} = PoF_{Technical} + PoF_{Accidental} + PoF_{Gross\text{-}error} + PoF_{Unknown}$$

where:

$PoF_{Technical}$ = natural uncertainties in design loads and load bearing capacities
It is due to fundamental, natural, random variability and normal man-made uncertainties

$PoF_{Accidental}$ = the probability of 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.

$PoF_{Gross\text{-}error}$ = the probability of gross errors during DFI and operation
Gross errors are understood to be human mistakes. Management systems addressing, e.g. training, documentation, communication, project specifications and procedures and quality surveillance, are all put in place 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 in a project. 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 avoid gross error leading to failure.

$PoF_{Unknown}$ = the probability of unknown or highly unexpected phenomena
Truly unimaginable events are very rare, hard to predict and should be a low contribution to failure Therefore, there is little value in estimating these probabilities. It is worth noting that even though incredible events have low probability, they can have very high consequences, thus increasing the risk. However, interested parties are, in general, more likely to accept consequences of truly incredible events when they have occurred.

5.3.1 Quantitative assessment methods

When estimating the PoF in a quantitative manner for the purpose of planning inspection, it is $PoF_{Technical}$ that is normally addressed. Though it is unusual, $PoF_{Accidental}$ can also be addressed. $PoF_{Gross\text{-}error}$ and $PoF_{Unknown}$ are not addressed in quantitative evaluations. Using full probabilistic models to estimate the PoF can become complex and time-consuming in the context of topside risk-based inspection. Simplified models are presented in this section.

5.3.2 Qualitative assessment methods

When estimating the PoF in a qualitative manner for the purpose of planning inspection, one can assume that all elements are represented in the evaluation, if experienced and competent personnel are involved.

5.4 Hole size template

This RP uses a set of predefined hole sizes that are related to those given for the degradation mechanisms. The expected percentage of holes falling within each category can be estimated for each mechanism. Table 5-2 shows the recommended hole sizes that are referenced in both the CoF and the degradation mechanism assessments. Sec.6 gives guidance on how to adjust and utilise this type of information when assessing the CoF.

Table 5-2 Hole size category and the corresponding hole diameters

Small holes	hole diameter ≤ 5 mm
Medium holes	5 mm < hole diameter < 25 mm
Large holes	25 mm ≤ hole diameter
Rupture, full release	component diameter < hole diameter

5.5 Degradation modelling and probability of failure evaluation

The purpose of the degradation modelling and PoF evaluation is to assess:

— current PoF for each tag
— evaluate the development of damage, hence PoF, with respect to time
— expected damage that may be incurred by a component.

The expected damage rate models can be classified into three types:

(a) Insignificant model, see [5.5.1]

(b) Unknown model, see [5.5.2]

(c) Rate model, see [5.5.3]

(d) Susceptibility model, [5.5.4].

The behaviour of these models is shown schematically in Figure 5-1.

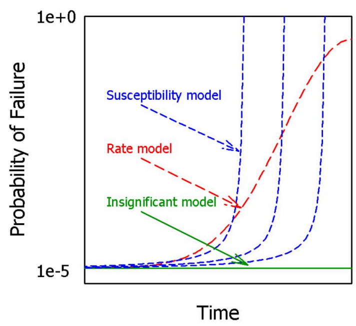

Figure 5-1 Schematic curve of degradation modelling

5.5.1 Insignificant model

For a component degrading according to the 'insignificant model', no significant degradation is expected. The model allocates a fixed probability of failure value, PoF = 10^{-5} per year, regardless of time, allowing a risk value to be calculated. Inspection of the components described by this model is not necessary except for checking that the premises have remained valid.

Hole sizes for analysis of consequences are given in Table 5-3 and are considered generally applicable in offshore systems.

Table 5-3 Hole size distribution for 'insignificant' systems

	% distribution		
Equivalent hole diameter	*Carbon steels*	*Stainless steel and nickel-based alloys*	*Titanium-based alloys*
Small hole	0	0	100
Medium hole	0	100	0
Large hole	100	0	0
Rupture	0	0	0

5.5.2 Unknown model

Where the product is an unknown substance, or the combination of materials and product has no defined model, then initially a PoF of 1 should be assigned and the need for further investigation driven by the CoF. A CoF will then give a high risk, indicating that it will be beneficial to spend further time investigating the product and materials.

The hole sizes required to calculate consequences are given in Table 5-4.

Table 5-4 Hole size distribution for 'unknown' systems

Equivalent hole diameter	*% distribution*
Small hole	0
Medium hole	0
Large hole	0
Rupture	100

5.5.3 Rate model

The rate model is normally applicable when the damage results in a local or general wall thinning of the component. It assumes that with time the extent of damage increases, resulting in a decrease of wall thickness, which in turn manifests itself as an increase in the PoF with time.

The rate of degradation, and hence, the rate of decrease in the wall thickness, is dependent upon a number of factors. These include:

— material properties
— wall thickness
— fluid properties

— operating conditions.

All these factors vary and a full probabilistic assessment should consider every factor as a stochastic variable. In practice, however, the uncertainties associated with the degradation drivers, e.g. pressure and flow rate, tend to outweigh the uncertainties of the other variables, which allows for some simplification without significant loss of precision.

A simplified rate model can be described by a distribution type, mean and standard deviation. This section suggests these parameters for different degradation scenarios.

The calculation of PoF can be carried out using Monte Carlo simulation or the first order reliability methods (FORM) using distributions for all the most important factors. These calculations are best carried out using computer techniques and are likely to require a specialist in mathematical and statistical techniques to develop the algorithms. A number of suitable software tools are also available that include these methods as part of RBI calculations.

Since the degradation increases with time, the development of degradation can be measured by inspection, thus the inspection results can be used to adjust the rate model to suit the actual situation.

5.5.4 Susceptibility model

The damage of components described by the susceptibility model is triggered by an external event after a dormant period of an unknown duration. Once triggered, the damage occurs very quickly. This model gives a fixed value for PoF depending on factors relating to the operating conditions. For a given set of conditions that are constant over time, the PoF also remains constant over time.

Since the mechanism is such that the damage can be triggered at any time and then proceed rapidly, the onset and development of the damage are difficult to monitor with inspection. However, it is beneficial to monitor key process parameters, such as excursions or a change of conditions that can trigger degradation.

5.5.5 Steps in modelling degradation

The damage models for the degradation mechanisms given in this section follow the process given below. The same basic steps should be used if alternative models or other degradation mechanisms are applied in the RBI analysis:

1) Assess which mechanism is expected in a given case.
2) Determine damage rate and failure probability:
   - Time dependent mechanisms require a distribution type with a mean value, and a standard deviation or equivalent. PoF is derived from the rate and structural reliability calculations.
   - Susceptibility mechanisms do not have a rate, but PoF is derived based on engineering judgement directly from key parameters.
3) Determine damage morphology. Three types are defined:
   - Local: localised damage that does not interfere with the load bearing capacity of the equipment wall. Failure refers to a small leak at a wall penetration.
   - Uniform: damage of such a large area that it affects the load bearing capacity of the equipment wall. Failure refers to the state when the wall ligament cannot accommodate the loading as calculated using structural reliability analyses. Typically it results in a large release.
   - Cracking: a crack that penetrates the wall. A virtual crack is assigned a single size and checked for 'leak before break', giving leak or rupture failure.
4) Define hole sizes expected on failure:
   - Expected hole sizes at failure for each degradation mechanism are stipulated in accordance with a standard hole size distribution template.

5.6 External damage

External damage is related to the external environment and condition of the surface protection. The damage rate can either be of the type 'insignificant', 'unknown', 'rate' or 'susceptibility', and is evaluated independently of any internal degradation and damage. It applies to all metallic materials with or without coating or insulation.

5.6.1 External corrosion — uninsulated

The external degradation models allow PoF calculations for different materials on the assumption that they are exposed to a marine atmosphere, or are expected to be wetted by seawater, e.g. a deluge system. Seawater may also collect on pipe supports and clamps and similar locations, promoting corrosion damage on uninsulated piping.

5.6.2 External corrosion — coated

The corrosion rate may be reduced by applying coating on the surface. The effectiveness of the coating can be assumed to be nearly perfect during the initial period, and thereafter it decreases. The deterioration pattern depends upon the coating system and maintenance. The details regarding the coating specifications and coating condition should be obtained from the specific site. In case the details about the coating are not available, then it should be conservatively treated as if the coating is not present.

In general, coatings applied in accordance with acknowledged standards and good workmanship within its area of application is expected to give full protection in a period of minimum five years and no protection after a certain amount of years after that. This lifetime might vary dependent on elements such as type of coating, local environment, condition during application and workmanship. Guidelines on coating lifetime can be found in ISO 12944, NORSOK M-501 and DNV-RP-G109. As a general guidance full coating protection from an acknowledged coating system can be expected to last 5 to 15 years provided good workmanship and coating used within its application limits.

When there is reduced coating protection, less than 100% protection, the formula for atmospheric corrosion rate as a function of temperature should be applied, see Table 5-7 to assess the PoF.

5.6.3 External corrosion — insulated

Surfaces under insulation are not readily available for visual inspection, and if water penetrates the weather protection, salt can accumulate on the metal surface possibly leading to severe local corrosion.

In order to assess external damage under insulation or corrosion under insulation (CUI) the details about the insulation and the conditions of assessment shall be collected before the assessment is carried out. As a general guideline:

— It is conservative to assume that all fibre-based insulation is water-retaining, and damaged sufficiently to allow water penetration, irrespective of what outer protection is specified.
— Personnel protection insulation may consist of a wire mesh used to prevent physical contact with hot pipes and will not retain water, and the above assumption for fibre-based insulation will be unnecessarily conservative.
— Passive fire protective coating would not normally be expected to retain water if it is in good condition. If it is cracked and otherwise poorly maintained, water retention is possible.

The external corrosion of insulated piping is modelled in a qualitative manner with four (4) barriers, see Figure 5-2 for illustration of the model. Each barrier is assessed individually. The four barriers are:

1) Material barrier: the material used in the pipe, tank or pressure vessel, and its corrosion resistance in the relevant condition. The most essential condition in this context is temperature.

2) Coating barrier: the protection of the material against the external environment. In this context, the protection is often a coating system, and the environment causing CUI is water and corrosive contamination.
3) Water wetting barrier: the extent of preventing water wetting on the equipment surface, which is determined by claddings ability to restrict the water entering the insulation, the insulation's ability to hold water, and the effect of drainage and evaporation from the insulation system.
4) Design barrier: CUI challenges may be reduced or increased based on the design of the system. Parameters such as wall thickness and pipe diameters will influence the probability of failure due to CUI. NDT results can be used to confirm wall thickness and thereby give impact on the quantitative evaluation of the design barrier.

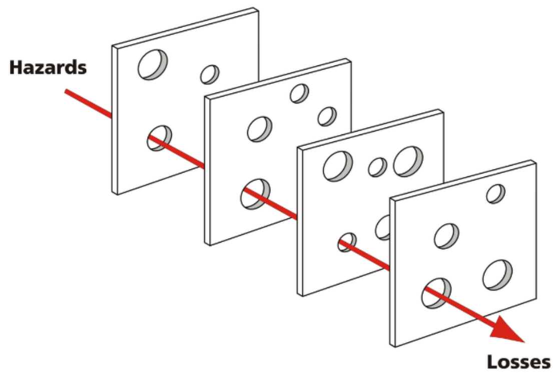

Figure 5-2 CUI barrier illustration

An extensive description of the methodology for assessing CUI is given in DNV-RP-G109.

The model described in DNV-RP-G109 combines individual qualitative probability assessments of the four CUI barriers into a total probability of failure category and combines it with the consequence of failure to create a CUI risk category:

$$PoF_{CUI} = f\ (PoF_{material}, PoF_{coating}, PoF_{water\ wetting}, PoF_{design})$$

$$Risk_{CUI} = f\ (PoF_{CUI}, CoF)$$

where:

PoF_{CUI}	=	probability of failure due to CUI
$PoF_{material}$	=	probability of breach of the material barrier as a function f temperature
$PoF_{coating}$	=	probability of failure of the coating barrier
$PoF_{water\ wetting}$	=	probability of failure for the water wetting barrier to avoid water on pipe surface
PoF_{design}	=	probability of failure of the design barrier as a function of wall thickness and geometry
$Risk_{CUI}$	=	risk for breach of the containment due to CUI.

Likely areas for CUI may be found by external visual inspection of the insulation where water can penetrate, such as faulty caulking or damaged cladding. CUI may be detected by visual examination of the pipe surface after removal of the insulation. Radiographic examination can be used to view the pipe wall profile through the insulation, thereby obviating its removal and reinstatement. A coating under the insulation will reduce the probability of attack, but the deterioration of the coating over time shall be considered. The quality and condition of coating and insulation work shall be assessed from case to case. Strategies for corrosion control under insulation will depend upon the condition and maintenance of coating and insulation. Further information can be found in DNV-RP-G109 and EFC 55.

5.6.4 Steps in modeling external degradation

The calculation of external degradation is done by the following steps:

1) Define the material type as given in Table 5-1.
2) Determine the operating conditions applicable to the part under consideration. Take into account temperature and pressure and condition of coating.
3) Go to the relevant sections to calculate the degradation rate or PoF as applicable.

5.7 Internal damage

This section discusses some of the most relevant services, materials and degradation mechanisms for internal damage. The discussion is based on general knowledge gathered from operating companies and open literature. All combinations of materials and services have not been covered, and expert evaluations may be needed where these are missing.

Internal damage mechanisms are based on combinations of material of construction, operating conditions and fluids flowing in the pipe. As a guideline, the product service codes used on offshore topside systems can give an indication of the type of fluid that can be expected to flow in the pipe.

5.7.1 Product service code definition

The objective of the product service codes is to aid in determining the possible degradation mechanisms for the component under consideration. Assessment of the possible degradation mechanisms is based on general experience and fundamental knowledge of materials and service. The outcome of the assessment is a conservative listing of components with their possible degradation mechanisms. Table 5-5 lists the two character product service codes and the contents that are assumed as the basis for internal degradation models.

Often product service codes different from those listed in Table 5-5 will be encountered while assessing installations. For such conditions it is important that installation-specific codes be checked and matched to the descriptions given in the table. Incorrect evaluations of the degradation mechanisms may occur if the fluids do not conform exactly to the descriptions given in the table. Specialist advice should be sought if there are discrepancies.

Although the product service codes are used to determine the expected internal degradation mechanism, it is a simplification, and the limitations must be recognised and accounted for in each analysis:

- The product service code does not always provide sufficient differentiation with respect to fluid corrosiveness. It is necessary to review the system and split it into more detailed areas, e.g. to identify where hydrocarbon gas is dry and wet.
- The product service code may not reflect some operational practices, e.g. closed drains may be used as a bypass system.
- The product service code may not reflect content, e.g. closed drains may be used as a bypass system.
- Some of the product service codes are so unspecific or variable that the contents must be assessed by suitably qualified personnel.
- The materials listed are intended to give general and conservative results. The calculations can be improved if more precise material specifications are used.
- The models have limits on their applicability, and it should be verified that the model is applicable to the situation at hand. In all cases, there is an upper temperature limit of 150°C.
- Where the conditions given in this appendix do not match with those found in the plant, specialist advice must be sought.

Table 5-5 Product service code with descriptions and degradation mechanism group

Product service code	*Description*	*Degradation group*
AI	Air instrument Compressed air system for pneumatic controllers and valve actuators and purging of electrical motors and panels. Comprises dry, inert gas.	Insignificant
AP	Air plant Compressed air system for air hoists/winches, air motors, sand blasting, spray painting, air tools and motor purging. Typically not dried, so parts may contain water vapour and condensation. Condensed water can be considered fresh.	Waters
BC	Bulk cement Cement powder, generally in dry form.	Chemicals
BL	Cement liquid additive May be proprietary liquids. Plasticisers, accelerators and retarders added as liquid to liquid cement to adjust the flow and curing characteristics.	Chemicals
CA	Chemical, methanol Used to prevent and dissolve hydrates in water containing hydrocarbon gas systems. Should contain less than 2% water by volume. May be used as water scavenger.	Insignificant
CB	Chemical, biocide May be proprietary fluid biocide such as glutaraldehyde, or chlorine from e.g. electrolysis of seawater or from addition of sodium hypochlorite, etc.	Chemicals
CC	Chemical, catalyst May be proprietary fluid catalyst for chemical reaction control.	Chemicals
CD	Chemical, scale inhibitor May be proprietary scale inhibitor used to prevent scale problems arising from $BaSO_4$, typically downhole, and $CaCO_3$, typically surfaces and heaters.	Chemicals
CE	Chemical, demulsifier or defoamant May be proprietary fluid defoamant / emulsion breaker for water content control in oil by aiding separation of oil and water.	Chemicals
CF	Chemical, surface active fluid May be proprietary fluid surfactant with dual hydrocarbon and polar character and dissolves partly in hydrocarbon and partly in aqueous phases.	Chemicals
CG	Chemical, glycol 100% glycol, which is not considered corrosive.	Insignificant
CH	Chemical, aqueous film-forming foam (AFFF) Fire fighting foam additive to firewater.	Insignificant
CJ	pH controller May be proprietary chemical for buffers, typically to raise the pH.	Chemicals
CK	Corrosion inhibitor May be proprietary fluid for injection as corrosion protection. Usually not corrosive in undiluted concentration.	Insignificant

Product service code	*Description*	*Degradation group*
CM	Cement high/low pressure Cement mixed with a carrier, usually seawater, and used downhole. Likely to be erosive.	Chemicals
CN	Chemical, mud additive Typically mud acids, e.g. HCl, HF.	Chemicals
CO	Chemical, oxygen scavenger Oxygen scavenger, typically sodium bisulphite, Na_2S. Corrosiveness depends on type, and possibly concentration and temperature. Moderate to low concentrations can be tolerated in a variety of materials, but high concentrations may be corrosive.	Chemicals
CP	Chemical, polyelectrolyte/flocculent May be proprietary fluid flocculent for oil content control in produced water.	Chemicals
CS	Chemical, sodium hypochlorite solution Concentrated NaClO for supply to each consumer. Corrosiveness depends on concentration and temperature.	Chemicals
CV	Chemical, wax inhibitor May be proprietary wax inhibitor for use in produced liquids to hinder formation of waxes as temperatures are reduced.	Chemicals
CW	Chemical, glycol/water, rich glycol to regenerator. Regeneration system to remove water from glycol/water. Part of the gas drying system. The system is in contact with hydrocarbons. The area in contact with hydrocarbons, and the rich part of the regenerator, is likely to be the most corrosive area of the system. System fluids are regularly checked for pH due to glycol breakdown. Note: lean glycol corrosiveness is dependent on water content and composition.	Chemicals
DC	Closed drain system Hydrocarbon liquids in drains from platform equipment and piping, collected in a closed vessel. Intermittent use or low flow rates leading to stagnation. May have fuel gas blanket at low pressure. Liquids comprise hydrocarbon oil, gas, water, in proportions according to the equipment drained. There is potential for microbial action.	Hydrocarbons
DO	Drain, open Drain from helideck, roof drain and drain from test lines, etc. Mostly seawater and rainwater, but some oil likely. Under atmospheric pressure.	Waters
DS	Drain, sewer/sanitary Closed system. Drain from living quarters containing domestic sewage.	Waters
DW	Drain water/storm Open system. Accumulated water from sea spray and rain led to floor gullies.	Waters
FC	Completion fluid high/low pressure	Chemicals
FJ	Fuel, jet Clean, water-free aviation fuel, i.e. kerosene, for helicopters.	Insignificant

Product service code	*Description*	*Degradation group*
GA	Gas, firefighting/CO_2 Dry, typically bottled, CO_2 used as extinguishing gas.	Insignificant
GF	Gas, fuel Process gas used to fuel compressors and generators. Dried hydrocarbon gas with CO_2 and H_2S in the same quantities as the process system.	Insignificant
GI	Gas, inert Inert gas, such as nitrogen or dry CO_2. Note: some installations use exhaust gas for blanketing storage tanks with this product service code, and these should be considered as cold exhaust gas.	Insignificant
GW	Gas, waste/fuel Products of burning hydrocarbon gas or diesel fuel. Acidic combustion products may condense in exhaust piping causing high corrosion rates.	Vents
MB	Mud, bulk/solid Storage of mud components prior to mixing.	Chemicals
MH	Mud, high pressure High pressure mud pumping system for deliverance of drilling and completion fluids in normal use. May contain well intervention fluids, completion and packer brine fluids, mud acids, e.g. HCl, HF, well stimulation fluids, scale inhibitors, methanol, diesel, varying densities of byrites or other solids.	Chemicals
MK	Mud, kill Mud pumped into the well for well control purposes. May contain heavy densities of byrites or other solids.	Chemicals
ML	Mud, low pressure As MH.	Chemicals
OF	Oil, fuel, e.g. diesel oil Diesel fuel for use in cranes, generators and well pressure equalisation. Usually dry, but may contain water and organic matter that settles in low/stagnant points.	Insignificant
OH	Oil, hydraulic Clean, dry, filtered hydraulic oil for actuators.	Insignificant
OL	Oil, lubricating Clean, dry, filtered oil for lubrication purposes.	Insignificant
OS	Oil, seal Clean, dry, filtered seal oil for gas compressors. May contain amounts of dissolved process gas.	Insignificant
PB	Process blow-down Wet hydrocarbon gas. Parts of system are vents and flare. Will contain CO_2 and H_2S in the same proportions as the systems blown down. Normally purged with fuel gas at low pressure.	Hydrocarbons

Product service code	*Description*	*Degradation group*
PL	Process hydrocarbons, liquid Untreated liquid hydrocarbons, post inlet separator. Contains some gas but mostly hydrocarbon liquid with some water, dissolved CO_2 and H_2S, potential for sand. May also contain small amounts of CO_2 corrosion inhibitor, scale inhibitor, emulsion breaker and other chemicals. Water contains high levels of dissolved salts from the reservoir. If water injection is part of the process, it may contain bacteria that can colonise in stagnant areas.	Hydrocarbons
PS	Process hydrocarbons, vapour wet Wet untreated gas where water vapour is expected to condense into liquid. Contains CO_2 and H_2S in the same proportions as the reservoir.	Hydrocarbons
PT	Process hydrocarbons, two phase Untreated two phase flow upstream of inlet separator. Contains oil, gas, water, sand, and also CO_2 and H_2S in the same proportions as the reservoir. May also have inhibitor and stabilisation chemicals injected close to the wellhead. If water injection is part of the process, it may contain bacteria that can colonise in stagnant areas.	Hydrocarbons
PV	Process hydrocarbons, vapour Dry hydrocarbon gas where water is not expected to condense as liquid, post separator. Contains CO_2 and H_2S in the same proportions as the reservoir.	Hydrocarbons
PW	Produced water system Water from the production separators. It contains water with dissolved CO_2 and H_2S in the same proportions as the reservoir, and some oil. Sand may be carried over from the separator.	Hydrocarbons
SP	Steam, process	Not included *)
SU	Steam, utility/plant	Not included *)
VA	Vent, atmospheric	Vents
VF	Vent, flare	Vents
WA	Water, sea anti-liquefaction	Waters
WB	Water, sea ballast/grout Oxygen rich seawater that may be treated with biocide/chlorination.	Waters
WC	Water, fresh/glycol cooling medium A closed system where direct seawater cooling is not applicable. Fresh or desalinated water treated with triethylene glycol (TEG), regularly checked for low pH arising from breakdown of the TEG.	Waters
WD	Water, fresh potable Oxygen rich, chlorinated fresh water often with small amounts of salts added for palatability. The max Cl^- ion concentration is 200 ppm.	Waters
WF	Water, sea firefighting Closed seawater system treated with biocides/chlorination.	Waters
WG	Water, grouting systems Used for the make up of cementitious grout during installation or drilling operations. May be either raw seawater or desalinated seawater.	Waters

Product service code	*Description*	*Degradation group*
WH	Water, fresh/glycol, TEG, heating medium Heating medium providing required heat load to process and utility equipment. Fresh or desalinated water mixed with TEG. May also contain corrosion inhibitor. Regularly checked for pH due to breakdown of the TEG.	Waters
WI	Water, injection Injected water used for enhanced reservoir recovery. May be treated produced water, treated seawater, or a combination.	Water injection
WJ	Water, jet Jet water supply for removing sand from separators, cleaning of tanks etc. May be supplied from produced water, fresh water, disinfected, or treated seawater. May also require addition of anti-scale chemicals.	Waters
WP	Water, fresh, raw Desalinated, oxygen rich, untreated water.	Waters
WQ	Water, fresh, hot. In a closed circuit. Fresh or desalinated, oxygen rich, untreated hot water for living quarter and equivalent.	Waters
WS	Water, sea Oxygen rich seawater for distribution to the various platform users. May be treated with chlorination to prevent biological growth within the system.	Waters
*) Steam, SP and SU, are expected to have a normal operating temperature > 150°C.		

Table 5-6 Water categories, definition and description

Water categories	*Description*
Raw seawater	Seawater: untreated, normal oxygen, bacteria, marine flora, etc.
Seawater + biocide/chlorination	Seawater: treated with UV/filtered or bactericide, chlorinated.
Seawater low oxygen	Seawater: deoxygenated, max. 50 ppb O_2. No other treatment.
Seawater low oxygen + biocide	Seawater: deoxygenated, max. 50 ppb O_2, treated with UV/filtered or bactericide. No chlorination.
Seawater low oxygen + chlorination	Seawater: deoxygenated, max. 50 ppb O_2 and chlorinated.
Seawater low oxygen + biocide + chlorination	Seawater: deoxygenated, max. 50 ppb O_2, treated with UV/filtered or bactericide, chlorinated.
Fresh water	Desalinated water: typically prepared by condensation of seawater. Basis for plant water for e.g. steam generation, low salt content, normal oxygen.
Closed loop	Closed loop systems: desalinated systems that have intrinsically lowoxygen content.
Exposed drains	Seawater: open systems that collect water from drains, sluices, deluge, etc., and are assumed to contain untreated, raw, seawater.
Sanitary drains	Fresh water: drains from sanitary systems. Fresh water with high bacteria and organic matter content.

5.7.2 Internal degradation mechanism — sand erosion

Degradation due to sand erosion gives general wall thinning where the product flow impinges on the pipe or vessel wall, such as at changes in flow direction, or areas where obstructions cause eddying, such as at valves or orifice plates. The rate of wall loss by erosion increases with the quantity of sand in the product and the product flow rate. Detection and estimation of sand rate can be by acoustic monitoring, the examination of coupons, or the frequency of separator jetting. Inspection for the presence of erosion can be by internal visual, external ultrasonic or radiographic examination of the internal surface where allowed by access and geometry.

5.7.3 Internal degradation mechanism — water systems

Water systems use 'water' of varying corrosiveness, ranging from untreated seawater to potable water. The product service codes for the water-containing systems are not sufficient to define the water type with respect to corrosiveness, and do not account for changes that can occur during processing. E.g. in a system, 'raw seawater' after treatment can become 'fresh water'.

A number of water categories that are commonly encountered on offshore installations have been defined, as given in Table 5-6. It is necessary to determine the best match between a water category and the product service code used in each water system, or part of a system. Screening discussions with reference to process drawings can help establish the best match.

Appropriate corrosion mechanisms have been assigned for each of the water categories. These include:

— Uniform corrosion: assumed in carbon steels, and the PoF is derived from the wall thinning rate.
— Local corrosion: pitting and crevice corrosion that is expected in stainless steels in oxygenated waters. These degradation mechanisms return a PoF based on susceptibility that is constant over time for given operational parameters.
— Microbial corrosion: also called microbiologically influenced corrosion (MIC) in waters, takes place where organic life can be sustained and no effective biocides are used.

Note that:

— Produced water is included in the hydrocarbon systems.
— Water injection systems use various types of treatment, and shall be considered on a case to case basis.

5.7.4 Internal degradation mechanism — microbiologically influenced corrosion

Bacterial growth in the presence of water and nutrients gives rise to MIC, causing pits on internal surfaces of carbon steel piping/equipment due to the formation of biofilms or semi-solid deposits at the metal surface. In general, MIC can result in localized corrosion under four basic conditions:

1) presence of free water in contact with the metal surface
2) optimal microbiological growth conditions, temperature and pH
3) availability of nutrients
4) stagnant or low fluid flow.

See App.B for guidance on how to evaluate and determine the PoF due to MIC.

MIC pits may be widely spaced within a system, so detection of damage is difficult, unless high coverage inspection is used. Inspection of these pits will require extensive ultrasonic, radiographic or internal visual inspection. It is generally advisable to start by monitoring for the presence of microbes through bacteria sampling, e.g. by visual investigation of filters and stagnant bottom sludges. More detailed analysis should address the location of biocide injection points and effectiveness of the biocide. The detection of MIC in one part of a system strongly suggests that it will be present in similar systems on the installation.

5.7.5 Internal degradation mechanism — hydrocarbon systems

The multiphase hydrocarbon-water-gas systems, like produced water and closed drains, shall be evaluated with respect to the presence of the hydrocarbons along with corrosion and cracking respectively due to the dissolution of CO_2 and H_2S, in water. In some circumstances, microbial corrosion can also occur. Additionally, any sand that is entrained in the system can cause sand erosion where the flow impinges on the pipe or equipment surface.

The presence and composition of water varies through the processing train, hence the product service codes have limited value in guiding expected degradation. It is thus necessary to study the process flow to identify, split and group equipment with similar environmental and operational conditions. The following points should also be considered:

— Chemical treatment, e.g. inhibition, is commonly used to limit CO_2 corrosion in carbon steel, and injection points and inhibitor performance shall be evaluated.
— Hydrocarbon production processes are expected to change over time and these shall be considered when planning inspection, e.g. lower pressure, water breakthrough.
— Hydrocarbon systems usually employ various types of corrosion monitoring and have traditionally received high inspection focus. Service data, e.g. condition, integrity and process data, may be available for installations that have been in service, and these data should be evaluated and used together with the models given here.

Expected damage can be calculated for various degradation mechanisms using the following factors for guidance:

— Assess the presence of water and its composition and pH.
— Assess the equivalent partial pressure of CO_2 and H_2S gases in a water phase.
— Assess the possible presence and effects of MIC.
— Determine the PoF due to hydrogen pressure induced cracking (HPIC) or stress oriented hydrogen induced cracking (SOHIC) due to the presence of H_2S.
— Determine the PoF due to sulfide stress cracking (SSC).
— Determine the PoF due to CO_2 corrosion.

— Assess the effects of chemical treatments, internal organic coatings and cathodic protection.
— Determine the PoF due to sand erosion.

5.7.6 Internal degradation mechanism — chemicals

Chemicals can be split into three groups:

— Proprietary chemicals: these include, but are not limited to, corrosion inhibitors, flocculants, bactericides.
— Drilling chemicals: these are of limited interest on a production installation.
— Identifiable chemicals: these are common chemicals, but their corrosiveness is dependent on the concentration and temperature.

The first two groups may have chemicals given by trade names only. In many cases they may be non-corrosive and innocuous in service conditions. In other cases, particularly at high concentrations, they can be highly corrosive or toxic.

The third group includes chemicals that have more readily available corrosion data, although the possible variation in type and concentration implies that corrosiveness must be evaluated on a case by case basis. The systems containing these chemicals should typically be discussed during the screening. The consequence is expected to be low in most cases and many components can be expected to be screened out without further effort required.

It is common that chemical systems can be assessed as either 'insignificant' or 'unknown' systems as discussed earlier.

5.7.7 Internal degradation mechanism — vent systems

The vent system collects the vapour phase from various parts of the process. Each part of the vent system shall be evaluated with respect to what is being vented. Generally, the vent lines will be subject to the same degradation mechanisms as the vapour phase in the equipment being vented.

Vent system equipment, such as knock-out drums, may collect vapours from several areas, and should be considered with respect to the composition of any liquid phases that they may collect.

5.7.8 Internal degradation mechanism — water injection systems

Water injection systems usually use large volumes of treated water, such as seawater, produced water, or a combination of these. Treatment typically includes deoxygenation/deaeration, chlorination or similar biocide, pH buffering, and anti-scaling. Significant amounts of CO_2 may be dissolved in the water. High injection rates imply that damage related to flow can arise. A variety of materials are deployed in water injection systems, and correct treatment, relative to the materials, is essential. It is recommended that water injection systems be addressed on a case for case basis. However, in many cases, the water injection system can be evaluated as equivalent to a water system or produced water.

5.7.9 Steps in modelling internal degradation mechanism

The user is advised to ensure that the conditions on the asset match those listed in the section before using the models. A specialist should be referred to for advice on deviations.

The PoF calculation due to internal degradation follows the process below:

1) Define the material type, as given in Table 5-1.
2) Define the appropriate product service code and identify the potentially corrosive contents. See Table 5-5.
3) Determine the service conditions applicable to the part in question, comprising temperatures, pressures, amounts of corrosive species.
4) Go to the relevant sections, [5.8] to [5.12], and calculate the degradation rate or PoF as applicable.

5.8 Carbon steel

5.8.1 External corrosion of carbon steel piping

Carbon steels suffer marked external corrosion, but to mitigate the problem they are usually protected by a coating.

5.8.1.1 External corrosion of uninsulated carbon steel piping

External corrosion of uninsulated carbon steel piping is due to exposure to marine atmosphere. The corrosion rate increases with temperature and with coating breakdown. The external corrosion rate of uninsulated and uncoated carbon steel piping is a function of temperature and is modelled as a normal distribution characterised by the mean and standard deviation as given in Table 5-7.

The external corrosion of uninsulated carbon steel piping is assumed to result in uniform wall thinning occurring in areas or patches. It can lead to bursts at the thinnest part of the patch when the local stress exceeds the material's strength. The leak holes generated are normally small and usually occur in connection with a patch. The hole size distribution of the piping containing leak holes is given in Table 5-8.

Inspection for atmospheric corrosion can be done by external visual inspection, concentrating on areas where weathering is most likely or where water can collect, such as under clamps.

Table 5-7 External corrosion rates of uninsulated carbon steel piping

Temperature [T] range [°C]	*Mean [mm/year]*	*Standard deviation [mm/year]*	*Notes*
$T < -5°C$	Not applicable	Not applicable	PoF = 10^{-5}
$-5°C < T < 20°C$	0.1	0.05	-
$20°C < T < 100°C$	$0.3547 \times \ln(T)-0.9334$	$0.3929 \times \ln(T) -1.0093$	-
$100°C < T$	-	-	Surface drying occurs and will affect the corrosion rate. Refer to a specialist.

Table 5-8 Hole size distribution due to external corrosion of uninsulated carbon steel piping

Equivalent hole diameter	*% distribution*
Small hole	90
Medium hole	9
Large hole	1
Rupture	0

5.8.1.2 External corrosion of insulated carbon steel piping

The external corrosion of insulated carbon steel piping occurs when the insulation traps moisture in its porous structure and attacks the external wall of the piping, resulting in external uniform or local corrosion defects. The mechanism is referred to as CUI. The rate of corrosion increases with increased exposure to water and increase in temperature. Above $100^{o}C$ the wet insulation will dry out, but in the process it will concentrate salts, which will result in accelerated corrosion rates while the temperature is rising. Subsequent cooling will also result in rapid corrosion due to rehydration of the deposited salts.

CUI on carbon steel piping is managed according to the methodology described in [5.6.3] and in detail in DNV-RP-G109. If a corrosion rate for CUI shall be calculated the models given in Table 5-9 may be utilised. The corrosion rate for CUI is modelled as a normal distribution with mean and standard deviation, on the assumption that saltwater is present on the bare metal surface, i.e. no coating is present or coating is degraded. If the insulation is dry, the model does not apply.

Table 5-9 External corrosion rates for insulated carbon steel piping

Temperature [T] range	*Mean [mm/year]*	*Standard deviation [mm/year]*	*Notes*
$T < -5°C$	-	-	PoF = 10^{-5}
$-5°C < T < 20°C$	As 20°C	0.286	May overestimate rate, but failures found at low temperatures.
$20°C < T < 100°C$	$0.0067 \times T + 0.3000$	0.286	
$100°C < T$			Refer to a specialist.

CUI is expected to occur in patches where conducive conditions occur. The damage is not expected to interfere significantly with wall stresses and a leak, rather than a burst, is expected. For CoF assessment, the hole sizes are expected as given in Table 5-10.

Table 5-10 Hole size distribution due to external corrosion of insulated carbon steel piping

Equivalent hole diameter	*% distribution*
Small hole	80
Medium hole	20
Large hole	0
Rupture	0

5.8.2 Internal corrosion of carbon steel

5.8.2.1 Internal corrosion of carbon steel piping — erosion

The rate of erosion can be modelled as a normal distribution. The mean of the distribution can be calculated according to the model given in DNV-RP-O501 and 0.20 is used as the coefficient of variance (CoV).

The damage morphology is a 'uniform' type and the hole size distribution is given in Table 5-11.

Table 5-11 Hole size distribution in carbon steel piping internally degraded by erosion

Equivalent hole diameter	*% distribution*
Small hole	0
Medium hole	0
Large hole	0
Rupture	100

5.8.2.2 Internal corrosion of carbon steel piping — water

The internal corrosion of carbon steel piping due to water includes corrosion due to different categories of water, as defined in Table 5-6. Corrosion rates increase with an increase in flow rate, oxygen concentration and temperature. The rates are also applicable to carbon steel where an organic coating is damaged. TEG use at concentrations of 30% in closed systems is effective in reducing corrosion to very low rates. Inspection can be done by external radiography or ultrasonics to measure wall loss.

The rate of internal corrosion of carbon steel piping due to water can be modelled by normal distribution defined by mean and standard deviation. Table 5-12 gives the corrosion rates by water type and flow conditions.

The corrosion due to water results in uniform wall thinning, but this may become localised if internal scales form and break down in patches. The hole size distribution is given in Table 5-13.

Table 5-12 Corrosion rates in carbon steel piping by different categories of water

Material type	*Mean [mm/year]*	*Standard deviation [mm/year]*
Raw seawater	Flow dependent: rates from Figure 5-3.	0.1
Seawater + biocide/chlorination	Flow dependent: rates from Figure 5-3.	0.1
Seawater low oxygen	0.01	0.01
Seawater low oxygen + biocide	0.01	0.01
Seawater low oxygen + chlorination	0.01	0.01
Seawater low oxygen + biocide + chlorination	0.01	0.01
Fresh water, Cl less than 200 ppm	0.25	0.1
Closed loop	0.01	0.01
Exposed drains	Flow dependent: Rates from Figure 5-3.	0.1
Sanitary drains	Treat as MIC. Rates from App.B .	0.1

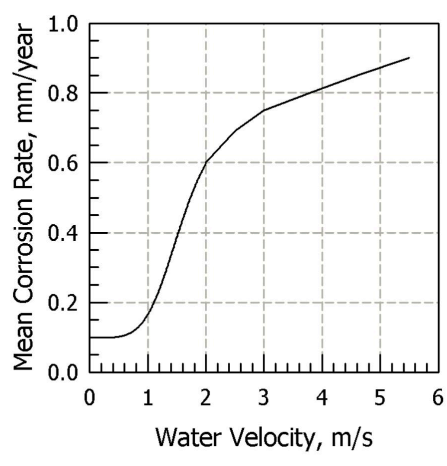

Figure 5-3 Carbon steel corrosion rate variation with flow rate of sea water

Table 5-13 Hole size distribution in carbon steel piping internally degraded by aqueous corrosion

Equivalent hole diameter	*% distribution*
Small hole	0
Medium hole	0
Large hole	100
Rupture	0

For a list of subjects that should be evaluated in relation to internal corrosion of carbons steel piping in water systems, see Table 5-14

Table 5-14 Notes regarding internal corrosion of carbon steel piping in water systems

Consideration	*Notes*
Galvanised steel/zinc	Internal galvanisation is rarely effective in long-term corrosion control, and so no credit should be given to galvanised steel: it is treated as carbon steel. Beware clogging of nozzles due to zinc corrosion products.
Cement linings	No credit should be given for these linings: it is treated as carbon steel. Inspection should include procedures for examining the condition of the lining.
Organic linings	Organic linings should be identified. Their performance should be estimated on a case by case basis. A degradation profile may be defined and applied to the corrosion rates given in this document. A procedure for defining a degradation profile is given in external corrosion models.
Cathodic protection	The theoretical performance of sacrificial anode systems can be checked by reference to procedures such as NORSOK and DNV-RP-B401, while monitoring/inspecting the anode consumption should give a good indication of their effectiveness in practice. Note that anodes should be placed so they lie in the water phase to be effective.
Galvanic corrosion	Galvanic corrosion may occur with certain material combinations, typically between carbon steel and stainless steel. The extent of damage is dependent on the relative areas of the materials, and the resistivity of the media. In some cases galvanic corrosion is advantageous, e.g. where pumps and valves with lower grade stainless steel housings are used in carbon steel pipework: the stainless steel will be 'protected' by the carbon steel. In other cases, e.g. where there is a large cathodic area, high corrosion rates can be expected. Correct assignment of anode and cathode for many common material combinations is strongly affected by local conditions, thus any changes in materials should be identified and referred to a specialist for evaluation.
Welds	Corrosion of welds in carbon steel water bearing systems is variable. All or part of the weldment may be attacked. Initial inspection should target welds and parent materials. Inspection findings can be reviewed to determine where future inspections can be focused. Data from online monitoring, e.g. corrosion probes, iron counts, should be used with caution, preferably as a supplement to some inspection.

5.8.2.3 Internal corrosion of carbon steel piping — microbiologically influenced corrosion

Microbial corrosion is generally not expected in other materials than carbon steel. For a detailed guidance on where inspections should be carried out due to the threat of MIC by assessing the PoF and establishing a MIC management strategy, see App.B.

The damage morphology due to microbial corrosion is 'leak' and the hole size distribution is given in Table 5-15.

Table 5-15 Hole size distribution in carbon steel piping internally degraded by microbiologically influenced corrosion

Equivalent hole diameter	*% distribution*
Small hole	90
Medium hole	10
Large hole	0
Rupture	0

5.8.2.4 Internal corrosion of carbon steel piping — CO_2 corrosion

CO_2 corrosion of carbon steel piping takes place in the presence of the gas-water-hydrocarbon multiphase system. It is associated with the water phase, and is therefore likely to be located where water is consistently in contact with the metal surface. Such areas are around the 6 o'clock position in piping. However, CO_2 corrosion may also be seen around the 12 o'clock position where uninhibited water vapour condenses on the metal surface. The corrosion is also likely in dead legs and other water traps, including irregularities at welds. Complete dehydration prevents CO_2 corrosion.

CO_2 corrosion rate increases with an increase in the CO_2 content. expressed as mol% or vol% in the gas phase, and total pressure. It decreases with an increase in pH and effectiveness of corrosion inhibitor. E,g,, methanol injection can have an inhibition effect. It can either increase or decrease with temperature, depending on the temperature and the presence or absence of protective scales. Corrosion inhibitor failure can often be tolerated for short periods, but extended lack of inhibition may give rise to extensive degradation.

Coupons can be used to detect corrosion and monitor inhibitor effectiveness. While carrying out a coupon study, consideration shall be given to their location with reference to water content. Rate measurement and inspection can be done by internal visual or external ultrasonic examination for areas of uniform thinning and internal visual, extensive external ultrasonic or radiographic examination of the internal surface for local wall loss. In all cases, it is essential that hot spots be identified.

Due to the CO_2 corrosion, both 'local' and 'uniform' damage can take place. 'Uniform' refers to larger areas of damage, typically at the 6 o'clock position. For calculating the rate of corrosion, NORSOK M-506, (de Waard, 1993), (de Waard, 1975), (de Waard, 1991), or similar can be used.

For assessing the rate of 'local' corrosion, use the calculated mean value from the CO_2 corrosion rate predictive model as the mean rate, with a CoV of 0.45 in a Weibull distribution.

For assessing the rate of 'uniform' corrosion, use 0.4 multiplied by the calculated mean value from the CO_2 corrosion rate predictive model as the mean rate, with a CoV of 0.8 in a Weibull distribution.

The chemical inhibitor effectiveness should preferably be modelled as a probabilistic distribution, e.g. as a Weibull distribution with nominal efficiency as the mean and the CoV based on an evaluation of the performance in service. As a simplification, the nominal inhibitor factor can be used to reduce the mean corrosion rate used in the Weibull distributions given above.

The hole size distribution due to the degradation by CO_2 corrosion is given in Table 5-16.

Table 5-16 Hole size distribution in carbon steel piping internally degraded by CO_2 corrosion

Equivalent hole diameter	*% distribution*	
	Uniform corrosion	*Local corrosion*
Small hole	0	50
Medium hole	0	50
Large hole	0	0

Equivalent hole diameter	% distribution	
	Uniform corrosion	Local corrosion
Rupture	100	0

5.8.2.5 Internal corrosion of carbon steel piping — H_2S cracking

All forms of cracking due to H_2S should be prevented by correct material selection, see EFC 16, EFC 17, NACE MR0103/ISO 17495, NACE MR 0175/ISO 15156. If materials and welding are within limits set by these documents, PoF = 10^{-5}, otherwise PoF = 1.0 and detailed manual assessment will be required.

No further PoF calculations are required. Damage morphology is 'cracking'. The hole size distribution is given in Table 5-17.

Table 5-17 Hole size distribution in carbon steel piping internally degraded by H_2S

Equivalent hole diameter	% distribution	
	Stable (leak)	Unstable (burst)
Small hole	0	0
Medium hole	100	0
Large hole	0	0
Rupture	0	100

5.8.2.6 Internal corrosion of carbon steel piping - systems purged with inert gas

Hydrocarbon systems may be continuously or temporary purged with inert gas.

Inert gas used as purge gas is mainly: nitrogen gas, which may typically contain up to 1% oxygen. Fuel gas / produced gas - hydrocarbon gas

For hydrocarbon systems purged with nitrogen gas, the gas purity is of importance. If the nitrogen contains oxygen and the hydrocarbon gas contains H_2S, elemental sulphur may readily form. Elemental sulphur is very corrosive, particular for carbon steel. The corrosion takes the form of localised attacks and the rate may be up to several mm/year. The solubility of elemental sulphur in water is very low. This means that if elemental sulphur is formed it will readily precipitate. For system with a high water content, e.g. oil reclaiming, water treatment, produced water systems, the probability of corrosion due to elemental sulphur is therefore present.

The solubility of elemental sulphur is much higher in liquid hydrocarbons than in water and will mostly be dissolved in the oil phase. The solubility increases with increasing temperature and any dissolved elemental sulphur may therefore also precipitate upon change in temperature. For systems with low water content, e.g. oil systems, the risk of corrosion due to elemental sulphur is reduced.

For evaluation of PoF due to elemental sulphur, detailed manual assessment by specialist is required.

5.9 Stainless steel

5.9.1 External corrosion of stainless steel

Stainless steels have generally good resistance to exposure in marine atmosphere and suffer only incipient corrosion, although local accumulation of salts can lead to severe corrosion, and such areas shall be focused on during inspection.

Where the stainless steel is insulated, the effect of saltwater trapped against the metal can result in pitting at moderate temperatures. At higher temperatures, stress corrosion cracking occurs in some stainless types under conducive conditions, i.e. at areas of high stress, such as welds and heavy cold work. Both local corrosion and cracking shall be considered.

5.9.1.1 External corrosion of stainless steel — uninsulated

Stainless steels generally have good resistance to atmospheric corrosion, but the presence of deposits or crevices can lead to local attack. Inspection should concentrate on identifying locations where such local attack might occur.

Table 5-18 Hole size distribution in externally corroded uninsulated stainless steel piping

Equivalent hole diameter	*% distribution*
Small hole	100
Medium hole	0
Large hole	0
Rupture	0

Uncoated stainless steels can be expected to have a PoF of 10^{-4} for one mm wall thickness. For other wall thicknesses, PoF =10^{-4}/(wall thickness). Note that the excessive presence of deposits, and water traps under clamps, labels and similar should be given special attention and may justify manual evaluation of the PoF.

The hole size distribution as given in Table 5-18 should be used.

5.9.1.2 External local corrosion of stainless steel — insulated

This mechanism presents itself on stainless steels as apparently randomly distributed pits, albeit typically more predominant at welds, and is associated with saline water retained by insulation, deposits, etc. The PoF increases markedly with temperature, depending also on the type of stainless steel. Control of temperature is thus important. Attention should also be paid to excluding water by effective waterproofing of the insulation. A coating on the steel will reduce probability of attack, but the deterioration of coating over time shall be considered. After removal of the insulation, detection can be made by visual or dye penetrant examination of the surface. Once pitting has initiated it can progress rapidly to failure. Note that this type of damage is expected to arise under similar circumstances as external stress corrosion cracking (ESCC).

CUI on stainless steel piping is managed according to the methodology described in [5.6.3] and in detail in DNV-RP-G109. If PoF for local corrosion on stainless steel shall be determined the methodology given below may be used. The onset of local corrosion on stainless steel is controlled by temperature, given that the conducive conditions are present. The PoF per unit wall thickness for the different materials is given as a function of temperature in Figure 5-4.

1) Select curve for material in Figure 5-4. Read off the PoF for a given temperature.
2) Divide the result by the wall thickness in mm, to give PoF.

Stress corrosion cracking can also occur in stainless steels at elevated temperatures. Inspection of the insulation condition itself is a very important means of controlling damage under insulation.

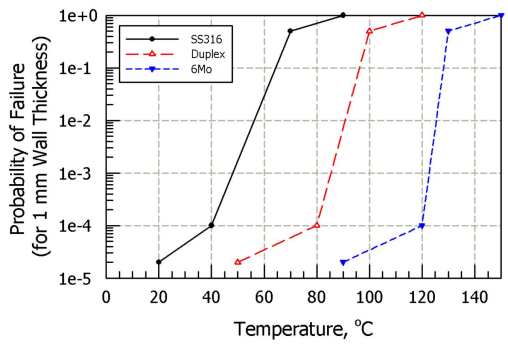

Figure 5-4 Probability of failure for local corrosion of stainless steel under insulation

The hole size distribution as is given in Table 5-19 should be used.

Table 5-19 Hole size distribution in externally and locally corroded insulated stainless steel piping

Equivalent hole diameter	*% distribution*
Small hole	100
Medium hole	0
Large hole	0
Rupture	0

5.9.1.3 External stress corrosion cracking of stainless steel

ESCC of stainless steel appears as cracking in areas with high tensile stresses, typically at welds, and is associated with saltwater retained on the material surface. The PoF due to ESCC increases markedly with temperature, but is dependent on the type of stainless steel, thus control of temperature is important. A coating on the steel will reduce probability of attack, but the deterioration of coating over time shall be considered. Detection can be made by visual external examination or NDT methods for surface cracking. Note that once ESCC has been initiated, it is expected to progress rapidly to failure, and inspection is therefore not suitable for monitoring defect development.

The onset of ESCC is controlled by temperature, given that the conducive conditions are present. The PoF for different materials is given as a function of temperature in Figure 5-5, with the hole size distribution given in Table 5-20. Note that the figure does not apply to material type 6Mo and 25Cr duplex. ISO 21457 states that ESCC may occur at elevated temperatures for 25Cr duplex and 6Mo. See ISO 21457 for applicable temperature limits. If possible, a specialist should be consulted to evaluate PoF at elevated temperatures.

Before concluding on hole size, an assessment of leak-before-break should be made. Duplex stainless steels may suffer a toughness transition when subjected to low temperatures, such as during a blowdown, which may lead to a rupture of the part. Otherwise, the high toughness generally found in stainless steels will prevent unstable fracture.

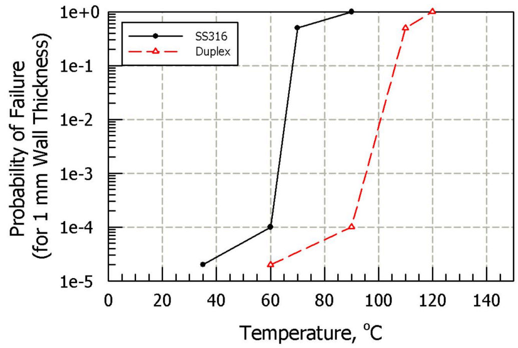

Figure 5-5 Probability of failure for external stress corrosion cracking of stainless steel under insulation

Table 5-20 Hole size distribution in externally and ESCC corroded insulated stainless steel piping

Equivalent hole diameter	*% distribution*	
	Stable (leak)	*Unstable (burst)*
Small hole	0	0
Medium hole	100	0
Large hole	0	0
Rupture	0	100

5.9.2 Internal corrosion of stainless steel

Internal corrosion of stainless steel presents itself as pitting primarily at welds and in crevices, such as at screwed connections. Control can be by monitoring temperatures and water chemistry, as increased temperature, increased salt content and increased oxygen content will increase the likelihood of pitting. Inspection can be by visual, radiography or dye penetration of accessible surfaces. Once damage has been initiated, it will progress rapidly to failure and is therefore not suitable for inspection.

Degradation of stainless steels in water results in local attack, typically pitting or crevice corrosion, the onset of which is assumed to be controlled by temperature, given that the water conditions are as specified in Table 5-6. The PoF per unit wall thickness for the different materials and water types is given as a function of temperature in Figure 5-6. The hole size distribution is given in Table 5-21.

The assessment procedure is as below:

1) Select the appropriate water category in Table 5-6.
2) Select the curve for the material in Figure 5-6. Read off the PoF for a given temperature.
3) Divide the result by the wall thickness in mm, to give the PoF.

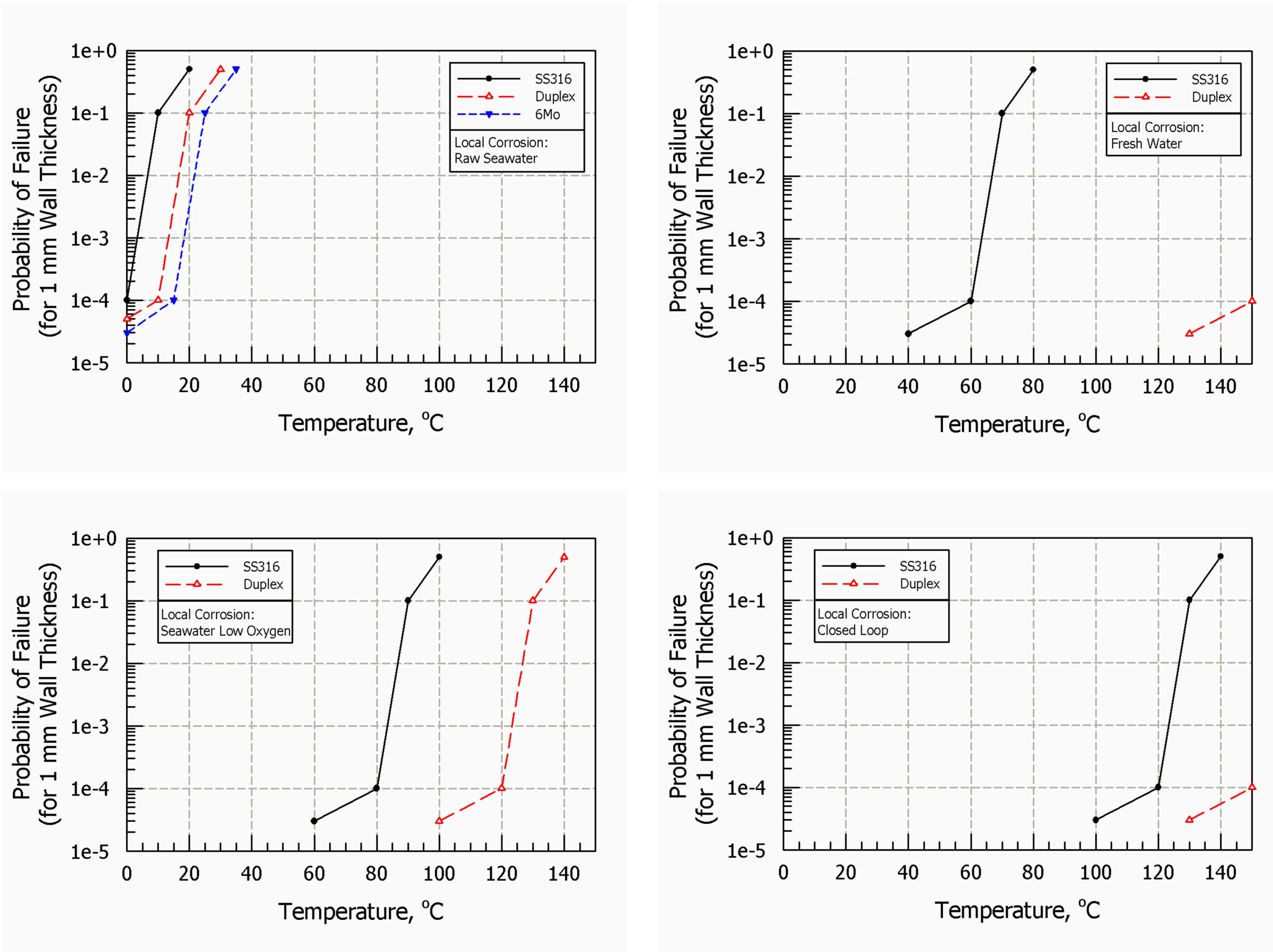

Figure 5-6 Probability of failure by water category for stainless steels

Table 5-21 Hole size distribution in stainless steel piping internally degraded by aqueous corrosion

Equivalent hole diameter	*% distribution*
Small hole	100
Medium hole	0
Large hole	0
Rupture	0

5.10 Copper-nickel alloys

5.10.1 External corrosion of copper-nickel alloys

5.10.1.1 External corrosion of copper-nickel alloys - Unisulated

Most of the copper-nickel alloys are resistant to corrosion in marine environments, hence no external degradation is expected. A fixed PoF of 10^{-5} should be assigned.

5.10.1.2 External corrosion of copper-nickel alloys — insulated

Most of the copper-nickel alloys are resistant to CUI, hence no external degradation is expected. A fixed PoF of 10^{-5} should be assigned.

5.10.2 Internal corrosion of copper-nickel alloys

Many copper-based alloys have good or reasonable corrosion resistance to quiet seawater. High rates of erosion-corrosioncan occur in flowing seawater, which is probably due to a loss of protective scale as a result of shear stress at the liquid-scale interface, and an increased oxygen concentration at the surface. The corrosion rate increases with an increase in temperature and an increase in the amount of particulate matter in the water.

While little corrosion is expected in desalinated and potable water categories, at times, stagnant conditions supporting sulphate-reducing bacteria, can lead to high local corrosion rates.

This erosion-corrosion is not limited to bends and may occur in straight sections also. The damage can be detected by wall thickness measurements made by ultrasonic testing of the area.

Determine the PoF as follows:

1) If the flow rate is above 2 m/s then set PoF =1.0 and refer to a specialist.
2) Identify the water category from the systems and water categories in Table 5-6.
3) If the materials are not included in Table 5-1, then set PoF =1.0 and refer to a specialist.
4) Select the mean rate and standard distributions, as directed in Table 5-22.
5) The PoF is calculated using the 'uniform' damage morphology.
6) Select the hole sizes as given in Table 5-23.

Table 5-22 Corrosion rates in copper-based alloy piping by different categories of water

Water categories	*Condition*	*Mean [mm/year]*	*Standard deviation [mm/year]*
Raw seawater	Flow rate < 1 m/s	0.08	0.01
	Flow rate > 1 m/s	0.2	0.1
Seawater + biocide /chlorination	Flow rate < 1 m/s	0.08	0.01
	Flow rate > 1 m/s	0.2	0.1
Seawater low oxygen		0.02	0.02
Seawater low oxygen + biocide		0.02	0.02
Seawater low oxygen + chlorination		0.02	0.02
Seawater low oxygen + biocide + chlorination		0.02	0.02
Fresh water		0.015	0.05

Water categories	*Condition*	*Mean [mm/year]*	*Standard deviation [mm/year]*
Closed loop		0.015	0.05
Exposed drains	Flow rate < 1 m/s	0.08	0.01
	Flow rate > 1 m/s	0.2	0.1
Sanitary drains		0.05	0.05

Table 5-23 Hole size distribution in copper-based alloy piping internally degraded by aqueous corrosion

Equivalent hole diameter	*% distribution*
Small hole	0
Medium hole	0
Large hole	100
Rupture	0

5.11 Titanium

5.11.1 External corrosion of titanium

5.11.1.1 External corrosion of titanium — uninsulated

No external degradation of titanium is expected in marine environments, so a fixed PoF of 10^{-5} should be assigned.

5.11.1.2 External corrosion of titanium — insulated

No CUI of titanium is expected, so a fixed PoF of 10^{-5} should be assigned.

5.11.2 Internal corrosion of titanium

No degradation of titanium is expected in the water categories described, so a fixed PoF of 10^{-5} should be assigned. To facilitate the calculation of consequence, the hole size distribution should be considered as given in Table 5-22.

Table 5-24 Hole size distribution in titanium piping internally degraded by aqueous corrosion

Equivalent hole diameter	*% distribution*
Small hole	100
Medium hole	0
Large hole	0
Rupture	0

5.12 Fibre reinforced polymer

DFI and testing should be carried out in accordance with fibre reinforced polymer (FRP) piping specifications. Supports for pipe and heavy fittings, jointing design and construction should be checked. FRP piping is susceptible to mechanical damage due to being stood on, used as a support for ladders, and damage due to welding spatter falling from welding and cutting operations. In addition, FRP is susceptible to degradation of the polymer matrix due to exposure to ultraviolet radiation from sunlight and welding.

In the absence of sound degradation models, and unless the analyst has experience with FRP, it is recommended that FRP is allocated a low reliability, i.e. PoF =1.0, and calculated on this basis and that high risk items are referred to a specialist.

The hole sizes for FRP required to calculate consequences are given in Table 5-25.

Table 5-25 Hole size distribution in fibre reinforced polymer piping internally degraded by aqueous corrosion

Equivalent hole diameter	*% distribution*
Small hole	0
Medium hole	0
Large hole	0
Rupture	100

5.13 Summary of some external degradation mechanisms

Table 5-26 gives a summery of the most common external degradation mechanisms.

Table 5-26 External corrosion descriptions

Mechanism	*Material*	*Morphology*	*Inspection guidance*
Atmospheric corrosion	Carbon steel	Areas of damage resulting in smaller size holes usually associated with coating damage or deterioration. Exasperated in areas where wetting is prolonged, including condensation. Supporting clamps are especially susceptible to this type of corrosion.	Minimum surveillance is required to periodically assess levels of corrosion, particularly the coating condition.
	Stainless steels Nickel-based alloys	Incipient attack, but small size holes associated with local attack where geometry allows damp salts to collect.	Visual surveillance is required to check conditions. Attention should be focused on geometry, clips, supports, etc., that can collect water and promote a crevice attack. Coatings, if used, should be checked.
	Titanium	No damage expected.	Minimum surveillance.

Mechanism	*Material*	*Morphology*	*Inspection guidance*
Corrosion under insulation	Carbon steel	Patches of damage where water can collect in insulation. Coatings may be used.	The damage is controlled by water ingress through the insulation. Deterioration of any coating will affect the overall resistance. Visual inspection of weather protection is recommended to inspect for leaks to locate potentially damaged areas. Radiographic testing and ultrasonic testing can be used for sizing and monitoring.
	Stainless steels Nickel-based alloys	As above, welds are likely to have lower resistance than the parent material. Coatings may be used.	As above. Monitoring of damage by inspection is not recommended, due to a rapid growth period. Corrective maintenance of weather protection systems for damage and preventative maintenance, is more important.
	Titanium	No damage expected.	Minimum surveillance.
External stress cracking under insulation	Stainless steels, but not 6Mo type	Surface cracks where water can collect at elevated temperatures under insulation. Welds are particularly susceptible.	The damage is controlled by water ingress through the insulation. Deterioration of any coating will affect the overall resistance. Visual inspection of weather protection is recommended to inspect for leaks to locate potentially damaged areas. Penetrant testing, radiographic testing and ultrasonic testing can be used to find cracks. Monitoring of damage by inspection is not recommended due to a rapid growth period. Corrective maintenance for damage and preventative maintenance of weather protection systems are more important.

SECTION 6 CONSEQUENCE OF FAILURE ASSESSMENT

6.1 Understanding consequence of failure

6.1.1 Introduction

CoF is defined for all consequences that are of importance to the operator, such as safety, economy and environment. For the purposes of RBI, the CoF is defined as the outcome of a leak given that the leak occurs.

Table 6-1 gives an overview of the factors to consider when evaluating the CoF. To further appreciate the different aspects that need to be considered when carrying out a consequence analysis, some important principles are presented below.

The consequences of a release that lead to a fire or explosion demand other considerations than a release of a fluid or gas that does not ignite. It is common practice to address the consequence calculations and their different outcomes with respect to safety, economic and environmental consequences for ignited and unignited releases separately.

It is common practice to evaluate consequences based on leak rates. Leak rates are closely related to leak hole sizes, and leak hole sizes are again dependent on degradation mechanisms. Evaluations based on leak rates ensure that the estimated consequences can more fully reflect the actual circumstances of the leak. The expected hole size distribution may vary from a pinhole, to a complete breach of the component, depending on the degradation mechanism.

Table 6-1 Factors to consider in a consequence assessment

Ignited leak		
Safety consequence	*Economic consequence*	*Environmental consequence*
Consider loss of life due to: — burns to personnel — direct blast effects to personnel — indirect blast effects to personnel (missiles, falling objects) — injuries sustained during escape and evacuation.	Consider the costs of: — repair of damage to equipment and structure — replacement of equipment and structural items — deferred production — damage to reputation.	Consider the effects of: — toxic gas release — smoke.
Unignited leak		
Safety consequence	Economic consequence	Environmental consequence
Consider loss of life due to: — toxic gas release — asphyxiating gas release — impingement of high pressure fluids on personnel.	Consider the costs of: — deferred production — repairs.	Consider the effects of: — hydrocarbon liquids spilled into the sea.

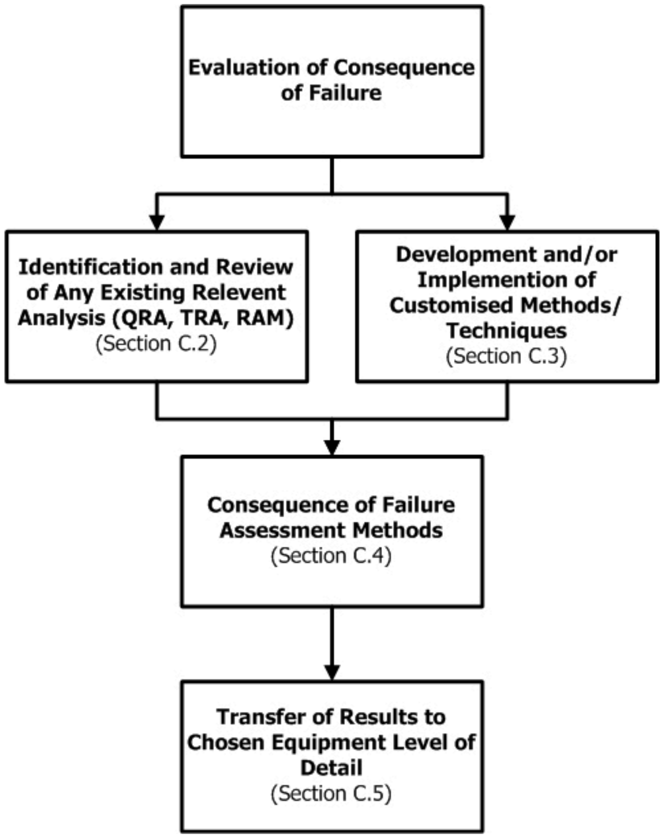

Figure 6-1 Overview of consequence of failure working process

6.1.2 Evaluation of consequence of failure

The recommendations are based on working at levels of details 1 and 2 (system level and ESD segment level, see [4.3]) before transferring results to a lower level of detail. Figure 6-1 illustrates the process of evaluating the consequences of leaks.

6.1.3 System review - description and modelling

This chapter describes the review, description and modelling of:

— Modules: the topsides of offshore installations are usually built as discrete modules, having specific functions, and active and passive barriers that contain or mitigate effects of failures. It is therefore general practice to address the consequences for each module. The key parameters for each module are:

  — the dimensions
  — the ventilation rates, natural or forced
  — the type of barriers applied, e.g. walls, floors. In particular, the explosion and fire resistance of the barriers shall be reviewed
  — the number of ignition sources in the modules, in particular, the number of pumps, compressors and generators
  — the number of hot work hours in relation to actual platform practices
  — configuration with regard to isolatable segments.

- Isolatable segments: the isolatable segment, or inventory group, is associated with the maximum amount of hazardous fluid that can be released in the event of a leak. The amount of hazardous fluid contained in an isolatable segment depends on the inventory of process equipment and piping, and the location of emergency shut down valves (ESDV). These valves serve to isolate a leak, and to contain the release of hazardous fluid. ESDVs are generally located at the import and export risers, and at strategic locations, e.g. to isolate the separator(s), and the gas compression segment. For each isolatable segment, a product service code will need to be chosen to represent the accidentally released fluid that will be evaluated. A fluid is evaluated as flammable or toxic, but it should be noted that some fluids, e.g. hydrogen sulphide, are both flammable and toxic. Also, some fluids are mixtures (e.g. methane, ethane, carbon dioxide and hydrogen sulphide), which require the use of 'representative fluids'. Care shall be taken in selecting the appropriate representative fluid, in particular when a predominantly flammable mixture, e.g. well gas, has a high concentration of toxic fluid, e.g. hydrogen sulphide. In case the fluid is a mixture of hydrocarbons, it is recommended to use the hydrocarbon with highest mol%, or a weighted hydrocarbon based on the average molecular weight of the mixture.
- Deferred production profiles: the amount of deferred production will depend strongly upon the design of the installation process system(s) and their interaction. Production systems with several parallel trains can usually be operated with one train isolated so that the installation will be able to produce at a reduced rate until the damaged train is repaired and re-commissioned. This review involves the production process from well to export facilities. Each segment of piping and each piece of equipment is evaluated to determine what the effect on production would be if a leak arose in it. Deferred production profiles are developed based on the leak evaluation. Utility systems should be included because in many cases their failure will cause a process failure, e.g. water injection, instrument air, chemical injection, or require shutdown, e.g. unserviceable firewater.

6.1.4 Mass leak rates for gas and oil

The leak rate is a function of the fluid released, phase, pressure and temperature. Mass leak rates are expressed as a function of pressure and hole size in Figure 6-2 and Figure 6-3, for gas and oil respectively, based on representative fluid and gas densities. The release rates are substantially affected by the hole size, which is why separate event trees are developed for different hole sizes.

Once the leak rates have been determined, the next step is to model the dispersion of fluid. Pressurised gaseous releases will mix with the air. Liquid releases can form aerosols, e.g. spray release, or form as pools, which could evaporate. Dispersion is required in order to form a flammable or toxic vapour cloud that affects personnel and equipment. Dispersion calculations generally require the use of detailed computer simulation models that need input about, e.g. the volume of the module, the air change rate, the density of the leaking fluid and the flash fraction. The volume of the module can be corrected for major 'obstacles' present in the module, e.g. separate rooms and large equipment. If the module is mechanically ventilated, the air change rate can be based on the design capacity of the heating, ventilation and air conditioning system. If the module is naturally ventilated, the air change rate is often a function of the geometry of the module, wind speed and predominant wind direction. The flash fraction refers to the fraction of volume released that is in a gas phase, and is equal to 1 for gas. The value for oil will depend on the fraction of gas within the process stream.

For more information, especially regarding safety consequences, see ISO 17776. It presents different tools and techniques for identifying and assessing hazards and risks. It also refers to documents that supply more detailed information. It is also useful to review any available QRAs, and preferably from different suppliers, as QRAs can be carried out in many different ways.

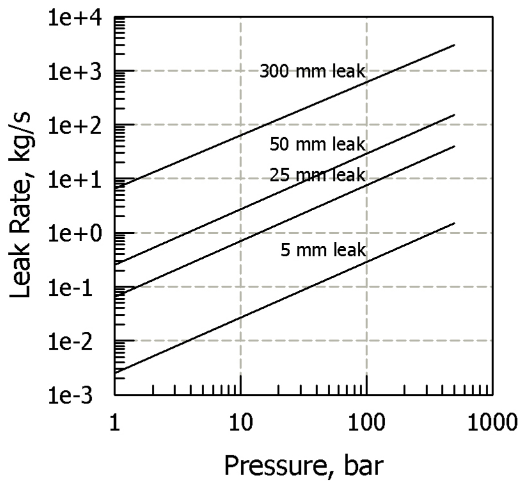

Figure 6-2 Mass leak rate gas, density = 20 kg/m^3

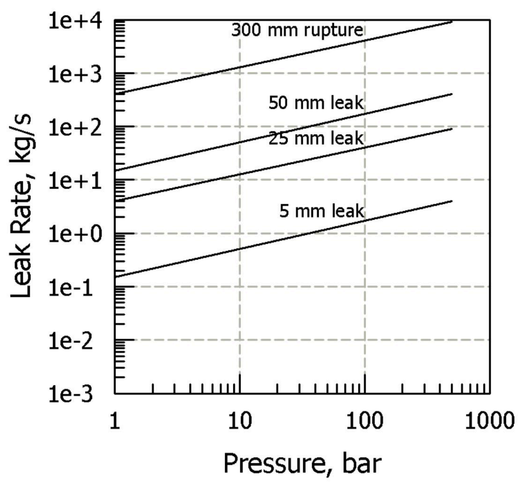

Figure 6-3 Mass leak rate oil, density = 850 kg/m^3

6.1.5 Hole size correction

When the event sizes are defined by initial release rate and not hole size, it will be necessary to determine which hole sizes relate to which release rates in order to allocate the consequences for the event. The match between hole sizes and release rates will vary from segment to segment since the pressures and fluids may vary.

An approximation of the hole size *d(m)* from the release rate and pressure can be given as follows or, less precisely, from Figure 6-2 and/or Figure 6-3, for gas release (approximation for methane):

$$d(m) = \sqrt{\frac{4QT_i}{\pi C_D P_i} 0.585 \sqrt{\frac{k}{R}}}$$

where:

Q = initial release rate [kg/sec]
T_i = initial temperature of the segment [K]
C_D = discharge coefficient, usually 0.85 for gases
P_i = initial pressure of the segment [N/m^2]
k = gas constant given by C_P/C_V = 1.3 for natural gas
R = gas constant=8.314 J/K.mol.

and for liquid release:

$$d(m) = \sqrt{\frac{4Q}{\pi C_D\sqrt{2\rho\left(P - P_a\right)}}}$$

where:

Q = initial release rate [kg/sec]
C_D = discharge coefficient, usually 0.61 for liquids
ρ = liquid density [kg/m^3]
P = pressure of the segment [N/m^2]
P_a = atmospheric pressure = 105 N/m^2.

6.1.6 Ignition probability correction

The probability of ignition is a function of concentration of gas in a module, which is itself a function of leak rate and ventilation rate. It is necessary to resolve the differences in hole size since the leak rate depends on the hole size. Should there be differences that lead to a correction of hole sizes, then the probabilities of ignition will also need to be corrected.

The probability of ignition is a function of the concentration of gas in relation to the lower explosive limit, and the number and type of ignition sources. Since using a different hole size will affect the calculated gas leak rate, the probability of ignition will vary with the mass leak rate, which is a function of the hole area. Therefore, probability of ignition will vary with the square of the hole diameter.

The probability of ignition for the RBI P^{ign}_{RBI} should be adjusted by the square of the differences in hole size between the QRA and RBI, given by:

$$P^{ign}_{RBI} = P^{ign}_{QRA}\frac{diameter^2_{QRA}}{diameter^2_{RBI}}$$

where:

P^{ign}_{QRA} = QRA probability of ignition
$diameter_{QRA}$ = QRA leak hole diameter
$diameter_{RBI}$ = RBI leak hole diameter.

6.2 Identification and review of existing analyses

6.2.1 Background

It is recommended to reuse any existing analyses. Examples of typical analyses that may contain relevant information that can be reused in an RBI context are QRAs, total risk analyses (TRA) and reliability, availability and maintainability analyses (RAM). Reuse of QRAs is the most common case.

It is recommended that qualified personnel are involved in the process of identifying, reviewing and specifying any reuse of such material. If feasible, the people responsible for the development of the chosen material should preferably be involved.

In the case where a QRA or any such analysis is available, the results can be used in the RBI. However, the following comments are made:

— If a QRA is available, the results may be used as input to the RBI CoF analysis. However, often the QRA is focused on safety consequences, which implies that the environmental and economic impact will still need to be considered separately.

— It should be noted that QRA analyses are usually based upon general failure frequencies. RBI should not be based on these general data, since the failure frequency should be specific to the degradation mechanisms of specific components. Therefore, these general failure frequencies should be removed and replaced with the specific PoF calculated using this RP, see Sec.5. Furthermore, the QRA may not have applied the same hole size distribution as those used in this RP, i.e. only the consequence assessment of the QRA should be used. The failure frequencies and hole size distribution should be replaced based on specific degradation mechanisms, see Sec.5.

6.2.2 Guidelines – quantitative risk analysis for personnel consequence of failure

The following guidelines are proposed for the use of existing QRAs in a RBI analysis, and are applicable for personnel CoF only:

1) Identify the isolatable segment limits used in the QRA. This should be done in parallel with the first activity described in [6.1.3].
2) Obtain the event trees for the relevant segments.
3) Determine the risk level arising from inspectable events.
4) Remove the general failure rate component from the event tree. The QRA event tree will show a leak frequency as the initiating event based on historical or other data, and should be removed. The end event frequencies should be divided by the leak frequency to get the end event frequencies given a leak. The PoF assessment is then used to estimate the leak probability for the final risk assessment.
5) Check whether the hole sizes used in the QRA are relevant to a RBI. To be relevant, the RBI degradation mechanism assessments should be available. If the QRA hole sizes are not readily available, these can be calculated by qualified risk/process personnel or by using the simplified methods outlined in [6.1.5]. If the QRA hole sizes are close to those required by the RBI degradation mechanism assessments, then the QRA hole sizes can be kept and the event tree may be used directly, with correction for leak frequency only. Otherwise:

   — use the event tree as is, with correction for leak frequency only, by conservatively mapping hole sizes
   — or correct for probabilities of ignition based on corrected hole sizes. Corrected probabilities of ignition shall be calculated by qualified risk/process personnel or by using the simplified method outlined in [6.1.6].

6) Tabulate corrected personnel CoF per segment with respect to the four hole sizes, see Table 5-4.
7) Identify the part diameters present in the segment.

8) Assign CoF based on the hole size distribution for that degradation mechanism, taking care that a hole size in excess of the part diameter is not used.

6.2.3 Guidelines – quantitative risk analysis for economic consequence of failure

The following steps should be carried out to use existing QRA results in a RBI covering economic consequence assessments:

1) From the safety risk assessment, determine which end events contribute to fire and explosion for each combination of segment, materials and degradation.
2) Determine what changes need to be made to the probability of ignition based on hole size differences between QRA and this RP.
3) Determine from the QRA the end event probabilities for these events.
4) Determine the likely extent of damage to the equipment and structure, using, e.g. equipment count/ value, rebuilding time and cost.
5) Multiply the end event probabilities by the cost of that end event, and sum up for the specific hole sizes for that segment, taking the values in the same distribution as the hole size distribution to give the final economic consequence for that segment and degradation mechanism.

6.3 Development and implementation of customised methods and techniques

6.3.1 Steps in the consequence of failure assessment

Generally, the following steps are required to determine the consequences:

— System description: define the system parameters of interest for the CoF assessment. Generally the 'system' will consist of the topsides of an offshore installation, or part of it.
— Develop an event tree as necessary.
— Calculate the consequences for all end event tree outcomes.
— For all combinations of isolatable segments, modules, leak sizes:
  — Calculate/estimate the event tree branch probabilities.
  — Calculate the CoF contribution of all end event tree outcomes.
  — Sum all CoF contributions to calculate the weighted total expected consequences for safety, economics and environmental impact.

Some risk analysis may result in hundreds of event tree instances.

6.3.2 Development of an event tree

The calculation of the event tree probabilities is a complex matter. The probability of ignition, given that a leak occurs, is typically a function of the leak rate, the concentration of flammable media, and the number of ignition sources within each module.

The method described in this appendix covers calculations of CoF resulting from an ignited and an unignited leak in terms of safety, economic and environmental consequences.

Figure 6-4, Figure 6-5 and Table 6-2 illustrate and explain an example of a simple event tree. More information and guidance on end events can be found in [6.3.3] and [6.3.4].

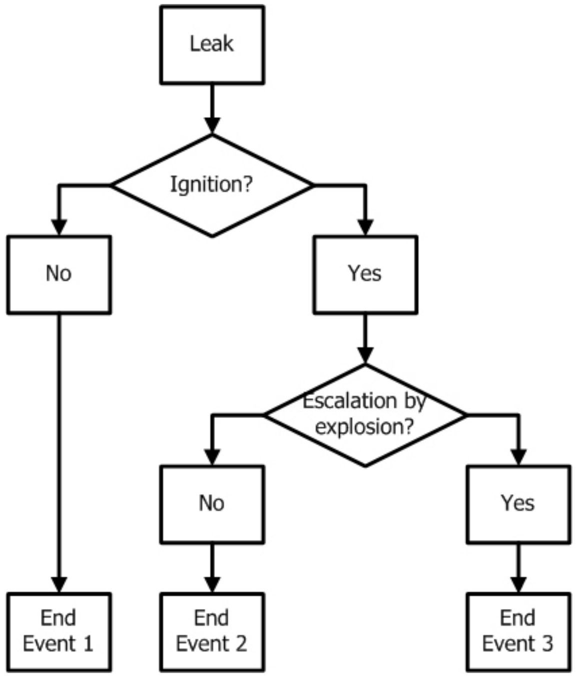

Figure 6-4 Simple event tree

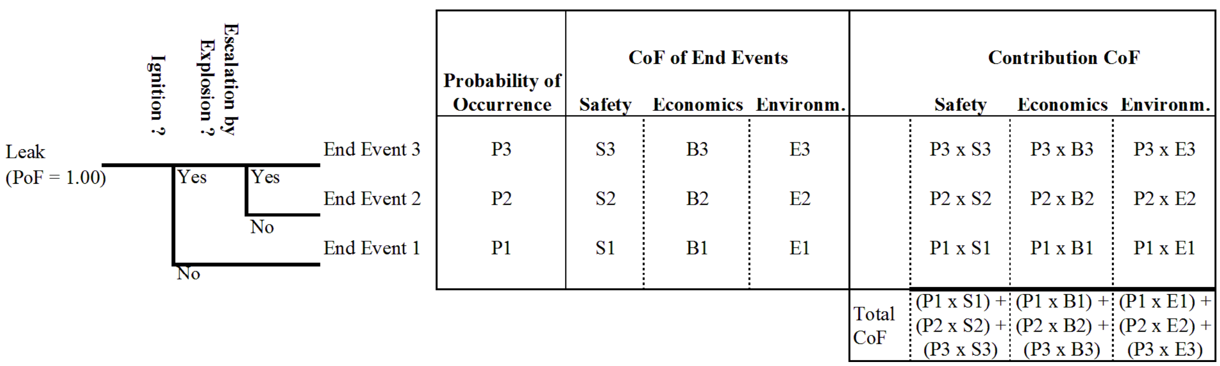

Figure 6-5 Consequence of failure calculation for a simplified event tree, one event tree per hole size

Table 6-2 Description of end events for Figure 6-4

End event no.	*Description*	*Occurrence probability*
1	There is a leak, but neither ignition nor explosion occurs.	$P_1 = \left(1 - P_{Ign}\right)$
2	There is a leak, and the leaking gas is ignited. However, there is no explosion, only a fire.	$P_2 = P_{Ign} \times \left(1 - P_{Esc}\right)$

End event no.	Description	Occurrence probability
3	There is a leak and the leaking gas is ignited followed by an explosion, giving a blast overpressure that exceeds the design capacity of the blast wall, causing damage to the neighbouring module.	$P_3 = P_{Ign} \times P_{Esc}$
where: P_{Ign} = probability of ignition P_{Esc} = probability of escalation.		

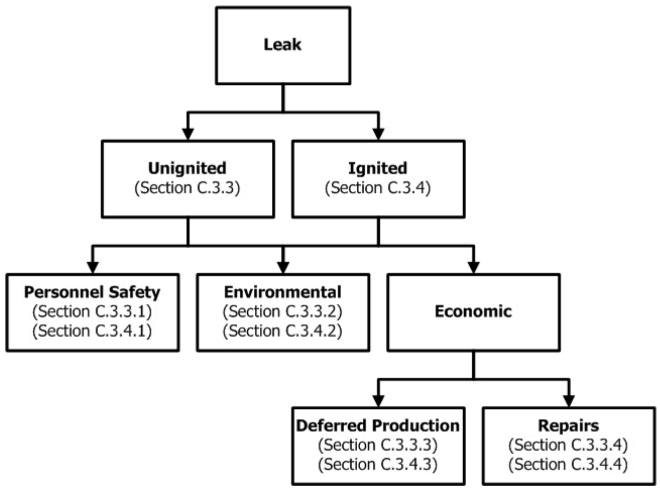

Figure 6-6 Calculation of consequence of failure

6.3.3 Consequence for end event tree outcome – unignited leaks

Unignited consequences consider the effects of any toxic release on personnel, the economic costs of deferred production and repairs, and the environmental consequence of a liquid spill in the sea.

6.3.3.1 Personnel safety consequences

Generally, pure toxic substances are not present in large quantities on offshore installations. The modelling for toxic substances is similar to that for gas and oil, and involves a release rate calculation, which can be estimated by using Figure 6-2 and Figure 6-3, dispersion, and hence the gas concentration, and consequence/impact assessment.

Note that nitrogen and carbon dioxide can have an asphyxiating effect since they replace the oxygen available in air. In high concentrations, which generally occurs in confined areas, these gases could cause fatal injury to personnel. The safety consequences are determined by the remaining concentration of oxygen in the air. A certain percentage of fatalities can be assumed in a module if the oxygen concentration goes below a certain vol%.

Hydrogen sulphide is a highly toxic substance, but does not generally exist in pure form on an offshore installation. Hydrogen sulphide is mostly found as a component in a hydrocarbon mixture. It is the most serious toxic gas encountered offshore and it has a greater explosive limit range than methane. The safety consequences for the non-ignited event are determined by the concentration of hydrogen sulphide and the exposure time. The fatality rate is normally calculated from a fluid specific probit relation, which requires the concentration of toxic gas in the confined area, in this case the module, and the exposure time as input. For carrying out simplified RBI assessments, it may be an advantage to work with a single value criterion, i.e. to relate the fatality fraction to the concentration only. A person exposed to a hydrogen sulphide vapour with a concentration between 500-1000 ppm will suffer from eye irritation, vomiting and possibly immediate acute poisoning. LC50 values, i.e. the concentrations at which 50% of the exposed population is killed, for 30 minutes exposure are in the range of 450 to 1600 ppm, depending on which literature source is quoted.

6.3.3.2 Environmental consequences

In considering environmental consequences, releases can be classified as oil, oil condensate, gas or chemical.

Chemical releases are usually subject to legislative, or company imposed limits for releases into the environment. The consequences of exceeding these limits are typically case by case fines.

The measurement units for environmental consequences can be volume or mass released, or units of currency.

The use of mass or volume released facilitates the calculation, since the contents, phase and volume of the ESD segments are used elsewhere in consequence calculations.

In the case where environmental consequences shall be measured in volume of liquids lost to the sea, it is necessary to estimate the volume for each relevant system and segment.

It will be necessary to determine the amount of liquid that will fall into the sea and not be contained within bunding or by plated decks and drains. It will depend strongly on the design of the installation as well as the position of the leaking part, the pressure within the system, the monitoring devices and the volume that can be lost.

A coarse approximation can be used. Assume that all liquid contained within a system or segment is released by a leak, resulting in a pool of the same volume as was contained within the system or segment. An estimation of the capacity of the drains to handle such a volume without overflowing to the sea can be made if the decking in the area is plated. Where the deck is made from grating, then the entire spilled volume can be assumed to fall through. If there is plated deck below, then estimate the drain capacity as before.

If the estimated volume of liquids reaching the sea is unacceptable, a more detailed estimation can be made on the basis of expected leak size and location. The consequence estimation will be coupled to the degradation mechanism for leak size and location, and can account for slower leak rates than what was used in the coarse approximation.

The consequences of oil releases can be associated with political repercussions, a damaged reputation and clean-up costs. Environmental consequences from offshore topside oil leaks are considered to present only minor damage to global and local biotopes. Generally, the volume that can be released is limited to the contents of the equipment, and even more so by the contents of an isolatable segment. Releases from pipelines, drilling activities and from storage vessels represent a significantly larger volume and shall be evaluated separately.

Direct costs related to oil releases are mainly related to the clean-up costs if the spill drifts towards shore. The actual effect will depend on the location of the field, oil type, oil drift conditions, temperature, evaporation, etc. For a given case, a fixed money value per tonne of oil released may be used.

The cost of clean-up for ship accidents may vary between USD 700 to USD 50 000 per tonne released, typically for accidents close to shore. Offshore platforms are usually located several miles offshore and USD 10 000/tonne is suggested as a conservative value for application in a coarse evaluation, when company goals or other data basis is unavailable. The cost consequence for oil release, in monetary units per volume unit is given by:

$$C_{Environment} = V_{Release} \times (C_{Clean-up} + C_{Lost\ product})$$

where:

$V_{Release}$	=	volume of oil released into the sea
$C_{Clean-up}$	=	cost of cleanup, monetary units per released volume units
$C_{Lost\ product}$	=	cost of oil that is lost in the release, monetary units per volume.

Note that the $V_{Release}$ can be adjusted to account for specific factors on the installation, e.g.:

— The volume of oil released will be affected by the phases in the isolatable segment. E.g., in a two-phase system, the oil content will be less than the total volume.

— A possible oil release from systems such as produced water or oily water.
— Not all oil from a release may reach the sea: drains and flooring may reduce the volume reaching the sea.

6.3.3.2.1 Gas release
Gas releases to the atmosphere have received less attention than oil releases and are more typically controlled releases subject to taxation or concessions for flaring or venting. Accidental releases may be subject to fines issued on a case by case basis depending on specific circumstances.

6.3.3.2.2 Other fluids
A number of chemicals are used offshore for inhibition, chemical treatment, etc., that may be harmful to the environment. Chemical releases are usually subject to legislative or company imposed limits for release of certain chemicals into the environment. The consequence of exceeding these limits is typically fines that are stipulated on a case by case basis depending on the circumstances.

6.3.3.3 Economic consequences — cost of deferred production
The value of deferred production is calculated as the value of production per hour multiplied by the number of hours at the reduced production rate. It can be expressed as a net present value using a suitable discount rate, or as a fixed currency sum.

The amount of deferred production will depend strongly on the design of the installation process system(s) and their interaction. Production systems with several parallel trains can usually be operated with one train isolated, so that the installation will be able to produce at a reduced rate until the damaged train is repaired and recommissioned. The value of deferred production will therefore be less than for a single-train installation where any leak will require a full production stop during the entire extent of the repair.

The production loss profile for each part of the pressure-retaining systems is preferably defined so that it can be applied to all parts of that system or subsystem. The profile can typically include the time taken for repair plus the time to restorr production since the production stop or reduction.

Each part of the installation's systems that has an effect on production should be assigned a production loss profile. These profiles describe the amount of production that can occur from the time a leak begins, until the repairs are complete and normal operations resume. The profiles can represent the production loss over time for individual equipment and piping items.

The evaluations and estimates can be based on the PFDs and P&IDs for the installation. They involve reviewing the production process from the wells to the export facilities, determining what the effect on production would be if a leak arose in each segment of piping and each piece of equipment, and developing the production loss profiles .

Utilities systems are also typically included because in many cases their failure will cause failure of the process, e.g. water injection, instrument air, chemical injection, or require shutdown, e.g. unserviceable firewater.

The following steps can be applied:

1) Review the contents of the part. If it is hydrocarbon-containing, a leak is likely to give rise to an alarm and production shutdown. There may be a delay while the area is degassed and made safe. If the contents are non-hazardous, then there may not be a shutdown, but if there is, then there may be some time taken in finding and eliminating the leak.
2) Determine if there are parallel trains that can be isolated from the leaking segment. After isolation, production may be able to recommence at a lower rate, depending on the capacity of the parallel trains.
3) Determine the time taken to increase the production from one level, e.g. from run-up or partial run-up, to another. It will be different for each installation and reservoir conditions, and is typically determined through consultation with the operations personnel for the installation.
4) Estimate the repair or replacement times that are likely, include availability of repair/replacement equipment, dimensions of the piping and equipment to be repaired, the service of the equipment, e.g. hazardous or non-hazardous, materials of construction, the size of the leak and the company maintenance and repair strategy.

6.3.3.4 Economic consequences — cost of repairs

Similar to ignited end events, it will be necessary to judge the extent of damage from a leak within a module, and from that the cost of repairs and replacement. Very often these costs are limited to the failing equipment/piping itself, or the equipment/piping in its direct vicinity. Generally, these costs will be small compared to the cost of deferred production.

The cost of repairs in terms of deferred production is contained within the production loss profiles described in [6.3.3.3], making sure that the specific repair methods are addressed where they will have an effect on the repair time. In addition, the costs of materials, man-hours, mobilisation of personnel and equipment to the installation, provision of specialist services, cleaning of the work area, etc. may be estimated in financial terms and added to the cost of deferred production.

6.3.4 Consequence for end event tree outcome — ignited leaks

Consequences for ignited leaks consider the effects of an ignited gas or liquid release on personnel, the cost of damage to the installation by fire and blast, the cost of deferred production and subsequent environmental consequences.

6.3.4.1 Personnel safety consequences

The safety consequences are calculated based on the average number of personnel present in the impaired module. A module is impaired if the leak occurs in the module, i.e. immediate consequence, or affected due to escalation, i.e. delayed consequence. In calculating the average number of fatalities, the difference in night and daytime population can be accounted for, as well as unusual operations requiring significant increases in personnel numbers, e.g. modification and operations simultaneously. As a conservative assumption, it can be conjectured that all personnel within the impaired module at the release moment are fatally injured.

6.3.4.2 Environmental consequences

In the case of ignited leaks, it is not expected that significant volumes of liquids will be deposited in the sea during the fire. However, the condition of the installation following an explosion or a severe fire may lead to leaks from wells or storage tanks.

In addition, the large amount of smoke generated by such fires may be a concern. As yet, there are no risk acceptance limits developed or calculation methods for estimating the consequence and the consequence will have to be treated qualitatively. Financial penalties may be applicable in certain cases.

There may be a political element to the environmental consequence once there has been media exposure. Consideration can also be given to a loss of reputation and a loss of share value.

6.3.4.3 Economic consequences — cost of deferred production

It is likely that production will not be possible while repairs take place. The downtime can be based on judgement. The cost of the lost or deferred production is derived as the product of downtime and deferred production.

The production loss related to major damage caused by ignition is determined by the reconstruction and repair time, which is plant specific. It is largely determined by long-lead items such as compressors, pressure vessels and heat exchangers made of special materials. For ignited cases, the downtime can be related to the amount of damage sustained, if no other data is available. A relationship derived from the *Dow's Fire and Explosion Index* (AIChE, 1994) is considered to give a reasonable correlation between property damage and repair/outage time.

a reasonable correlation between property damage and repair/outage time.

6.3.4.4 Economic consequences — cost of repairs

When estimating the damage costs, i.e. the cost of repairs and replacement, as a result of a fire or explosion, it is necessary to judge the extent of damage. Damage to the installation may be confined to a single module, or if the fire or blast is of sufficient magnitude, additional modules or the whole installation may be damaged or lost.

- In the case of a jet fire, it is expected that any items within the radius of the fire may be damaged or destroyed.
- In the case of a pool fire, all equipment that stands within the pool can be considered damaged or destroyed.
- Where equipment subject to fire loading also contains significant amounts of hydrocarbons, the effects of the fire loading and duration can be used to estimate knock-on effects. In these cases, passive and active fire protection can be considered mitigating factors.
- The blow-down capability, i.e. reducing pressure and volume of fluid available to fuel the fire, may be considered for both the leaking equipment and other equipment subject to fire loading. The effects of the fire can be adjusted accordingly.
- Further mitigating factors, such as fire and gas detection, deluge and sprinklers, together with the philosophy for their use, e.g. deluge start on confirmed gas detection and before fire detection, can be taken into account.

The costs can be taken from the project new-building data corrected for inflation and net present value, or it can be estimated on the basis of general industry knowledge. It typically includes repairs and replacement of structural, electrical, HVAC, control, piping, equipment, pumps, compressors, etc. Note that the cost of deferred production is not included in the repair cost.

6.4 Consequence of failure assessment methods

6.4.1 Introduction

In cases where existing analyses are not available or are judged inappropriate to use in the RBI context, then the CoF can be further assessed either in a qualitative, quantitative or semi-quantitative manner. These assessments methods are described in this section.

6.4.2 Quantitative assessment methods

Groups of equipment that have been defined can be further assessed by using quantitative methods.

For unignited leaks, quantitative methods for assessing the CoF can be customised based on the guidelines and descriptions given in [6.3.3].

For ignited leaks, it is recommended to use existing assessments, e.g. as described in [6.3.4]. If quantitative methods are developed for ignited leaks, these should be properly qualified, preferably by a third party.

6.4.3 Qualitative assessment methods

When applying qualitative engineering-judgement methods, it is recommended to carry out assessments by work sessions as described in App.A. It is recommended that the degradation assessment results are readily available. A customised assessment form should be developed, taking care to include a checklist with all relevant parameters and leaving enough space to document the decision processes and discussions.

Examples of qualitative ranking scales which can be used for the CoF are shown in Sec.3 of this RP's main body.

It shall always be assumed that a leak has occurred according to the configuration given by the degradation mechanism assessment.

It is important to keep a conservative mindset and also cross-check with and qualitatively calibrate against any existing quantitative assessments in order to avoid unreasonable results.

6.4.4 Semi-qualitative or semi-quantitative assessment methods

The customised assessment form can be further developed with simple rules that can be used to assign CoF categories in a semi-qualitative/semi-quantitative manner. If such a method is developed and implemented, a work session as described above should also be part of the implementation for the sake of quality verification. An example of a starting point for a semi-quantitative method is outlined below. It is based on combining information about fluid category and area classification with regard to levels of hazard.

Step 1 Classify areas on the installation. Table 6-3 is a suggested starting point for classification of areas on the installation. Should a QRA be available, or other recognised sources of similar information, a more detailed sub-classification should be possible to establish if considered beneficial to the planning process.

Step 2 Based on the area classification and Table 6-4, Table 6-5 and Table 6-6, the next step in the process is to consider the specific fluid category and allocate CoF categories, not ranges, based on installation-specific knowledge in the form of work sessions. This installation-specific knowledge would have been documented during the process of system review, description and modelling,see [6.1.3]. Any decision made to go beyond the ranges suggested in Table 6-6 should be documented and verified by a third party, e.g. an external consultant or expertise from other parts of the organisation.

Table 6-3 Classification of areas

Area class (AC) *)	*Description*
AC0	Hazardous area, QRA has not been carried out as a part of design/engineering/modification.
AC1	Hazardous area, QRA carried out/used during design/engineering/modifications. QRA based on recognised methods and preferably carried out by recognised risk management team/company.
AC2	Non-hazardous area.
*) More detailed sub-classifications can be established, e.g. AC1.1, AC1.2.	

Table 6-4 CoF categories

Category		*Description*
(A)	Insignificant	A leak implies insignificant likelihood of human injury, and insignificant environmental and economic consequences.
(B)	Minimal	A leak implies minimal likelihood of human injury and minimal environmental and economic consequences.
(C)	Low/small/minor	A leak implies small likelihood of human injury, minor environmental and economic consequences.
(D)	Normal/medium	A leak implies likelihood of human injury, significant environmental pollution or significant economic or political consequences.
(E)	High	A leak implies high likelihood of human injury, massive environmental pollution or very high economic or political consequences.

Table 6-5 Fluid categories

Fluid category	*Description*
I	— Typical non-flammable water-based fluids. — Non-flammable substances which are non-toxic gases at ambient temperature and atmospheric pressure conditions. Typical examples would be nitrogen, carbon dioxide, argon and air.
II	— Flammable or toxic substances that are liquid at ambient temperature and atmospheric pressure conditions. Typical examples would be oil petroleum products. Methanol is an example of a flammable and toxic fluid. — Non-toxic, single-phase natural gas. — Flammable or toxic fluids that are gases at ambient temperature and atmospheric pressure conditions, and which are conveyed as fluids. Typical examples would be hydrogen, natural gas that are not otherwise covered under category D, ethane, ethylene, liquefied petroleum gas, such as propane and butane, natural gas liquids, ammonia, and chlorine.

Table 6-6 Fluid categories, area classes (AC) and CoF

Fluid category	*Location class/CoF category*		
	AC 0	*AC 1*	*AC2*
I	D(E) *)	B-D(E) *)	A-D(E) *)
II	E	C-E	C-E
*) Some systems may have such an essential function that the CoF can be 'high'.			

6.5 Transfer of results to chosen equipment level of detail

Once consequences have been evaluated at assessment levels 1 and 2, i.e. system level and ESD segment level, the results can be transferred to a lower equipment level. Transferring results to a lower level involves:

— Linking tags and parts to the groups that have been defined and evaluated in the previous activities. This work can be time-consuming and error-prone as it is often done manually. It is recommended to mark up drawings such as P&IDs and break down the work into manageable packages.

— Adjusting the consequence assessments with regard to potential hole sizes and the size of the tags and parts of the lower level.

SECTION 7 RISK ACCEPTANCE

7.1 Concept

The role of inspection is to confirm whether degradation is occurring, to measure the progress of that degradation, and to help ensure that integrity can be maintained. The decision process regarding when to inspect can be done in a quantitative, qualitative or semi-quantitative/semi-qualitative manner and should be carried out separately for each type of risk.

The goal of an inspection programme is to contribute to maximising availability and profit without compromising safety. The risk acceptance limit used for planning inspection should be based on authority and management targets related to availability, profit and safety. Risk acceptance limits for inspection planning derived from such targets must not be confused with pure technical acceptance criteria such as acceptable wall thickness derived from various engineering standards. Cross-checking with relevant standards is nonetheless recommended when developing inspection plans. Furthermore, when inspection results are available, integrity may be evaluated based on such relevant engineering or fitness-for-purpose standards.

7.2 Challenges

Using the risk limit concept to plan inspection for all the static process equipment of an offshore installation presents several challenges. The most important ones are the following:

— To be able to manage installation risk so that it lies below the limits acceptable to the operator. The risk acceptance limit for each type of risk should be defined.
— As there are several risk acceptance limits, it is necessary to have a decision logic regarding the order of importance of these limits in deciding which limit is to govern the time to inspection. This order of importance should be recorded.
— It is not practical to work according to a risk acceptance limit directly at a component level. It will be necessary to make some simplifications by generalising, averaging and transferring information from a higher level down to a component level.
— Authority and management targets related to availability, profit and safety usually have a scope that is beyond the issues covered by inspection. A method for deciding on an appropriate fraction of these targets needs to be developed.

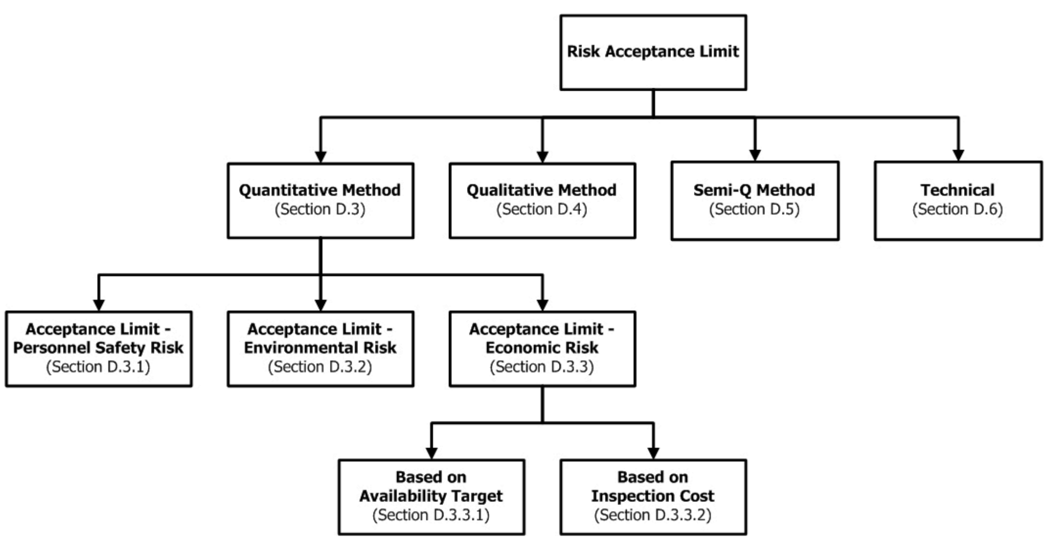

Figure 7-1 Methods for determining the risk acceptance limit

7.3 Quantitative method

When applying quantitative methods, risk acceptance limits should be established for each type of risk. These limits are used to prioritize items for inspection by deriving an inspection timing that ensures that inspection is carried out before the risk acceptance limit is breached. Timely inspection allows either the reassessment of the risk because of better information, detailed evaluation of any damage, or the timely repair or replacement of a degraded component. The derived inspection timing is calculated based on the specific characteristics of the plant and components being analysed. An example is when quantitative safety limits set by authorities are used to derive a specific risk acceptance limit for a specific plant based on how the inspectable items of the plant contribute to the total risk. The risk calculated for these particular items can be compared to the authority-based risk acceptance limits in order to time their inspection.

7.3.1 Risk acceptance limit – personnel safety risk

When it comes to the risk acceptance limit related to safety, it is common practice in some regions of the world to have safety limits set by authorities. Operators need to carry out quantitative risk analyses in order to determine whether or not the safety levels on their plants are acceptable compared to the authorities' limits. In such cases, and with the help of some statistics, it is possible to derive a risk acceptance limit based on the following:

— The quantitative risk analyses usually present how process accidents are estimated to contribute to the total risk, typically 30-50% contribution.
— Statistics regarding contribution of process accidents from different types of equipment, i.e.. about 30% of process accidents occur in piping.
— Statistics regarding inspectable events. Historic data show that corrosion causes about 30% of piping failures in the process system.

The idea is to use this type of information to derive an acceptance limit that represents a fair share of the total risk acceptance limit set by the authorities. The derived limit needs to be divided again among the components that are being planned for. It is recommended to divide the derived limit by the number of ESD segments or corrosion groups in the process system, i.e. level 2 in the equipment hierarchy presented in [4.3].

7.3.2 Risk acceptance limit – environmental risk

The measurement units for calculated environmental consequences can be volume or mass released, or units of currency based on volume or mass and clean-up costs. The use of mass or volume released facilitates calculation, as the contents, phase and volume of the ESD-segment of the process are used elsewhere in consequence calculations. If clean-up costs and fines are considered when calculating the economic consequences and risks, then the environmental assessment is covered by the economic assessment. This approach is recommended if a quantitative method is chosen. If the environmental risk assessment is kept separate from the economic risk assessment, it is recommended to use qualitative methods.

7.3.3 Risk acceptance limit – economic risk

7.3.3.1 Based on availability targets

A method similar to the one used for safety acceptance limits can be used for economic risk. Information on availability targets can be broken down in the same way and used as a risk acceptance limit for planning inspection.

7.3.3.2 Based on inspection cost

When the degradation mechanism is well understood, it is possible to use an approach where inspection is carried out only when it is 'worth spending the money'. In other words, inspection is cost-effective when the economic risk and the cost of inspection are comparable. When it comes to the cost of inspection, it is not practical to give individual estimates of the inspection cost related to every one of the relevant parts. Average values should be used to begin with, and if necessary, uncertainties can be included. At later stages of the analysis, it might become relevant to look at individual components in more detail.

7.3.4 Recommended application of quantitative methods

When applying quantitative methods, it is recommended to give the safety limit first priority. The economic risk limit based on inspection costs can then be used to decide on how long inspection can wait. In other words, combining these two limits gives a cost-effective inspection plan without compromising safety.

For the parts of the process where safety is not an issue, the economic risk limit based on availability targets should be used together with the economic risk limit based on inspection cost. In other words, combining these two limits gives a cost-effective inspection plan without compromising availability targets.

7.4 Qualitative method

When qualitative or semi-quantitative methods are being used, a decision risk matrix should be applied. This matrix will typically be a general, company-specific matrix that is likely to be conservative. An example of such a matrix is shown in Figure 7-2 where the inspection interval is given by the numbers in the cells. It is recommended that such inspection intervals be dynamic intervals that are subject to change based on qualified assessments of inspection results.

Application of qualitative methods for acceptance limits and inspection times requires highly experienced personnel, both from a general point of view and from a plant-specific point of view. The principles described for quantitative methods apply for qualitative methods also. Any judgement leading to an inspection plan should take into account many of the same matters considered when carrying out quantitative calculations.

One or several decision risk matrices covering the different risk types should be developed for the rate models, susceptibility models and any other types of models being considered.

7.5 Semi-quantitative method

This chapter is suggested as a starting point for topside applications. If it is feasible, the acceptable PoFs should be calibrated against the ones used on any of the operator’s identical or similar installations that are known to have adequate inspection management systems.

Guidance note:

- A leak in the main hydrocarbon system is a condition that can compromise the integrity of the installation.
- A leak in the utility system is a condition that renders the topside installation unsuitable for normal operations. The acceptable PoF limit is therefore chosen to be less conservative than for HC systems.
- The values in the risk matrix are based on project experience and engineering judgement.
- It is assumed that the CoF is assessed semi-quantitatively according to the example given in [6.4.4]. The consequence categories are according to Figure 7-2. The PoF assessment is assumed to have been carried out quantitatively or semi-quantitatively resulting in numerical PoF values.
- See App.D for assessing inspection timing.

---e-n-d---o-f---g-u-i-d-a-n-c-e---n-o-t-e---

PoF Ranking	PoF Description	Time to Inspect (years)				
5	(1) In a small population, one or more failures can be expected annually. (2) Failure has occurred several times a year in the location.	**Corrective Maintenance**	**4**	**2**	**1**	**1**
4	(1) In a large population, one or more failures can be expected annually. (2) Failure has occurred several times a year in operating company.	**Corrective Maintenance**	**4**	**2**	**1**	**1**
3	(1) Several failures may occur during the life of the installation for a system comprising a small number of components. (2) Failure has occurred in the operating company.	**Corrective Maintenance**	**Corrective Maintenance**	**4**	**2**	**2**
2	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	**Corrective Maintenance**	**Corrective Maintenance**	**8**	**4**	**4**
1	(1) Several failures may occur during the life of the installation for a system comprising a large number of components. (2) Failure has occurred in industry.	**Corrective Maintenance**	**Corrective Maintenance**	**8**	**8**	**8**
CoF Types	**Safety**	No Injury	Minor Injury Absence < 2 days	Major Injury Absence > 2 days	Single Fatality	Multiple Fatalities
	Envirnoment	No pollution	Minor local effect. Can be cleaned up easily.	Significant local effect. Will take more than 1 man week to remove.	Pollution has significant effect upon the surrounding ecosystem (e.g. population of birds or fish).	Pollution that can cause massive and irreparable damage to ecosystem.
	Business	No downtime or asset damage	< € 10.000 damage or downtime < one shift	< € 100.000 damage or downtime < 4 shifts	< € 1.000.000 damage or downtime < one month	< € 10.000.000 damage or downtime one year
CoF Ranking		**A**	**B**	**C**	**D**	**E**

Figure 7-2 Example of a decision risk matrix

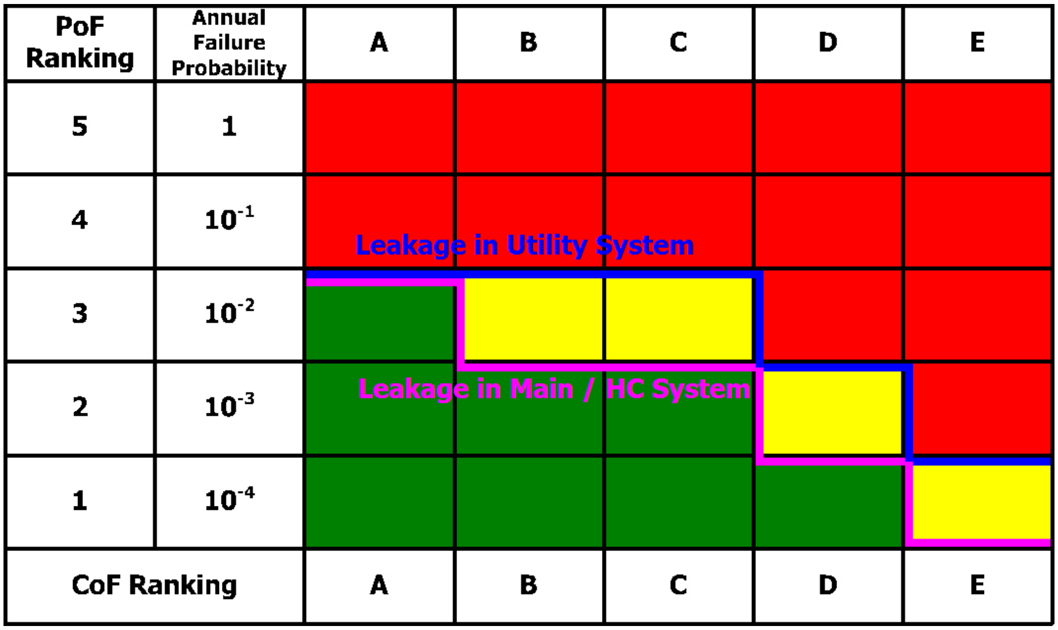

Figure 7-3 PoF acceptance limit (PoF_{Limit}) vs CoF category

Table 7-1 PoF acceptance limit (PoF_{Limit}) vs CoF category

Leakage type	*Consequence category*				
	A	*B*	*C*	*D*	*E*
Leak in utility system	10^{-2}	10^{-2}	10^{-2}	10^{-3}	10^{-4}
Leak in main/HC system	10^{-2}	10^{-3}	10^{-3}	10^{-4}	10^{-5}

7.6 Technical criteria

7.6.1 Probability of failure acceptance limit

To allow the time-to-inspection to be calculated, it is recommended that the risk acceptance limit is converted to a PoF_{Limit}. A conversion can be done using the Figure 7-3 and Table 7-1. Depending upon the CoF category, the corresponding PoF limit can be read. This limit should be expressed for each type of risk considered. Note that the same part may have more than one PoF limit, depending on the consequence type.

7.6.2 Simplified time to inspection method for different degradation models

7.6.2.1 Rate model

The method presented in this section facilitates the calculation of the time at which the PoF will equal the PoF_{Limit}. When the PoF reaches the PoF_{Limit} is also the latest and inspection should be carried out to check that the risk acceptance limit has not been exceeded.

The calculation is based on the wall (t_0) thickness, the wall thickness at which a release is expected ($t_{release}$), the mean damage rate (d_{mean}) and a confidence factor (a), to account for the uncertainty in the rate of corrosion.

The time at which (PoF = PoF_{Limit}) is given by:

$$\text{Time to PoF}_{\text{Limit}} = a\frac{t_0 - t_{release}}{d_{mean}}$$

where:

t_0	=	current wall thickness, which can be determined by inspection [mm]
$t_{release}$	=	wall thickness at which a release is expected. This wall thickness may be derived from first principles, or from appropriate standards or formula such as ASME B31.3, ASME B31G, BS PD 5500, ASME BPVC VIII and DNV-RP-F101, using relevant operational loads [mm].
d_{mean}	=	mean damage rate, which is determined using measured values, expert judgement, or the guidance in Sec.5 [mm/year].
a	=	confidence factor.

The process steps are:

1) Determine the current wall thickness by inspection.
2) Determine the wall thickness at which a release is expected.
    a) Due consideration should be given to the degradation morphology. Standards formulae generally assume a uniform wall thinning, although some include defect size assessment. For localised damage that does not affect the wall stresses, it may be acceptable to set the release wall thickness close to, or as, zero, i.e. the release due to uniform wall loss will occur at a thicker wall than local wall loss.
    b) It may be desirable to include other wall thickness criteria in the inspection plan, e.g. to check compliance with authorities' requirements. If other failure criteria are defined, such as consumption of corrosion allowance, the purpose of the evaluation should be considered and the consequences adjusted to suit, e.g. cost of remedial action, rather than a release.
    c) Some standards formulae include optional explicit safety factors. It is suggested that these are removed for the purpose of the RBI as margins are implicitly included in the calculations and vary with the risk.
    d) The standards formulae give wall thickness requirements for pressure retaining purposes. Other loads should also be considered and a thicker limit should be stipulated if the standard suggests an impractically thin wall for general thinning.
3) Determine the mean rate of corrosion (d_{mean}) from measured values, expert judgement, or using the guidance in Sec.5.
4) Determine the confidence factor (a) using the procedure given below.
    a) This simplified method uses predefined distributions, see Sec.5, and assumes that the mean damage rate is the only uncertainty variable.
    b) Determine the maximum acceptable PoF for the item using the CoF for that item and the type of risk, see [7.5].
    c) For mechanisms other than CO_2 corrosion: the confidence curves are given for three CoV only: 2.0, 1.0 and 0.33, representing high, medium and low spread respectively. A rough guide to decide the applicable CoV is given in Table 7-2. Select the curve in Figure 7-4 that is appropriate for the

degradation mechanism, including a CoV. The curves in Figure 7-4 apply to normal or lognormal distributions.

d) For CO_2 corrosion: the confidence curve for CO_2 corrosion, Figure 7-4, is given for two cases: uniform corrosion and local corrosion. These curves include the relevant CoV value. Depending upon the inspection results select the correct curve.

e) Use the selected curve, take the PoF_{Limit} on the horizontal axis and read off the corresponding confidence factor (*a*) on the other axis.

5) Calculate the time to PoF_{Limit} using the equation:

$$\text{Time to } \mathrm{PoF}_{\mathrm{Limit}} = a\frac{t_0 - t_{release}}{d_{mean}}$$

6) Determine the time to inspection. The inspection should be scheduled to occur no later than the time to PoF_{Limit}. It may be preferred to calculate the time to PoF_{Limit} for each risk type for the component of interest with the inspection scheduled for the earliest time.

Table 7-2 Definition of confidence levels

Confidence level	*Description*
High, confidence CoV ≈ 0.33	— Service conditions are well known and do not fluctuate appreciably. — Inspection results show a consistent trend, with a high correlation coefficient when plotted against time. — A highly efficient inspection method is used and the measured results are validated. — Degradation models are derived from many data sources showing results that are generally consistent. Where probabilistic models are given, the standard deviation is low.
Medium, confidence CoV ≈ 1.0	— Service conditions are well known and fluctuations are of a moderate nature. — Inspection results show a consistent trend, with some scatter and a reasonable correlation coefficient when plotted. — A normally efficient inspection method is used and the measured results are validated. — Degradation models are derived from only a small number of data sources showing results that are generally consistent. Where probabilistic models are given, the standard deviation is moderate.
Low, confidence CoV ≈ 2.0	— Service conditions are not well known or have a considerable variation in pressures, temperatures or concentration of corrosive substances. — There are no inspection results, or if they exist, they show only a general trend, with extensive scatter and a low correlation coefficient when plotted. — A fairly efficient inspection method is used and the measured results are validated. — Degradation models are derived from one data source only. Where probabilistic models are given, the standard deviation is high.

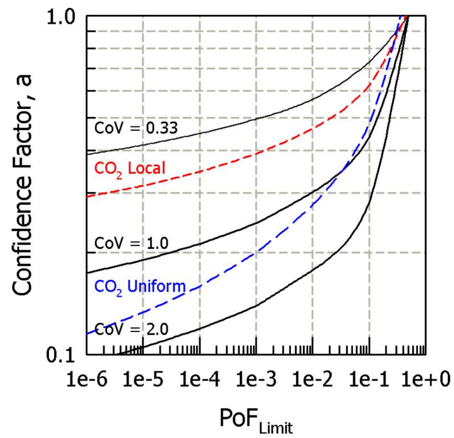

Figure 7-4 Scale factor as a function of PoF_{Limit}

7.6.2.2 Susceptibility model

For a description of susceptibility models, see Sec.5. If any of the acceptance limits are exceeded then immediate action shall be taken. This action may be one or a combination of:

— more detailed analysis
— assess and repair any damage
— change or treat the content so that it is less damaging
— reduce operating temperature
— exclude damaging environment, e.g. coating, lining, exclude water from insulation
— change material type.

As previously mentioned, the onset and development of damage are not readily detectable by inspection, which means that the economical acceptance limit should consider other factors than inspection costs.

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APPENDIX A SCREENING

A.1 Introduction

It is recommended that the risk-based screening process is carried out as a working session amongst suitably qualified personnel, including staff with specific knowledge of the asset in question. The following type of personnel should be involved, see[4.5]: materials/corrosion, inspection, process/production and safety.

It is recommended that the materials degradation and damage evaluation sheets, included with this appendix, are used during the screening process to help guide discussion.

A.2 Probability of failure

A.2.1 Introduction

Consider whether there is any possibility of failure, under the known operating conditions and taking into account the approximate chemical composition, the temperatures of the fluids and the effects of time. The boundary between low and high PoF has been set to approximately 10^{-5} per year, i.e. no significant degradation is expected with PoF of 10^{-5} or less. Figure A-1

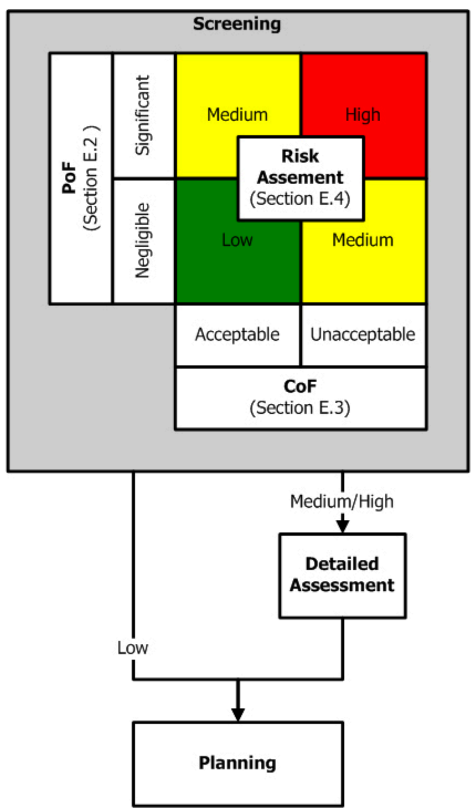

Figure A-1 Screening assessment for RBI process

It is not the intention to carry out a detailed evaluation, but to assess whether these conditions are likely to give rise to negligible degradation, i.e. 'low', or degradation rates that are not negligible, i.e. 'high'.

Care should be taken to ensure that the consideration of process conditions accounts for future variations as the reservoir becomes depleted, such as increase in water cut, temperatures, or H_2S evolution. It is important also to account for likely excursions in process parameters due to upset conditions.

Consider the following for present time, their change with time, and what might happen in upset or start-up conditions. Consider also historic events, including testing during construction and commissioning, as well as past service. Do NOT include consideration of consequence in the probability! Any other causes of failure can be included in the assessment. This can include any known or suspected abnormal conditions that can cause concern.

Guidance note:

— Data requirements and screening guidance for PoF are given in Sec.5 which treats each degradation mechanism.

— Sec.5 should be consulted for the applicable mechanism.

— Care should be taken when using the appendix for guidance on PoF to ensure that the assumptions made regarding the conditions under which the components operate are applicable to the systems in question.

---e-n-d---o-f---g-u-i-d-a-n-c-e---n-o-t-e---

A.2.2 External degradation

Consider the PoF for each material that might arise as a result of the external environment, taking account of temperatures, coatings, the presence of water-retaining insulation and the effects of time.

Prompt questions:

— Coating: is there a coating, what type is it, what is its quality, how long does it take to degrade significantly?

— Insulation: is there insulation, does it retain water, is there heat tracing, i.e. temperature effect on both internal and external degradation?

— Are there any data that indicate the current condition – e.g. inspection reports?

A.2.3 Internal degradation

Consider the PoF due to combinations of materials, fluids, gases, temperatures and pressures, also including degradation due to erosion and the passage of chemicals within the systems. Consider also likely changes in the use of the system – such as use of water injection pipework for oil production.

Prompt questions:

— Consider possible degradation mechanisms arising from materials and fluids combinations. What about CRA or polymeric linings? Internal corrosion protection systems? Internal anodes?

— What are the effects of temperatures and pressures, also partial pressures? Note these may change through the system, and metal temperatures can be affected by heat tracing.

— Consider excursions in all process parameters.

— Consider sand production rates, proppant production, acid production.

— Consider water breakthrough over time.

— Consider increases in CO_2 with time if there is gas reinjection.

— Are there any data that indicate the current condition, e.g. inspection reports?

A.2.4 Fatigue

The PoF due to fatigue can be considered. Areas where there are known or suspected problems should be evaluated, e.g. small diameter side-branches of stainless steel. The significance of vibration sources should also be considered, such as poor or damaged support systems, reciprocating equipment, unbalanced rotating equipment and fluid hammer.

Prompt questions:

— Are there areas where vibrations are expected, or have been observed?

— Have any failures occurred?

A.3 Consequence of failure

A.3.1 Introduction

Consider the following points for assessing the CoF. The worst case scenario regarding leak is usually the best case to consider – do NOT include consideration of PoF in the consequence! If required, other consequences besides safety, economic, environmental can be assessed, such as the political consequence in terms of adverse press coverage or loss of share value that could arise from a spill or fire. The definitions of these other consequences should be discussed when agreeing on the acceptance limits.

A.3.2 Personnel safety consequence

Acceptance criteria at a tag level are not always intuitively assessable in the screening session: experience shows that the boundary between 'low' and 'high' safety consequence can be taken as the possibility of personnel exposure leading to injury and a lost-time incident. Typically the loss of any flammable or toxic fluid or gas would be expected to have a 'high' safety consequence.

Prompt questions:

— What is the effect of a leak?
— Is the fluid poisonous?
— Will there be an ignition or explosion that might affect personnel?
— What is the likely population around any part of the system that might leak? Might there be deaths or injuries?

Guidance note:

— A release of a fluid that is normally accepted as being difficult to ignite, such as diesel fuel, can still result in ignition due to impingement on hot surfaces.
— A high pressure leak may result in the formation of a mist that can readily ignite in the presence of equipment or work that may generate sparks.

---e-n-d---o-f---g-u-i-d-a-n-c-e---n-o-t-e---

A.3.3 Economic consequence - deferred production, repairs

A production shutdown would normally be expected to give a 'high' economic consequence. However, consideration should be given to the installation's operational economics, such as field production profile, system redundancies and penalties that might arise from contractual production guarantees. The release into the sea of any hydrocarbon liquid or process chemical unless specifically known to be benign or of a low volume, would be expected to give a 'high' environmental consequence. Releases of gases into the air should be considered in the light of local regulations.

Prompt questions:

— What is the likely reaction to the detection of a leak? Will the platform shut down production, or partially shut down?
— Will there be damage to the installation, by a fire, explosion, or acid attack, resulting in replacement costs and lost production?
— Are there clean-up costs associated with the leak?

A.4 Risk assessment

After assignment of the probabilities and consequences, the system or vessel is assigned to detailed RBI or to maintenance activities as shown in Figure A-2. The most severe result for any of the consequence categories, combined with the most severe result for the probability categories, is used to stipulate the final outcome.

It is essential to assess whether the piping and vessels within a system experience different conditions, such as the possibility of water condensation within a vessel but not in the piping systems, and the effect of flow rates in piping and vessels on sand erosion.

The recommendations for action, as shown in Figure A-2, are developed on the basis that inspection is only effective in reducing the PoF. There may be other causes of failure with significant consequences that have not been considered because they are not within the scope of inspection.

The results of the screening process are that systems, groups or equipment items are assessed as having either 'high', 'medium' or 'low' risk:

— Items with medium and high risk should be evaluated further, see [4.8].
— Items with low risk should be considered for maintenance activity as noted in Figure A-2.
— High consequence items should also undergo checks for degradation mechanisms not considered in the screening.

A.5 Screening revision

The screening process should be periodically revised as part of the overall inspection management process to ensure that the assumptions used in the evaluations remain valid. Changes in process or other conditions may result in systems or equipment moving to high risk and being subject to more detailed RBI assessments.

A.6 Screening briefing

The following are prompt questions to aid thought and discussions. These are by no means exhaustive:

— A combination of 'high' probability and 'high' consequence necessitates a detailed RBI analysis.
— A score of 'low' for either is a recommendation for maintenance activity.
— A scope of 'low' for both is a recommendation for 'no further action'.

Note:

If the assessment leaves any cause for doubt, or information is lacking, a 'high' rating should be assigned and further assessment carried out.

---e-n-d---o-f---n-o-t-e---

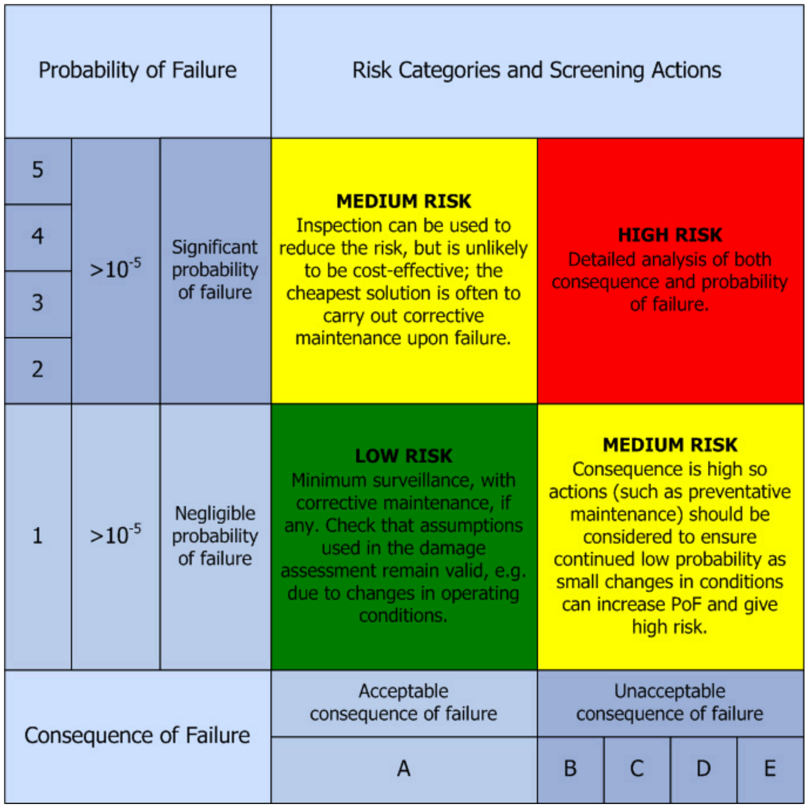

Figure A-2 Risk matrix for screening

A.7 Screening form

RBI screening form template to be used for documenting the screening assessment is presented in Table A-1.

Table A-1 RBI screening form template

<table>
<tr><td colspan="7">Installation:</td><td>Rev:</td></tr>
<tr><td colspan="7">System no:</td><td>Description:</td></tr>
<tr><td colspan="8">Function and boundaries:</td></tr>
<tr><td colspan="8">Dependent systems:</td></tr>
<tr><td colspan="8">Process and materials information</td></tr>
<tr><td>Product service code</td><td colspan="2">Material</td><td colspan="3">Op. temp.°C</td><td>Op. press barg</td><td>Chemical information/comment/reference</td></tr>
<tr><td>-</td><td colspan="2"></td><td colspan="3"></td><td></td><td></td></tr>
<tr><td>-</td><td colspan="2"></td><td colspan="3"></td><td></td><td></td></tr>
<tr><td>-</td><td colspan="2"></td><td colspan="3"></td><td></td><td></td></tr>
<tr><td colspan="8">Consequence evaluation</td></tr>
<tr><td colspan="3">Consequence</td><td colspan="4">High/Low</td><td>Justification/reasoning/reference</td></tr>
<tr><td colspan="3">Safety</td><td colspan="4"></td><td></td></tr>
<tr><td colspan="3">Economic</td><td colspan="4"></td><td></td></tr>
<tr><td colspan="3">Environmental</td><td colspan="4"></td><td></td></tr>
<tr><td colspan="3">Other</td><td colspan="4"></td><td></td></tr>
<tr><td colspan="8">Probability evaluation</td></tr>
<tr><td colspan="2">Probability</td><td colspan="3">High/Low</td><td colspan="2">Model (s)</td><td>Justification/reasoning/reference</td></tr>
<tr><td colspan="2">Internal</td><td colspan="3"></td><td colspan="2"></td><td></td></tr>
<tr><td colspan="2">External</td><td colspan="3"></td><td colspan="2"></td><td></td></tr>
<tr><td colspan="2">Fatigue</td><td colspan="3"></td><td colspan="2"></td><td></td></tr>
<tr><td colspan="8">Notes/comments:</td></tr>
<tr><td colspan="8">Further actions:</td></tr>
<tr><td colspan="8">Agreement to evaluation</td></tr>
<tr><td colspan="4">Team</td><td colspan="3"></td><td>Date</td></tr>
<tr><td colspan="4">Verification</td><td colspan="3"></td><td>Date</td></tr>
</table>

APPENDIX B MICROBIOLOGICALLY INFLUENCED CORROSION

B.1 Objective

The objective of this appendix is to provide guidance on where inspections should be carried out due to the threat of internal MIC by assessing the PoF as input to RBI and on establishing a MIC management strategy.

B.2 Background

B.2.1 General introduction to microbiologically influenced corrosion

MIC is a multilayer, evidence dependent degradation mechanism affected by the presence and/or activity of microorganisms in biofilms on the surface of the corroding material. However, the assessment of MIC is challenging due, in part, to the complex interaction between the biological, chemical and physical variables involved. Furthermore, the presence of microorganisms alone does not guarantee that MIC will occur. Microorganisms must be abundant and active to carry out their metabolic processes and thus produce byproducts that can result in localized corrosion (pitting) formation.

Generally, MIC is found internally in CS assets due to the formation of biofilms or semi-solid deposits at the metal surface. These biofilms are an agglomeration of microorganisms such as bacteria, archaea and fungi, organics such as hydrocarbons, and inorganic solids such as sand or clay. Many types and species of microorganisms, i.e. consortia, can be present in a biofilm at any particular time. Their relative abundance/ population and activity can fluctuate over time with changes in available nutrients and external conditions. The resulting environment at the bio-film-metal interface is typically anaerobic, no oxygen present, and corrosion can occur due to metabolic activity of the microorganisms or direct electron transfer with the metal. MIC can also be found externally in buried or underwater assets, and in other alloys under specific circumstances.

B.2.2 Conditions that promote microbiologically influenced corrosion

MIC can result in localized corrosion under four basic conditions:

1) presence of water, in contact with the metal surface
2) optimal microbiological growth conditions, temperature and pH
3) availability of nutrients
4) stagnant or low fluid flow.

In addition to these requirements, a number of abiotic parameters can also influence the potential for MIC including the characteristics of the process fluid such as salinity, physical or operational conditions and metallurgical factors such as materials of construction. A list of key parameters and their details is provided in Table B-1.

Table B-1 Parameters used in assessing probability of failure due to MIC (PoF_{MIC})

Parameters	*Rationale*	*Addition information*
Stagnant/stratified flow	Stagnant or low fluid flow conditions can increase the threat of MIC since these hydrodynamic conditions allow for biofilm formation and the potential for liquid water to be in contact with the metal surface. A number of design features inherently have stagnant or decreased flow rates. These include dead legs, out of service sections, sections with low elevations, bends, elbows, bypasses, closed valves, and small-bore appurtenances. Pipelines with stratified flow that allows water separation also have a greater potential for MIC.	Indirect online measurement techniques, see NACE 3T199.
Temperature/pH	The threat of MIC is enhanced when MIC-related microbial functional groups (MFGs) are within their optimum temperature/pH envelope. If operating conditions fall outside either of these windows, microbiological activity and/or abundance and the threat of MIC may be reduced. See Table B-2.	Online monitoring / water composition analysis, see NACE 3T199.
Microbiological parameters	High numbers (abundance) of active MIC related microorganisms may increase the potential for MIC. However, microbiological activity, diversity and abundance need to be linked to chemical evidence to confirm the threat of MIC (the presence of microorganisms alone is no guarantee of MIC). See Table B-2.	Activity: ATP assays, see [B.3.2.3] Diversity: Next generation sequencing/ DNA sequencing technology, see [B.3.2.3] Abundance: qPCR testing, see NACE TM0212, NACE TM0106 and NACE TM0194.
Chemical parameters	Chemical analysis of both liquid and solid samples, in conjunction with microbiological data, can help confirm the threat of MIC and/or other abiotic corrosion mechanisms. If the operating fluid possesses the chemical species required for microbiological metabolism, or if the solids or surfaces possess chemical compounds related to corrosion products resulting from MIC related microorganisms, then there is a greater potential for MIC. If the required chemical species are not found then the threat of MIC is minimized.	Composition analysis for solids, liquids and gases, see NACE 3T199.

B.2.3 Mechanics of microbiologically influenced corrosion

MIC is the result of complex interactions between:

1) electrochemical conditions
2) physical/environmental conditions
3) operational conditions
4) biological conditions

The mechanisms for MIC require the presence of an aqueous environment and they occur via electrochemical processes taking place after biofilm formation, see (Skovhus *et al.*, 2017), (Ibrahim *et al.*, 2018). Due to microbiological activity within and under biofilms, chemical byproducts change the electrical potential of the metal at a local scale. The anodic regions on the metal surface become corroded while the adjacent regions become cathodically charged. While MIC can occur in isolation, it can also be found in conjunction with other abiotic corrosion threats such as oxygen (O_2), carbon dioxide (CO_2), hydrogen sulfide (H_2S) corrosion which makes the assessment more challenging.

In the oil and gas industry, there are a wide range of microorganisms that can cause MIC, resulting a number of specific corrosion mechanisms and pathways. These microorganisms are often grouped according to metabolic functionality, which determines the necessary biochemical inputs (nutrients) and outputs (metabolites) that can lead to corrosion. These groups are also known as microbial functional groups (MFGs).

Table B-2 lists the most prevalent MIC related MFGs and their associated chemistries.

Table B-2 Common microbiologically influenced corrosion related microbial functional groups and associated parameters

Microbial functional group	*Active temperature range [°C]*	*Active pH range*	*Nutrient requirements*	*Corrosion products*
Sulfate-reducing bacteria (SRB)	10 - 74	4 - 9.5	Organic and aromatic compounds, hydrocarbons, alcohols, lactate, acetate, H_2, SO_4^{2-}, S^0, $S_2O_3^{2-}$	H_2S, sulfide (HS^-), iron sulfide (FeS)
Sulfate-reducing *archaea*(SRA)	60 - 95	4 - 9.5		
Methanogenic *archaea* (MA)	37 - 85	5 - 6	Organic compounds, CO_2 (or soluble CO_3^{2-}, HCO_3^-, H_2CO_3) or H_2	methane (CH_4), carbon monoxide (CO)
Nitrate-reducing bacteria (NRB)	15 - 25	7 - 8	Organic compounds, O_2, NO_3^-	nitrogen dioxide (NO_2^-), nitrous oxide (N_2O), nitric oxide (NO), dinitrogen (N_2)
Iron-reducing bacteria (IRB)	21 - 40	4 - 9	insoluble ferric iron (Fe^{3+}), O_2, NO_3^-	ferrous iron (Fe^{2+})
Acid-producing bacteria (APB)	15 - 90	< 7	Organic compounds, hydrocarbons, O_2	Organic acids, e.g. formic, acetic CO_2
Sulfur-oxidizing bacteria (SOB)	20 - 50	0.5 - 8	Sulfide, sulfite, elemental sulfur (S^0), thiosulfate ($S_2O_3^{-2}$), organic compounds, O_2, CO_2	sulfuric acid (H_2SO_4), Sulphur (S^0)

Microbial functional group	Active temperature range [°C]	Active pH range	Nutrient requirements	Corrosion products
Iron/Manganese-oxidizing bacteria (IOB/MnOB)	10 - 40	1 - 10	soluble ferrous iron (Fe^{2+}), Mn^{2+}	insoluble ferric iron (Fe^{3+}), Manganese (Mn^{4+})

As an example, corrosion mechanisms driven by sulfate-reducing bacteria (SRB) are commonly found in oilfield operations and, as such, are the most understood. SRB perform anaerobic respiration of sulfate (SO_4^{2-}) producing hydrogen sulfide (H_2S/HS^-) Equation (B.1) while they gain energy from organic matter (H_2). In the presence of steel, iron sulfide (Fe_xS_y) corrosion products are formed Equation (B.2) and in the presence of oxygen, sulfur species may oxidize to form elemental sulfur (S^0), which is highly corrosive.

Conversely, methanogenic archaea (MA) are microorganisms that produce methane from CO_2 using electrons from the dissolution of iron Equation (B.3). MIC mechanisms can also occur synergistically from the interaction of multiple species. An example of this is shown in Figure B-1 which demonstrates the synergistic interaction between SRB and MA.

$$SO_4^{-2} + 10H^+ + 8e^- \rightarrow H_2S + 4H_2S \qquad \text{(B.1)}$$

$$H_2S + Fe^0 \rightarrow FeS + H_2 \qquad \text{(B.2)}$$

$$HCO_3^- + 9H^+ + 8e^- \rightarrow CH_4 + 3H_2O \qquad \text{(B.3)}$$

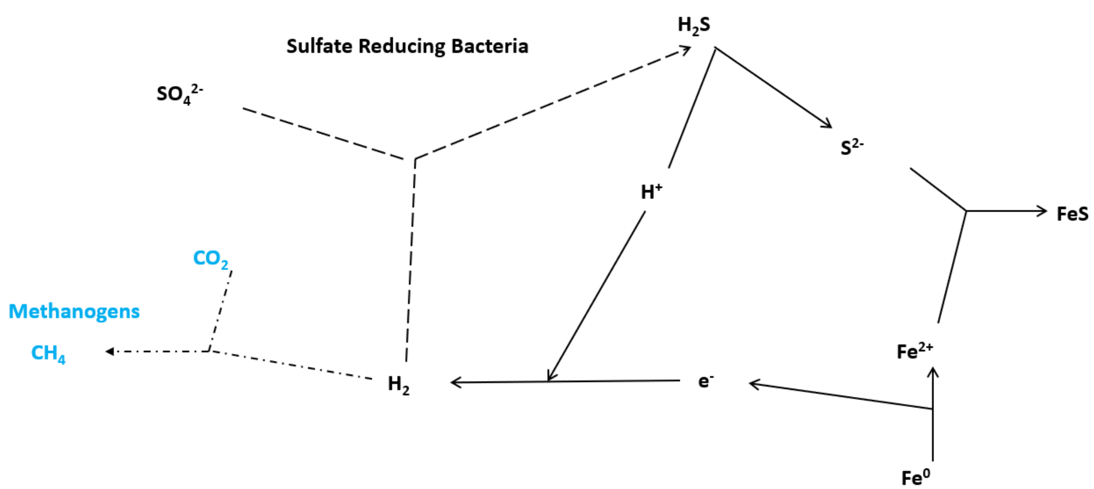

Figure B-1 Interaction between SRB and MA metabolic pathways

B.2.4 Significance of the chemical environment

The chemical environment is affected by the composition of the operating fluid and by the influence of microorganisms, which may deplete and/or add chemical compounds due to their metabolic activity. Some corrosion products can be formed by both biotic and abiotic driven mechanisms. In order to distinguish MIC from abiotic corrosion, chemical evidence from both liquid (operating fluid) and solids (scale/deposit/sludge) testing should be compared with microbiological evidence from molecular microbiological methods (MMM). See (Ibrahim *et al.*, 2018).

B.2.5 Significance of microbiological conditions

MIC is driven by microbiological metabolic activity that modifies the physicochemical conditions of both the environment and the metal surface at a local scale. Microorganisms can originate from the extracted hydrocarbon (indigenous in the reservoir) or can be introduced during operational processes, e.g. seawater injection, well work fluids, hydrotest water. Biofilms are created by the deposition of suspended microorganisms and other components (organic and inorganic solids) in a liquid onto a solid surface. Planktonic microorganisms refer to those that are suspended (free floating) in the fluid, while sessile microorganisms refer to those that form part of a biofilm attached to a surface.

Three key microbiological parameters that shall be considered when assessing MIC are as follows:

1) Activity

   Microbiological activity defines the metabolic state of microorganisms in a system. Three possible metabolic states can exist: active, inactive or dead. Active microorganisms have a potential to cause MIC due to their ongoing metabolic activities and growth. Inactive microorganisms are effectively dormant under given conditions resulting in no, or limited, metabolic activity (meaning that the potential for MIC to occur is low). However, these inactive microorganisms could become active over time if changes to operating or environmental conditions occur (leading to a higher potential for MIC). Finally, dead microorganisms are those that cannot become active again regardless of conditions, and contribute to MIC.

2) Diversity

   Microbiological diversity provides details on the taxonomy of the microorganisms present in a given system and helps to identify those microorganisms that could directly or indirectly affect MIC. Quantification of this parameter is often based on the relative proportion of each taxonomic group, e.g., phylum, genus, species, in a given population. A consortium of different microorganisms is believed to pose a greater threat of MIC.

3) Abundance

   Microbiological abundance or quantification defines the numbers of different types of microorganisms present in a given system. Quantification of microbiological abundance can be useful in assessing the effectiveness of MIC mitigation strategies.

B.2.6 Damage morphology

MIC takes place on internal pipeline surfaces under biofilm layers and can exhibit different damage morphologies. Although MIC is not characterized by a single morphology, a number of common damage features for MIC have been reported including:

1) cup-type hemispherical pits
2) craters (5-8 cm in diameter) surrounded by uncorroded material
3) striations/contour lines either in the pits and/or in the craters
4) tunnels at the end of the craters.

These features can be spaced widely apart or clustered in a specific area. Localized manifestations of both crevice corrosion and under deposit corrosion can also be associated with MIC. However, morphology alone is not a diagnostic for MIC, as pitting is a common trait for multiple mechanisms and the characteristics listed can be produced by abiotic corrosion mechanisms. The presence of corrosion features shall be considered in association with the presence of biofilms/deposits and the presence of byproducts related to the microorganisms found at the corrosion site. More information can be found in (Alabbas, 2017) and (Little and Lee, 2017).

B.3 Assessment, monitoring and mitigation

B.3.1 Corrosion management process

The corrosion management process for MIC is a systematic approach of three basic steps:

1) MIC threat assessment
2) identification and implementation of mitigation techniques/barriers
3) monitoring of the applied mitigation technique/barrier effectiveness.

These steps provide measurable data for key performance indicators (KPI). More information can be found at (Eckert and Skovhus, 2018), (Eckert *et al.*, 2015), (Skovhus and Eckert, 2014) and (Skovhus *et al.*, 2014).

B.3.2 Assessment of threats

B.3.2.1 Threats

The first step for MIC threat assessment is to break down the asset into corrosion circuits with similar operating conditions and/or fluid composition. Corrosion threats other than MIC may occur simultaneously or alternate over time and, for that reason, both the interaction between different corrosion threats such as CO_2, H_2S, O_2, and the influence of both abiotic and biotic mechanisms shall be considered. See (Eckert *et al.*, 2015).

The second step in MIC threat assessment involves gathering information and data as outlined in the following subsections.

B.3.2.2 Chemical analysis

Chemical analysis of process fluids and solids collected during regular inspection provides useful information that can be used to characterize both chemical and biological activity in the system. For MIC, chemical analyses of gas, liquid and solid phases is required to confirm functional activity of microorganisms such as nutrients and metabolites, and potential corrosion products either from MIC and/or abiotic mechanisms. Testing should focus on possible microbiological byproducts and energy sources in order to help link microbiological activity to chemical evidence.

Furthermore, chemical analysis is also critical for assessing whether observed degradation can be attributed to abiotic corrosion mechanisms as opposed to MIC. For example, if a high H_2S concentration is present and sulfide-producing microorganisms, i.e. sulfate reducing bacteria and archaea are absent, it is likely that the corrosion is driven by an abiotic H_2S corrosion. However, if the H_2S content is low/absent and SRB/SRA microorganisms are present, this indicates the possibility of MIC or MIC coupled with H_2S corrosion.

To characterize solid corrosion products, energy dispersive x-ray spectroscopy (EDS) and x-ray diffraction (XRD) are commonly used. These are often coupled with scanning electron microscopy (SEM) to determine the elemental composition (from EDS) and crystalline compounds (from XRD) of solid corrosion deposits. Gas chromatography (GC) and High-performance liquid chromatography (HPLC) are commonly used techniques that separate and quantify specific components and compounds in gas and liquid samples, respectively. Gas analysis of CO_2 and H_2S content in process fluids can also help identify and differentiate observed corrosion mechanisms (MIC versus abiotic corrosion).

Water quality tests also provide important information such as pH, dissolved O_2, chloride concentration, phosphorous related species, salinity/total dissolved solids (TDS) and concentration of volatile fatty acids (VFA). This information is useful for assessing both MIC and other possible abiotic corrosion mechanisms.

For further information, see (Juhler *et al.*, 2012), (Little and Lee, 2017), (Sharma *et al.*, 2017), (Skovhus and Eckert, 2017), and NACE TM0212 and NACE 3T199.

B.3.2.3 Microbiological analysis

Microbiological tests focus on assessing the diversity, abundance and activity of the microorganisms present at corroded areas and other locations without corrosion. When combined with chemical analyses, this data can be used to confirm or refute possible MIC mechanisms.

Microorganisms in oil and gas assets can be found in liquids, solids and on surfaces. As such, the concentration of microorganisms for each of these sample types is based on different sample units (SU): solids (cells per g), swab/surfaces (cells per cm^2) or liquids (cells per mL^{-1}). In terms of sample type, surface sampling of a biofilm by using swabs, corrosion coupons or biostuds is the ideal method for assessing microbiological parameters in biofilms, however, access to internal surfaces of assets such as piping, tanks may be challenging. If surface sampling is not possible, sampling of solids in the system could be the next best approach. Access to solids may be possible during routine inspection and cleaning operations, however, solids recovered from pigging are not representative of a single point on the pipeline because they accumulate and mix as the pig moves through the pipeline. Finally, liquid samples may also be used to characterize microorganisms/planktonic in the system, however, data from liquid samples are not representative of the microbiological diversity and abundance in the biofilm, where MIC can occur.

Once a sample is obtained, microbiological parameters can be assessed using a variety of test methods. Traditionally, culturing based techniques such as serial dilution/most probable number (MPN) tests and 'bug bottles' have been used to quantify activity and abundance. While these methods have been popular due to their ease of use and availability, they are limited to specific microbial functional groups, this because of culture media and incubation limitations, and may not accurately identify all MIC-related microorganisms present in a sample, i.e. microbiological diversity. In oil and gas pipeline systems with frequently changing conditions the limitations of culture media are even more pronounced.

Currently, the most advanced and reliable method to characterize microbiological samples is the use of molecular microbiological methods (MMM). MMM is a suite of technologies that are used to characterize the activity, diversity and abundance of microorganisms using enzymatic or genomics-based approaches.

The adenosine triphosphate (ATP) assay is a nucleotide-based test method that quantifies the number of active microorganisms in a given sample, microbiological activity, based on counts of ATP. The mass of ATP in picograms (10^{-12} grams) is further translated into microbial equivalents (ME), which usually vary from 10^3 to 10^{12} ME/SU, low to very high concentrations. ATP assays are a portable method that can be easily performed in the field. ATP assays quantify all active microorganisms present in a sample, irrespective of their functionality or metabolic pathway. Microorganisms must be active in order for MIC to occur.

Next generation sequencing (NGS) is a qualitative, DNA-based method that characterizes the diversity of the microorganisms found in a given sample, as a relative proportion of each taxonomic group. This test is run after DNA amplification, then microbiological taxonomic groups are identified by comparing their 16S rRNA genes to sequences in available databases. NGS is a laboratory-based method that can be used to identify the diversity of MIC-causing microorganisms in a sample.

Quantitative polymerase chain reaction (qPCR) is a DNA-based method that quantifies the number of specific microorganisms, or MFGs, per unit sample/microbiological abundance. The method uses primers/bio-chemical compounds to amplify targeted genes. qPCR assays are usually performed in a laboratory setting, however, portable units are now available. The abundance of MIC-causing microorganisms is a useful parameter in assessing the effectiveness of MIC mitigation approaches.

One important factor in MIC microbiological characterization is the use of proper sampling techniques. Sterile kits should be used to avoid microbiological contamination. Once a sample is obtained, it shall be analyzed in a timely manner, since changes in microbiology and degradation of samples can occur fairly rapidly. If analysis methods are not available locally, the sample shall be preserved and transported properly to an appropriate lab for assessment.

If sampling of internal surface deposits/biofilms is possible, it shall be handled in a way that the native biofilm condition is minimally altered by collection, storage or transportation. Inconsistency between sample collection and preservation methods used for different samples increases the probability of errors. Sample degradation can begin as soon as a pipeline is opened and exposed to air and contaminants. Without proper and consistent sample methods, changes to the sample weakens the validity of test results. The method of preservation for transportation, i.e. ice/cold pack, no ice/cooler, must also be considered. The laboratory performing the analysis should be consulted before sampling to determine the required methods and materials. For further guidance, see NACE TM0212, NACE TM0106 and NACE TM0194.

B.3.2.4 Operating conditions

Operating conditions of the asset such as flow rate, flow regime, temperature, pH and solids deposition can be obtained through real-time measurements, operating/inspection records, flow regime modeling and/or erosion potential calculations. This information is used to evaluate the influence of operating conditions on the corrosion mechanism, see Table B-2.

B.3.2.5 Corrosion data

The distribution and severity of corrosion, general and localized, can be identified based on past inspection data, in-line inspection results, failure investigations, and physical inspection during maintenance and pipe removal. As MIC can be an ongoing issue in systems, corrosion data provides a means to identify and track potential hotspots for future inspections based on past frequency.

Inspection not only confirms the presence and location of degradation, but also through reinspection its growth rate, which supports asset integrity management. Inspection data obtained from NDT can measure pitting depth and metal loss using a variety of techniques. NDT quantifies the distribution and severity of damage throughout the asset. Repeating wall thickness measurements in the same location over time, i.e., at a corrosion monitoring location - CML, is a useful indicator of corrosion rate on a localized basis. The location of CMLs is critical in order to obtain reliable information. Reliably predicting the location of isolated pitting is more difficult due to the stochastic nature of the damage distribution. More information can be found in (Skovhus *et al.*, 2017) and NACE 3T199.

B.3.2.6 Materials of construction

Materials information can be obtained from design drawings and records to help determine the susceptibility to corrosion threats. While MIC can occur in various metallic alloys, its degradation mechanisms and severity will depend on the specific microbiological, chemical and operational present in the system. In general, carbon steel is more susceptible to MIC than corrosion resistant alloys.

B.3.3 Mitigation strategies

A number of strategies are available to mitigate MIC related threats including mechanical cleaning/pigging, chemical treatment, adjustment of operational parameters, asset design alterations, and appropriate materials selection. The effectiveness of any of these mitigation approaches needs to be evaluated and adjusted based on regular monitoring and inspection. Often, selection of an appropriate mitigation strategy or combined strategies is based on input from a multidisciplinary team of experts including materials and process engineers, corrosion specialists, microbiologists, field operators, suppliers, and experts in risk management. The main approaches used to mitigate MIC in assets is described in the following sections.

B.3.3.1 Cleaning and pigging

Pigging, mechanical cleaning, flushing and sand jetting are mitigation methods used in pipelines, process vessels, dead legs and pressure vessels to control MIC. As MIC is biofilm-dependent, the removal of the biofilm layer is an effective method to control MIC. Flushing, when periodically used, is recommended for short pipeline sections or stagnant lines to avoid solids build up and biofilm development. However, agglomerated solids such as sand and scales may not be removed by flow alone and may require the use of solvents and/or surfactants to penetrate some deposits, or mechanical removal may be necessary. Physical cleaning and chemical treatment may be coupled, and biocides and flushing may be concurrently used, if needed, see (Eckert, 2016).

B.3.3.2 Chemical treatment

Biocides, corrosion inhibitors, surfactants, oxygen/H_2S scavengers, scale prevention/inhibitor chemicals, emulsion breakers, wax solvents, and flocculants are few of the possible chemical mitigation alternatives to support MIC management. When coupling different chemical treatments their compatibility should be considered, otherwise undesirable interactions may neutralize their effectiveness. Biocides and corrosion inhibitors are often used in conjunction to address both biotic and abiotic factors. However, they should not be applied together unless compatibility has been tested. NACE SP0499 and NACE 31205 discuss biocide selection and application for both seawater injection systems and oil and gas production. Commonly used biocides include tetrakis tydroxymethyl phosphonium sulphate (THPS) and glutaraldehyde. A common oxygen scavenger is sodium bisulfite, however, it reacts with glutaraldehyde.

A decrease in microbial activity numbers particularly in biofilms can help measure the efficiency of the mitigation strategy. Time kill tests are often used for initial screening of biocide contact time, and identification and concentration of biocides. The use of ineffective biocide application strategies and/or prolongated use of the same biocide may lead to the apparent emergence of 'resistant' microorganisms over time. In the presence of established deposits and in stagnant lines, biocides may not be effective as biofilm penetration will be limited. In that case, physical cleaning treatments to the extent possible, are preferred. See (Machuca and Salgar-Chaparro, 2019) and (Morris and Van Der Kraan, 2017) for further information.

B.3.3.3 Operational controls

Operational controls include maintaining a minimum velocity to keep water and solids entrained and preventing accumulation, use velocity to sweep pipelines or dead legs occasionally to remove water, improvement of fluid quality process parameters, such as reducing oil in water, i.e. produced water, to lower organic carbon levels or removing fluids from dead legs and adding preservative fluids, i.e. inhibitor. These are some of the operational controls used to minimize the probability of MIC.

B.3.3.4 Design based controls

Design based controls involve both appropriate material selection and asset design, e.g., reducing features that lead to water accumulation. General practices that help minimize corrosion may also have an effect on MIC, and act as barriers to degradation in general. To increase internal corrosion resistance two-part epoxies are sometimes used internally for piping that will not be pigged in addition to HDPE (high density polyethylene) linings. See NACE SP0169 for protective potential recommendations.

B.3.3.5 Material selection

In general, materials that possess resistance to corrosion may have also have a beneficial effect in reducing MIC. For example, corrosion resistant alloys (CRA) and stainless steels (SS) show greater resistance when compared to carbon steel (CS) due to greater stability and protective layer formation on surfaces. The addition of chromium, nickel or molybdenum have been shown to increase SS and CRA resistance against MIC. CS are often selected due to lower capital cost, but often require regular corrosion mitigation, which increases its life cycle operating costs. CRAs typically do not require continuous mitigation, but have a higher capital cost as compared to CS. While CRAs have higher resistance to general corrosion, they can also be susceptible to localized corrosion under certain conditions, which may lead to the need for additional mitigation.

Alloys with a high pitting resistance are also an option to reduce the potential for MIC. Pitting resistance equivalent number (PREN) is a parameter that measures the resistance of stainless steel against pitting in chloride environments, such as seawater. PREN is determined based on the content of chromium, molybdenum and nitrogen in the alloy, PREN = %Cr + 3.3 x %Mo + 16 x %N. Alloys with a PREN greater than 32 are generally believed to be more suitable for seawater applications.

For additional information on material selection, see (Eckert and Amend, 2017), (Little and Lee, 2007) and (Machuca, 2017).

B.3.4 Monitoring the threat and mitigation effectiveness

Monitoring is the third step in the cycle of corrosion management. Monitoring is used to determine the effectiveness of the barriers used to reduce corrosion and to provide awareness of changes in corrosion threats. Monitoring can produce short term and long-term measures. A short-term measure is the monitoring of bacteria populations in biofilms and their influence on pit initiation, while long term effectiveness could be measured using inspection to show that mitigation is controlling the corrosion damage due to biofilms. Note that although monitoring itself does not identify the corrosion mechanism, it can provide input for stipulating the corrosion rate for metal loss.

The use of molecular microbiological methods (MMM) as monitoring tools allows for:

1) monitoring both long- and short-term effects of mitigation on biofilms
2) monitoring changes in chemical effectiveness
3) the observation of shifts in microbiological populations.

Microbiological monitoring programs are generally based on:

1) water sampling from specific locations

2) pigging solid sampling
3) corrosion coupons.

They are complemented by proper training of staff for sampling and biocide strategy improvement.

Monitoring of MIC mitigation is optimally done by coupling the use of coupons and MMM to determine if the number, activity and/or diversity of microorganisms has changed along with trends in localized corrosion. Not only do monitoring points need to be determined, but also monitoring frequency and the methods to be used for coupon analysis. ATP of biofilm/sessile samples can be measured, for example, quarterly when no active microbiological corrosion is being experienced and monthly when active MIC is experienced. Coupons may be exposed at the monitoring sites for at least 90 to 120 days before analyzing using ATP, qPCR, NGS and metal loss/pitting rates. As MIC is a localized mechanism, measuring weight loss is not meaningful for identifying MIC on coupons. Pit depth/width and pit density on extended-analysis (EA) coupons should be quantified using optical microscopy, light interferometry, or laser profilometry. Coupling microbiological numbers and activity with pitting corrosion is a sound approach when selecting or optimizing MIC mitigation methods.

Biofilm analysis can be done through the examination of biostuds, corrosion coupons, EA coupons and, to a lesser degree, using pig debris. Inappropriate coupon placement may lead to erroneous data. Coupons are usually placed either into the oil or water phase, into a sidestream device (where the flow rate or shear stress can be controlled) or upstream and downstream of the biocide treatment.

More information can be found at (De Paula and Keasler, 2017), (Skovhus *et al.*, 2017), and NACE SP0775 and NACE 3T199.

B.4 Assessing probability of failure for microbiologically influenced corrosion

Due to the complexity of MIC mechanisms and the wide range of parameters involved, there is no current model that can precisely and accurately predict the initiation and growth of MIC for all oil and gas field conditions. Instead, in a similar fashion to the approach developed by (Skovhus *et al.*, 2018), the Probability of Failure due to MIC (PoF_{MIC}) can be determined using a two-step, qualitative approach as follows:

Step 1 - In order to determine the Probability of Failure due to MIC for a given asset or corrosion circuit, the flowchart in Figure B-2 can be utilized. This approach looks at specific microbiological datasets, chemical datasets and operational information outlined in Table B-2 to simply identify whether the potential for MIC is negligible, i.e. $PoF_{MIC} = 10^{-5}$ per year, or non-negligible, i.e. $PoF_{MIC} > 10^{-5}$ per year. The approach is built around the concept that a number of specific conditions are required for MIC to become a threat.

Step 2 - If the potential for MIC is non-negligible, further refinement of the PoF_{MIC} value from 10^{-5} to $>10^{-2}$ per year can be accomplished by using Table 3-1. The necessary input for Table 3-1 can be provided by trends from MIC related corrosion data, current/past inspection results, failure or maintenance reports, subject matter experts, and review by informed stakeholders, such as materials and integrity engineers, operators, inspectors, suppliers and service providers.

This methodology provides a systematic, yet flexible approach to PoF determination for MIC related threats.

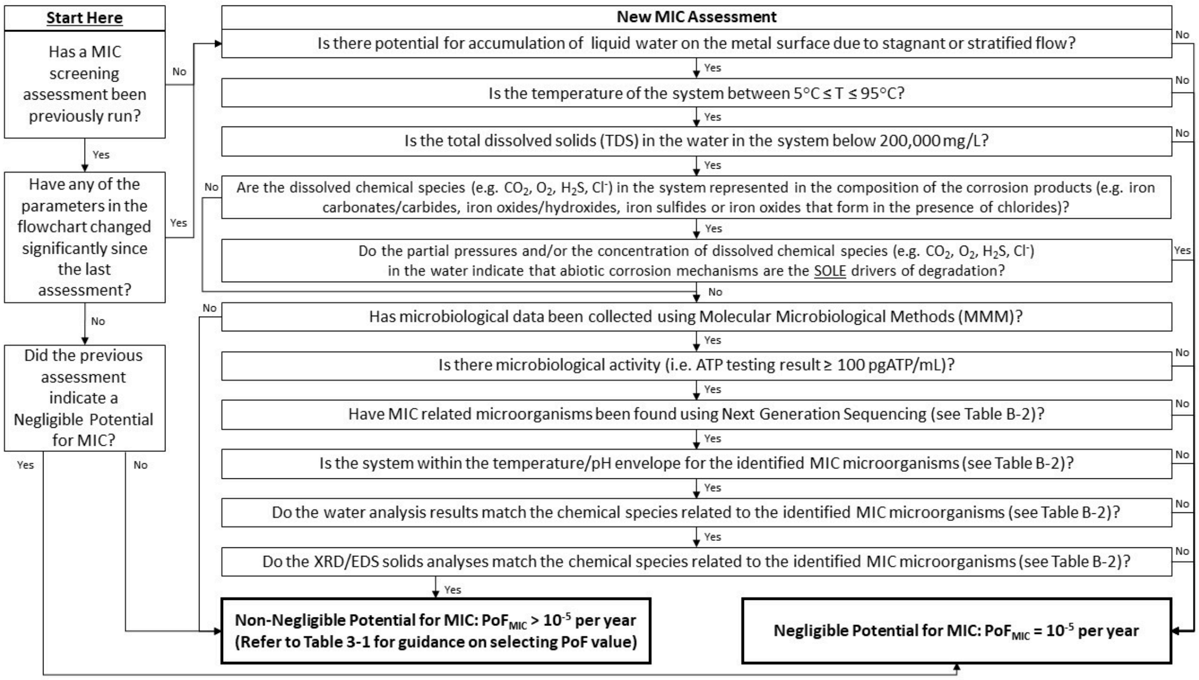

Figure B-2 Flowchart to assess probability of failure due to MIC (PoF_{MIC})

B.5 Examples of microbiologically influenced corrosion in oil and gas systems

MIC can occur in a variety of asset types and locations in oil and gas systems. Some examples of MIC case studies are provided in this section. Cases 1 and 2 can be found in detail in (Alabbas, 2017), while Case 3 can be found in (Skovhus *et al.*, 2017).

Case study 1 - MIC was found in outlet piping in a high-pressure wet crude production trap at a gas oil separation plant. Leaks occurred at multiple points after 2 years of operation. The piping was made of carbon steel, and the fluid was crude oil with 1.2% H_2S and 3.5% water cut, at a temperature range from 35°C to 46°C. XRD results from corrosion deposits showed the presence of iron oxide, iron hydroxide, chloride related corrosion products, iron sulfide, iron carbonate and elemental sulfur in and around the pits. qPCR identified SRB, acid producing bacteria (APB), nitrate reducing bacteria (NRB) and MA with abundance numbers ranging from 10^3 to 10^7 cells/g.

Case study 2 - Heat exchangers in a seawater cooling system experienced a number of unexpected failures due to MIC. The affected tubes came from four process units:

1) secondary water cooler
2) naphtha rundown cooler
3) drier overhead pre-condenser for kerosene hydrodesulphurization
4) lube oil cooler.

The tube side fluid at all sites was seawater at around 40°C. The shell side fluid was different at each site: water at 85°C at site 'a', naphtha at 57°C at site 'b', kerosene at 96°C at site 'c', and lube oil at 58°C at site 'd'. All the tubes were made of brass except for site 'c' which was constructed from a copper-nickel alloy. Deposits were sampled at the pitting corrosion sites, and qPCR identified iron oxidizing bacteria (IOB) and APB with abundance numbers varying from 10^3 to 10^6 cells/g.

Case Study 3 - Corrosion was found at a multiphase oil inlet during regular inspection of a topside crude oil production separator. The inlet piping was constructed using carbon-manganese steel, and the system handled crude oil at a temperature of 60°C and a pH of 6-7. The flow rate was relatively low at approximately 1 m/s. Inspection showed that the morphology of the corrosion defects consisted of both general wall loss and localized pitting. For a number of years, serial dilution of fluid samples was used to monitor the system for microorganisms. Low concentrations of planktonic SRB, MPN of 10^0 to 10^1 cells/ml, were typically found in the water phase, and due to the low numbers, no microbiological mitigation was implemented, i.e. biocide treatment. After 13 years of using culturing methods, more modern qPCR analyses were performed on solid deposits taken from corrosion coupons placed in the system. Contrary to the previous MPN culture-based test results, the qPCR tests found significant numbers of SRB, SRA and MA present in the system, 10^6, 10^7, 10^8 cells/g, respectively. XRD analysis from the corrosion deposits was also performed and found siderite, mackinawite, quartz, akaganeite and lepidocrocite. Due to this expanded understanding of both the microbiological and chemical parameters, the corrosion was finally attributed to a combination of both uniform CO_2 corrosion, i.e. abiotic and localized MIC, i.e biotic.

APPENDIX C FATIGUE ASSESSMENT

C.1 External mechanical damage

Mechanical damage caused by vibration, ship or platform movement, flow effects, or other sources, may cause fatigue crack growth and fracture. For piping systems, the damage is often located in local hotspots, such as welded connections, branches, clamps, or vessel nozzles, where the design or fabrication gives a high stress concentration factor, and restraint may also increase loading locally.

Fatigue in piping systems caused by high frequency vibrations (such as from reciprocating machinery) is expected to propagate rapidly to failure once a crack is initiated, and is therefore not readily amenable to monitoring and control by inspection. In such situations, it is recommended that the local vibration amplitude and the local stresses are measured, rather than calculating the crack growth.

Where the source of vibration has a low frequency, such as ship motion, then inspection may be used to measure the development of damage.

C.2 Introduction

The PoF due to fatigue and fracture, caused by high- and low-frequency fatigue is assessed for a given component, based on its geometry, dimensions, materials of construction, loading and other operational conditions.

Note:

This document differentiates between high-frequency and low-frequency fatigue and not high and low cycle fatigue.

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C.2.1 Fatigue

What distinguishes fatigue from other failure mechanisms is the uncertainty with respect to cumulative damage. In a piping system with thin wall thickness and defect-free welds, subject to high frequency stress ranges, virtually all of the fatigue life is spent in the so-called initiation phase, where any direct measurement of the progress is impossible. In the subsequent crack growth phase, the time for the crack to travel through the thickness may be short. Hence, for this case of fatigue, it is not feasible to measure the remaining life, as one can do, e.g. for through thickness corrosion, where techniques of measurement exist. Therefore, high frequency fatigue is classified as a 'susceptibility' type degradation mechanism.

However, various techniques are in existence to detect and measure the size of fatigue cracks that are growing, provided they are below a certain depth. Due to the difficulty in measuring fatigue crack initiation, one has to resort to indirect measurement, in combination with evaluation of contributing factors.

Indirect measurement of fatigue is obtained by measurement of stress ranges subjected to the structural part in question. With the fatigue-life diagram, an S-N curve, a graphical representation of the dependence of fatigue life, N, on fatigue strength, S, as reference, the effect of stress range on fatigue life is evident. Stress concentration, caused by geometrical shapes, both locally and globally, contribute to fatigue as they locally amplify the stress ranges experienced by the material. It is possible to distinguish and quantify such geometrical factors with respect to inspection methodology.

Due to the long time it takes for crack initiation in a defect-free section compared to that for crack growth, it is crucial that the pipe welds are defect-free to ensure adequate system fatigue life. If welding flaws are present, the benefit of a long initiation phase may be lost and the fatigue lifetime of the joint very much reduced. Such flaws may be introduced during the construction phase, as a result of substandard welding and inspection.

C.2.2 High frequency load ranges

With load ranges acting on components at more than 10^7 cycles per year, or approximately 0.3 Hz, cracks may grow rapidly to a critical crack size. The time interval between the crack reaching a size where its probability of detection (PoD) by inspection is high, and the crack reaching a critical size where leakage or unstable failure occurs is very short, and can be in the order of weeks. Fracture mechanics crack growth analyses are of little use and high frequency fatigue can be modelled after the susceptibility model, where there is either an intact pressure boundary, or an imminent failure. So measuring or monitoring the crack size by inspection will not be useful in determining high frequency fatigue. The approach used for other susceptibility models in the RP is adopted, where measuring the controlling parameters is recommended in place of NDT.

The physically measurable quantities of interest are the vibration velocities, strains in the piping, and any flaw sizes in welds. The strain can further be converted to stress and compared to appropriate S-N curves.

C.2.3 Low frequency fatigue

Low frequency cyclic loading, such as that caused by ship or platform motions, infers a crack growth duration that is sufficiently long to allow monitoring by NDT. An approach using S-N curves or fracture mechanics analyses can be applied to determine when to inspect.

C.2.4 Practical assessment of fatigue

A guideline for a simplified assessment of potentially fatigue-prone welds is presented in this section. As the problem of fatigue cracking is generally concentrated at welded joints, those are therefore the focus of this work. Other joining methods, such as adhesive or bolted joints, are not considered here. The guideline covers how to distinguish fatigue-prone welded joints of inadequate quality from welded joints of adequate quality, by simple and fast visual examination methods. The guideline also covers how remedial work shall be done to make inadequate welded joints adequate with respect to fatigue susceptibility.

The measurement and analysis of fluctuating stress ranges are also included.

This simplified fatigue evaluation guideline is a 'go/no-go' type of assessment, and it has been a clear goal that the assessment of the welded joints shall be quick and not require extensive training or equipment.

For the purpose of the guideline, the categorisation of welds as adequate or inadequate has been introduced. It is recommended that risk-based methods be used for ranking and to determine the effort should be concentrated.

C.3 Quantification of probability of failure in thin-walled pipe

It is not feasible to adequately quantify a PoF in a thin-walled piping system subject to high frequency fluctuating stresses. The long crack initiation phase, which determines the actual fatigue life of the structure, is difficult to measure or predict, compared to the short time to failure once a crack is present. The time to failure after crack initiation can be seen in Figure C-1. Fracture mechanics calculations have been used to demonstrate potential crack depth as a function of time under several loading conditions. These curves show that by the time the defect is of a size where the PoD suggests that the defect might be detected, i.e. of the order of 2 to 4 mm, the remaining time to failure is in the order of weeks or days. For this reason, the degradation mechanism model used for high frequency fatigue is the 'susceptibility' model.

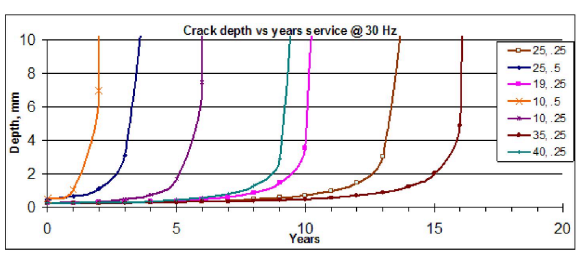

Figure C-1 Fatigue crack depth as a function of time for several stress ranges and initial defect sizes

Whether fatigue failure occurs is governed by the measurable stress ranges and by the contributing geometrical factors. It should be safe to say that the latter are the cause of the majority of fatigue failures experienced in hydrocarbon processing plants to date.

The typical conditions that apply when fatigue failure is possible are moderate stresses, combined with contributing geometrical factors, and flaws or defects.

High stress ranges will cause overload failures rather than fatigue failures. Overload failures, and low-cycle fatigue failures, are generally not influenced by geometrical stress amplifiers. Hence, the geometrical contributing factors are the most important to address in the case of fatigue failures that do not occur immediately.

C.4 S-N curves

The assessment assumes that an adequate S-N curve is available for the material and joint configuration in question, which is unlikely if the pipe system is of a corrosion resistant alloy. Previous test work by DNV indicates that such materials render the pipes more fatigue resistant than equivalent geometries in carbon steel.

However, the use of an overly conservative S-N curve may initiate unnecessary remedial work that may transfer or create new problems. DNV recommends that, where the use of overly conservative S-N data is likely to lead to excessive joint remedial work, the missing S-N data should be obtained by a method analogous to the DNV test work referred to above, at least as limited verification points, to indicate the presence of the relevant S-N curve.

If all stress ranges are below the range corresponding to 10^7 cycles, then fatigue need not be considered. For a stress range spectrum including ranges above this value, stress ranges corresponding to less than 2×10^7 cycles are considered not to contribute to fatigue in a Miner-Palmgren type of cumulative assessment. The guideline does not consider cumulative assessments of stress spectra where different stress ranges contribute differently to fatigue crack initiation. The simplified approach of this guideline is to state that all stress ranges should be below the limit for contribution to fatigue crack initiation.

C.5 Assessment for fatigue

The guideline below introduces and describes the assessment cycle, which is given as a flow chart , see Figure C-2, that shows the required sequence of prioritised actions.

C.5.1 Application of the guideline

This guideline is a tool to quickly identify and perform remedial work on welds that are potentially fatigue-prone by surface crack initiation and growth.

It does not cover measures against failure due to insufficient material thickness.

Guidance note:

- Potentially fatigue-prone welds are typically welds that join an oscillating mass to a firm structure, such as valves on branch pipes fitted to main flow pipes.
- Insufficient material thickness may result in overload failure or low-cycle fatigue failure. These failure modes are generally not sensitive to inadequacy as defined herein.
- This guideline is based on distinction between welded joints that are either:
  - adequate
  - inadequate.

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In the case of inadequate welds that are subjected to fatigue loading, joint remedial work should be done if failure is unacceptable.

C.5.2 Definitions

The terms defined in Table C-1 are used in this guideline.

Table C-1 Terms and definitions

Term	*Definition*
adequate joint	welded joint that has the sufficient smoothness and manufactured surface quality to withstand fatigue loading without crack initiation from the surface
assessment cycle	complete work process for each critical area
checkpoints	defined areas of the welds in which to concentrate the close visual inspection
close visual inspection	visual inspection for surface defects for selected, individual, welded joints
criteria	criteria apply to undercut, bulge and grinding marks, which are factors that increase the likelihood of fatigue crack initiation from the surface
critical area	area where the CoF is unacceptable
direction of viewing	how to orientate the view to get the best ability to detect criteria
evaluation	comparing the occurring fluctuating stresses with the appropriate S-N curve
general visual inspection	survey to get the overview of the critical area to know where to prioritise the close inspections within that critical area
inadequate joint	welded joint that does not have the sufficient smoothness and manufactured surface quality to withstand fatigue loading without crack initiation from the surface
joint remedial work	modifying the appearance, i.e. geometry and surface of the weld in order to change its condition from inadequate to adequate quality
ranking (1)	in order to determine where to start the work, critical areas are ranked with respect to CoF
ranking (2)	in order to prioritise within a critical area, joints are ranked based on the severity of the configuration before close inspections are carried out
types of welded connections	based on configuration, the connections are of either type A, B or C, see [C.5.3.3]
visual examination	using the human eye to distinguish an inadequate welded joint from an adequate welded joint based on criteria

C.5.3 The assessment cycle

The assessment cycle is shown graphically in Figure C-2. Consider whether it is most effective to carry out all ranking and inspection planning activities before beginning inspection.

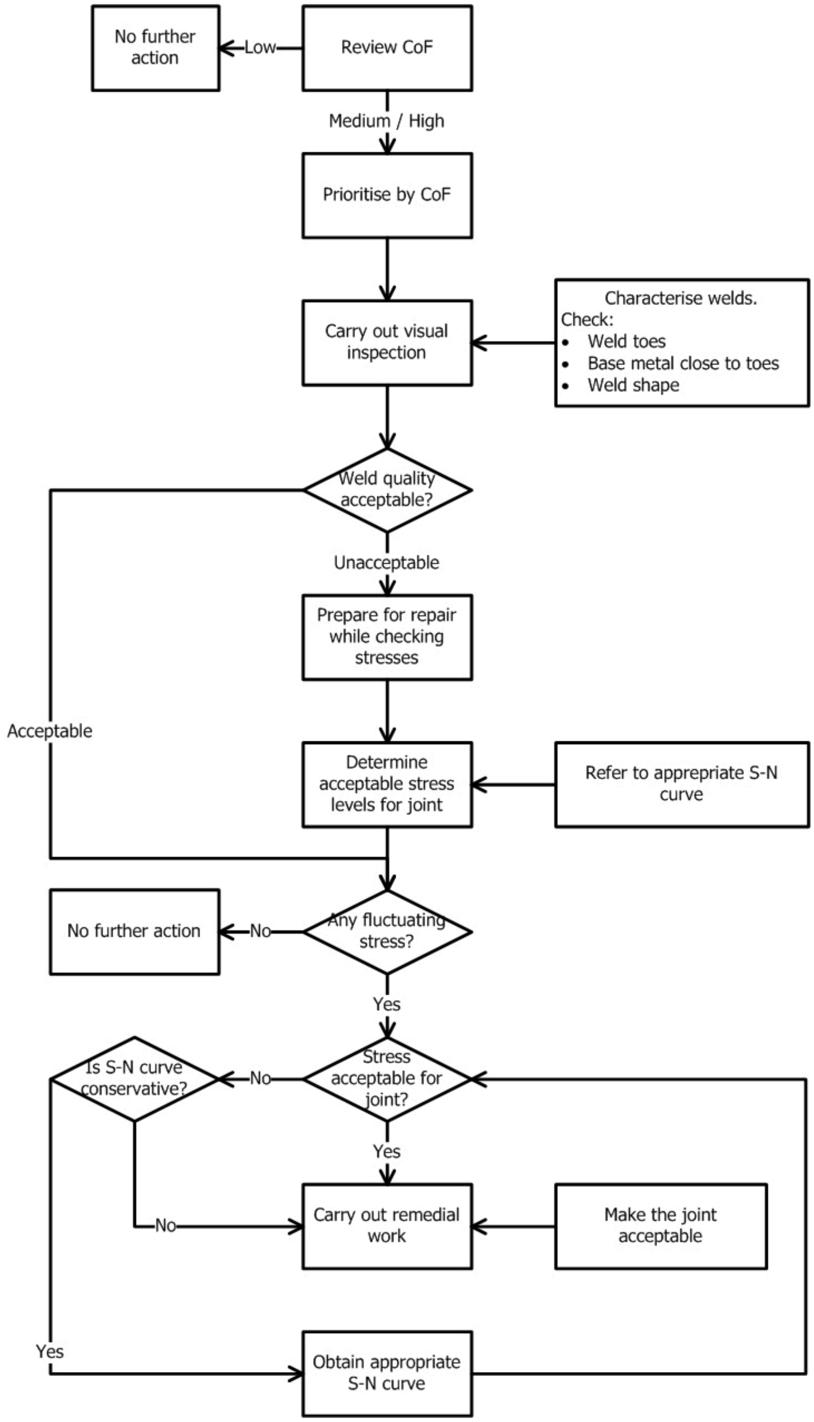

Figure C-2 The assessment cycle for a critical area

C.5.3.1 General inspection

Identify the potentially susceptible areas of the process plant, and rank them in order of severity with respect to consequence.

Start with the area with the most severe consequence, and perform a GVI. As part of the inspection, check the presence of welded branches on the P&ID and isometric diagrams, and highlight the welds of least favourable profile on the piping diagrams.

Make a general ranking of the connections with respect to mass size and branch pipe size.

Guidance note:

- For the connection weld joint of a branch pipe with an attached mass:
  - a heavy mass is more susceptible than a light mass
  - a small diameter is more susceptible than a large diameter.
- A small diameter branch pipe connected to a large diameter main pipe is more susceptible than a large diameter branch pipe to a small diameter main pipe.

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C.5.3.2 Close inspection

In order to determine whether a joint is adequate or inadequate for fatigue service, close inspections shall be carried out for each critical area.

Start with the most severe combination of mass to branch size, and branch size to main pipe size, and perform the first close inspection here.

Guidance note:

If there are few joints, it may be more efficient to skip this ranking and just start the close inspections immediately after the survey inspection.

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C.5.3.3 Types of welded connections

A. Straight pipe-to-pipe welds

B. Pipe-to-pipe branch connections

C. Welded pipe supports

C.5.3.4 Checkpoints - all connections

I. Weld toe

II. Base metal close to weld toe

III. Shape of weld

Additional check points for connection C:

IV. Corners

C.5.3.5 Criteria

I. No visual undercut permissible

II. No grinding marks at weld toe with other orientation than perpendicular to the weld toe

III. No bulge on weld material to give angle above 45° at the weld toe

IV. Special attention needed

C.5.3.6 Method

Perform a visual examination of each weld at the checkpoints shown in Figure C-3 to Figure C-8. Use only visual methods, and look from different angles to get the best view for the defect in question. Create a shade or apply a torch to reduce or increase the amount of light to get a good view. Use a mirror the access is restricted to all sides.

In summary:

— If this visual inspection does not detect any defects described in this section, the weld joint is deemed adequate.
— The checkpoints are shown in Figure C-3 to Figure C-8.
— Due to the shape of the corners, inspection viewing shall be carried out from both sides for all four corners.
— All of the weld shall be inspected.

C.5.3.7 Direction of viewing

This screening method is based on fast, visual inspection. The correct direction of viewing must be applied to get the right results. The following viewing directions shall be applied:

I.	Weld toe undercut	Direction of viewing parallel to weld toe.
II.	Pipe surface condition	Direction of viewing perpendicular to surface.
III.	Weld cap profile	Direction of viewing parallel to weld toe and weld.
IV.	Corners	Same as I, II and III, but in two directions: — Parallel to support. — Perpendicular to support.

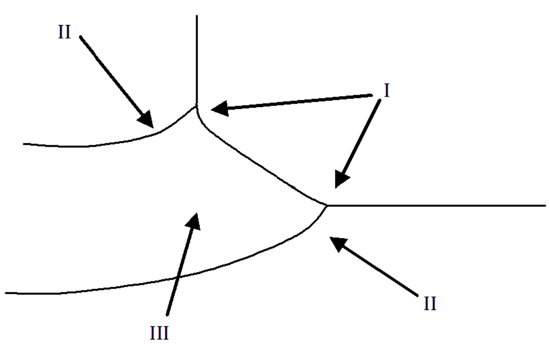

Figure C-3 Inspection points for branch weld

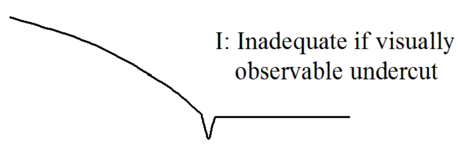

Figure C-4 Weld toe undercut

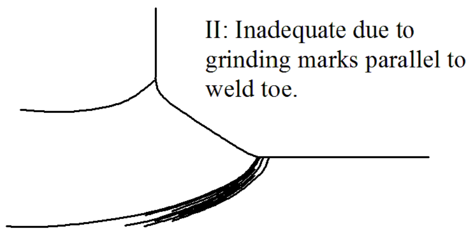

Figure C-5 Ground base metal at weld toe

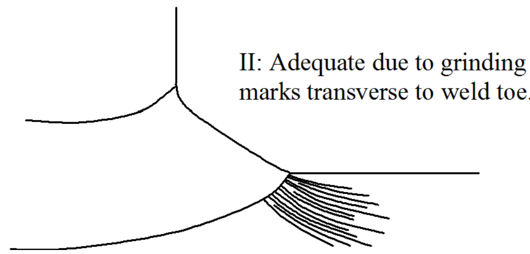

Figure C-6 Ground base metal at weld toe

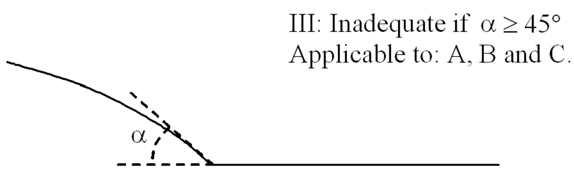

Figure C-7 Weld metal cap profile

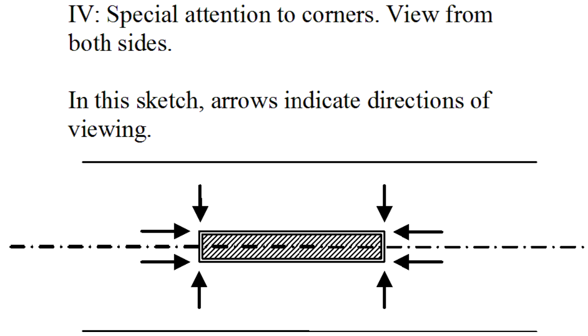

Figure C-8 Special attention to corners on welded supports

C.5.4 Measurement of stresses

In order to evaluate whether fatigue may occur, the applied stress ranges shall be measured.

Important notice:

— Due to the stress amplification inadequate geometry can lead to, any inadequate welds should be modified to an adequate condition before measuring stresses.
— An appropriate transducer shall be used since visual observation of vibration levels may be misleading .

Guidance note:

If surface temperature permits, handheld frictional strain gauges can be used with good results. Alternatively, clip-on extensometers may be used, as well as permanently applied strain gauges.

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C.5.4.1 Location of measurement

Stresses shall be measured 15 mm away from the weld toe.

Guidance note:

— Any other measurement location may impair the results.
— The gauge length of the transducer should be orientated perpendicular to the weld toe.
— Measurement closer than 10 mm, or on or across the weld itself, will not provide results that can be used.
— The measurements should be made on both sides of the weld, or at the side of the weld that is considered of importance. Several directions shall be measured as applicable.

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C.5.5 S-N curve selection

Measured stress levels shall be compared to an acceptance criterion.

The acceptance criterion for permissible stress range is derived from the appropriate S-N curve, at 10^7 cycles, see Figure C-9.

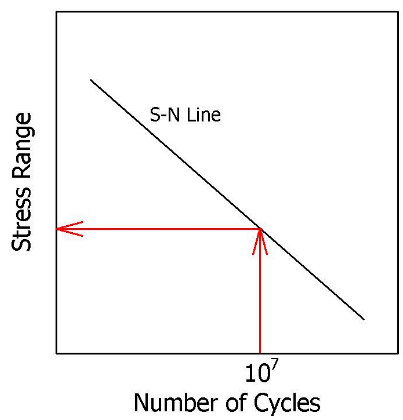

Figure C-9 Determining the highest permissible stress range from the S-N diagram

Evaluation:

— If an S-N curve is available for the actual material and geometry in question, then it should be used.
— If such an applicable S-N curve is not available, select a fatigue curve from DNV-RP-C203, based on principal geometry and loading picture.

Important notice:

— Ensure that stress concentration from weld geometry is covered by the fatigue curve.
— Additional stress concentration from global geometry/configuration shall be taken into account when comparing the measured stress level to the S-N curve.
— If measured stresses are higher than the acceptance criterion, stresses shall be reduced, or if possible a more appropriate S-N curve for the material and geometry in question should be used for a re-assessment.

C.5.6 Joint remedial work

Any inadequate joint shall be upgraded to adequate quality.

Important notice:

— Joint remedial work shall be carried out as described either herein, or in instructions provided, such as welding procedures, repair procedures, etc.
— No flame-cutting or other unsolicited methods are permissible.
— Due to the uncertain nature of re-supporting, joint remedial work shall always be carried out if fluctuating stresses are present.

Guidance note:

— Introducing additional supports without performing joint remedial work is ineffective. It may not solve the problem, and the likelihood of new problems is high.
— If stresses are above the acceptance criterion, then additional supporting work or other modifications should be carried out in addition to joint remedial work.
— If such additional work is performed, the assessment cycle shall be repeated for the affected area.
— Joint remedial work is categorised by the defects the work is remedy for.

I. Undercut at weld toe.

II. Grinding marks in parallel with the weld toe.

III. Excessive weld cap profile.

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C.5.6.1 Undercut removal

Visually observable undercut is removed by grinding or dressing. This process shall leave all marks transverse to the weld toe. See [C.5.6.1] for illustration of weld toe undercut removal.

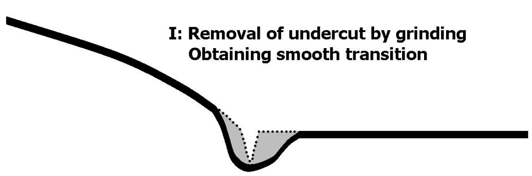

Figure C-10 Weld toe undercut removal

Guidance note:

If repair grinding marks are not left perpendicular to the weld toe, the situation may be worse after the repair.

the undercut must not exceed 10% of the initial wall thickness after grinding or dressing.

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C.5.6.2 Removal of grinding marks in parallel with the weld toe

Grinding marks in parallel with the weld toe shall be removed by grinding or dressing, and leave the marks transverse to the weld toe.

C.5.6.3 Excessive weld cap profile

Excessive weld cap material shall be removed by grinding, leaving the finishing grinding marks transverse to the orientation of the weld.

Guidance note:

If there is insufficient weld material present to perform the required joint remedial work, then more weld material shall be added in accordance with the appropriate welding procedure.

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APPENDIX D USE OF INSPECTION AND MONITORING

D.1 Introduction

The RBI assessment is used to generate an inspection plan at the desired level of detail. Once the probabilities and consequences of failures are evaluated, and the risks are established, it is necessary to decide whether or not to inspect, when to inspect and how much to inspect. The assessments allow the following parameters to be estimated for each part:

— Degradation mechanism, and hence possible inspection methods, morphology of damage and the expected damage extent or size.
— When to apply the inspection, i.e. the time when the risk limit is crossed. For the time-dependent rate models, inspection should be scheduled such that the risk limit is not exceeded, with adequate time allowed for keeping track of degradation processes and for carrying out any remedial action. The non-time-dependent mechanisms are not considered suitable for direct control by inspection, but may for instance require monitoring certain process parameters or GVI to check that any premises used in the analysis remain valid, such as good coating.

D.2 Development of inspection plan

The inspection plan should contain the following information as a minimum:

— part identification
— drawing references
— expected degradation mechanism/morphology, location and extent
— monitoring strategies for expected degradation
— inspection location / inspection point
— inspection method
— time to inspect
— reporting
— evaluation
— updates and corrections.

Reference should also be made to minimum operator qualifications, equipment type and calibration requirements, inspection procedure to be used, applicable standards, and other quality-related information.

When carrying out the final inspection planning, the following points should also be considered:

— A component may be subject to different degradation mechanisms that are expected to reach their risk limits at different times. The inspection schedule should take into account these differences by rationalising the timings into suitable groups to avoid otherwise frequent activities on the same components.
— The operator’s policy and legislation regulating the operation of a field may set specific requirements with respect to inspection. These requirements may be in the form of:
    — how often to inspect certain types of equipment
    — acceptable condition after an inspection, i.e. wall thickness limits.
— Access requirements.
— The need for shutdown of the process during inspection.
— Requirements for detailed inspection drawings.
— Reporting format and reporting limits.

D.3 Expected degradation mechanisms, morphology, location and extent

Check the expected degradation mechanisms for the component in question and the damage location.

— Damage type and expected damage location, e.g. top/bottom, welds, components.
— Internal/external damage.
— Variation of degradation with time.

D.4 Monitoring strategies for expected degradation

Different types of monitoring strategies can be implemented to address expected degradation due to defined mechanisms. Monitoring strategies will produce monitoring data regarding degradation rates or key indicators for risk change, such as process changes.

Guidance note:

— Monitoring probes and coupons are generally not intended to provide quantitative degradation rates, but rather to monitor and ensure that the rates are within specified limits. They are also used to monitor inhibitor performance.
— Monitoring of key process parameters that control the rate or onset of degradation can be used to detect the changes in operating conditions, operational practices or reservoir characteristics.
— Different types of degradation control strategies can be implemented to prevent the expected degradation due to defined mechanisms. Control strategies and the effectiveness of these will be assessed in the PoF-analysis.
— Injection of corrosion inhibitor is a typical strategy for control of degradation in offshore processing management.
— Inspection measures the extent of degradation and allows for comparison of the condition revealed by inspection to the design premises. Follow-up on deviations from design premises on operational conditions is a part of RBI planning.

---e-n-d---o-f---g-u-i-d-a-n-c-e---n-o-t-e---

D.5 Inspection location and inspection point

A hot spot is a defined part of the inspection object or area where damage is most likely to occur. The hot spot is then a specified area where the inspection effort should be applied, using e.g. CVI or NDT inspection techniques. GVI, and to some extent CVI, techniques will call for a wider definition of hot spots related to damage. The definitions of hot spots will give guidance to the selection of inspection points.

D.6 Inspection method

A number of intrusive and non-intrusive methods have been developed to inspect pipes and other static equipment and take geometric measurements, e.g. diameter, wall thickness, metal loss, crack and other defects.

Table D-1 has been developed as an aid to select inspection methods and coverage based on the results from an RBI analysis. The subsections below describe the contents of different columns of the table.

The use of the table is valid under the following assumptions:

— Where different methods are suggested for the same degradation mechanism, the methods should be considered as alternatives to each other.
— The inspection methods are used within their recognised limitations with respect to dimensions and materials of construction for the component subject to inspection.
— Inspection is carried out according to qualified procedures and by qualified personnel.
— All indications of defects found during an inspection are followed up by necessary actions to determine the defect size and need for increase in the extent of inspection.
— When identifying a limited selection of hot spots, it should be recognised that some of the degradation mechanisms will have different PoF for the different types of hot spots listed. The focus should be on the

hot spots that are judged to have the highest PoF, but samples of hot spots with a lower PoF should be included for completeness.

— No differentiation is made between the various methods listed for a damage mechanism with respect to PoD in this table, i.e. all methods have been treated as having a PoD of 1 if they have been found suitable to detect the expected damage. Further differentiation in inspection efficiency for the different methods can be made with reference to PoD curves.

D.6.1 Damage mechanism

The first column provides guidance for the expected damage mechanism. The details about these mechanisms can be found in Sec.5 and App.C.

D.6.2 Damage description

The second column of the table summarises the outcome of the damage mechanism. It also gives guidance for the location of hot spots.

D.6.3 Inspection method

The third column of the table recommends the most suitable inspection method for detecting and measuring the damage caused by a particular damage mechanism.

The following abbreviations have been used:

GVI	general visual inspection
CVI	close visual inspection
ET	eddy current testing
ET-remote	remote field eddy current
MT	magnetic particle inspection
PT	dye penetration testing
RT	radiographic testing
RT-RTR	real time radiography
UT	ultrasonic testing
UT-long range	creeping/head wave inspection method
UT-tubes	internal rotating inspection system, ultrasonic.

Guidance note:

— Results from different inspection methods may not be handled in the same data set.

— Make sure the method, procedure, calibration, etc. are the same.

— Any error in the inspection method should be included in the estimation of corrosion rates.

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D.6.4 Inspection effectiveness

The inspection effectiveness that is required depends upon the requirements of inspection. In this appendix the following inspection effectiveness categories have been defined based upon the examination of hot spots or suspect areas.

— Highly effective inspection is used to determine the actual state of degradation when degradation activity is determined. The inspection method will correctly identify the actual damage state in nearly every case.
— Effective inspection is used to determine the amount of degradation activity when degradation activity is expected. The inspection method will identify the actual degradation with an uncertainty given by the number of repeated inspections of the same system.
— Fairly effective inspection is used to determine if degradation activity is occurring when no significant degradation is expected. The inspection method may give indications if unexpected degradation activity occurs.

Columns four to six can be used as a guidance for the inspection engineer to determine the percentages of hot spots that need to be inspected in order to achieve the desired effectiveness of the inspection.

Guidance note:

— The effect of PoD for the inspection method should be considered because a small damage may cause the risk to exceed the limit, yet such damage may not be reliably detected by equipment having low PoD. In such an instance, other risk management methods should be considered.
— In most cases it is recommended to use the category 'effective inspection' in inspection planning. 'Effective inspection' will contribute to the requested reduction in the uncertainty of the degradation rate / damage state. A reduced uncertainty in the damage state will contribute to reduce the risk related to degradation damage.

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D.6.5 Selection process

The PoF evaluation gives an estimation of likely degradation mechanisms, together with their morphology and the data required to estimate the resulting PoF. This information can be used to optimise the inspection procedures and techniques, and to select which data should be recorded so that the RBI analysis can be updated after an inspection.

The choice of inspection method is based on optimising several factors that characterise each technique:

— Confidence in detecting the expected damage state.
— Cost of the technique, including manpower and equipment.
— Extent of maintenance support required, e.g. scaffolding, process shutdown, opening of equipment.

Normally, the technique that gives the greatest effectiveness in detection should be chosen, see [D.6.4]. However, it may be more cost-effective to apply a less efficient technique more frequently, and the choice of technique can be based on the following simple cost-benefit analysis:

1) See Table D-1 for the confidence level for the technique chosen.
2) Estimate the cost of carrying out the inspection using the chosen technique.
3) Determine the PoD for the mean extent of damage expected at the inspection time.
4) Select the technique with the highest value of:

$$\frac{PoD}{(Cost \times Confidence\ CoV)}$$

The above method is applicable to the first inspection scheduled after the RBI analysis. Prediction of the next inspection timing is estimated once the inspection has been performed, and the above steps repeated using the inspection results.

Note that the inspection procedure should include strict requirements regarding reporting inspection results, so that the data reported is relevant, and can be readily used, to update the RBI analyses and plan the next inspection.

D.7 Time to inspect

The time to inspect is discussed in detail in Sec.7.

D.8 Evaluation

If internal or external corrosion is detected, then fixed key points at a number of selected locations should be built to monitor the corrosion growth at a frequency decided by the corrosion and inspection engineers, unless it can not be justified within the remaining economic life of the item.

NDT measurements can also be taken on existing corrosion monitoring points to substantiate corrosion coupon readings. This method should be used in all locations where coupon results indicate corrosion in excess of the corrosion design criteria.

Inspection data evaluation should include as a minimum:

— assessment of inspection findings
— estimation of existing minimum wall thickness
— estimation of corrosion rate
— remnant life calculations
— maximum allowable working pressure calculations
— establishment of retiring thickness
— conclusions on integrity status
— recommendations as to further action.

The overall evaluation of the integrity status as a result of inspection activity should be carried out and the findings of the inspection, including the evaluations, shall be verified.

The effectiveness of the inspection activities should be assessed periodically where the frequency and the revision of planned activities should provide the continued assurance of technical integrity. Reports of the effectiveness of the planned activities in assuring the required integrity and reliability shall be produced and reviewed by management, to ensure that the inspection activities are achieving the required performance.

Part of the review should include the effectiveness of the inspection procedures and routines in ensuring individual equipment is maintained fit for service. Also to be included is the review of the inspection routines to ensure that they are adequate for monitoring a failure type if a failure type occurs.

D.9 Reporting

The inspection method and calibrations should be recorded on the report, together with the inspector name and qualification level. Findings for each equipment item should be entered into the inspection management database.

Inspection reports should give conclusions as to the nature of the indication: relevant/irrelevant, crack/planar, pits with dimensions, local wall thinning dimensions, general wall thinning dimensions, crevice, etc. The corrosion and inspection engineer should evaluate the cause of such indications, the inspector shall report only what is found. The precise location of the indication shall be given in relation to a fixed datum, so that the indication can be readily found for re-evaluation. Sketches, photographs, screen pictures, etc., should be included in the report where these will aid in interpretation and recording. Where the conclusions are 'not acceptable' or 'further investigation', these should be registered in such a way that the follow-up actions are assigned, monitored and actively closed out.

D.10 Updates

On the basis that the inspection data has been evaluated and found valid, the wall thickness in the analysis should be updated to the measured thickness. The PoF should be re-calculated using the new thickness data but the original corrosion rate.

Where trending of the data is considered valid and is expected to continue into the future, the wall thickness should be corrected and a revised corrosion rate should be used to recalculate the PoF.

Guidance note:

The updates can result in either an increase or a decrease in the predicted PoF, depending on the inspection outcome.

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D.11 Inspection and monitoring data evaluation and analysis

D.11.1 General

Inspection results for process equipment usually comprise wall thickness measurements and reports of coating condition. Crack sizes are not normally monitored but repaired as soon as they are found. In all cases, inspection data shall be evaluated carefully before it is used to correct the estimates. The following are examples of issues to consider:

- The manner in which the data has been measured and reported
  - Are numerical values given for thickness or damage depth?
  - Is there an adequate reference to the original thickness?
  - Is the extent of damage to coatings given in relation to a numerical scale?
  - What inspection method has been used, and what is its effectiveness in measuring the expected degradation?
  - Has a sufficient area of the part been inspected to provide confidence that the result is applicable?
  - Can the results be related to identifiable locations within the part?
  - Are any past data points taken from precisely the same location, so that trending might be meaningful?
  - Has the inspection been carried out where the degradation would be expected?
- The applicability of the data to the situation under evaluation
  - Is the data taken precisely from the part being evaluated, or from the same corrosion group?
  - Where within the part has the data been taken?– Thickness measurements made on an elbow will not be correlated to the thickness of a straight pipe?.
- The applicability of the data to the expected degradation mechanisms
  - Is the measurement location relevant for the expected degradation mechanisms?
  - Does the data relate to internal or external degradation?
  - Does the data measure one or more degradation mechanisms, e.g. CO_2 corrosion and erosion simultaneously at an elbow?
- Variations and confidence in inspection results. It is common that there is a wide scatter in ultrasonic wall thickness measurements resulting from the inherent inaccuracy of the technique, slight changes in calibration from one inspection to the next, variations due to the operator, and variations due to non-repeatability in location.
- Trending possibilities/limitations. Two-point trending can show marked wall thickness loss rates or wall thickness increase rates. Increasing the number of points used in trending gives a better result, and it is strongly recommended that all relevant data points be plotted so that the best trend can be evaluated by eye as well as by a spreadsheet algorithm.
- Installation history. The evaluation must also include knowledge of relevant installation history. E.g., if many years of operation with effective corrosion inhibition have shown almost no wall loss, yet recently the inhibition equipment has failed, then the low corrosion rate cannot be expected to continue into the future unless inhibition is reinstated.
- Availability of baseline data. Where no baseline inspection data is available, it will be difficult to estimate a corrosion rate as the actual original thickness may be unknown and manufacturing tolerances are often large. Note that a comparison between adjacent areas of damaged and sound material can provide an adequate baseline in some cases.

A general checklist for evaluation and analysis of inspection data for use in inspection planning is given below. Together with these points, the general materials knowledge discussed elsewhere in this document should be considered.

D.11.2 Corrosion monitoring data

Corrosion monitoring data may be used in conjunction with the inspection data to give a picture of the actual situation. The type of data of interest may be:

— corrosion coupons
— direct corrosion rate measurement
— monitoring of key process parameters
— chemical analysis of the hydrocarbon fluid and the water.

Monitoring probes and coupons are generally not intended to provide quantitative degradation rates, but rather to monitor inhibitor performance or ensure that corrosion rates are within specified limits. However, data may be used for this purpose if it is given critical evaluation:

1) Have the probes or coupons been located in the correct position within the system, where the corrosion is expected to occur? The placement of a coupon on the top of a pipe where CO_2 corrosion is expected to occur in the water phase running along the bottom will give falsely optimistic results if the coupon does not lie in the water.
2) Has the data been collected and reported correctly? E.g. the calculation of pH from samples, the correlation of probe/coupon results with process conditions, use of the correct procedure to measure material loss from coupons or relate the signal change in a probe to corrosivity.

Where doubt exists in the use of these data, it should be discounted and new good quality data collected under the supervision of an experienced corrosion engineer. In the meantime, the corrosion rates estimated from the degradation models should be applied until the new, validated data is available.

Monitoring of key process parameters that control the rate or onset of degradation can be used to detect changes in the operating conditions that can affect the PoF.

Set points can be specified for relevant parameters and used for triggering inspection based on the PoF limit, rather than regular inspections. E.g., temperature is a key parameter for ESCC of stainless steels . Similarly, process instrumentation can be used to indicate when the basis for the RBI analysis is no longer valid. E.g., measurement of export gas CO_2 levels can be used as an indicator regarding the CO_2 content throughout the process, with a reanalysis to be carried out when there is a significant change.

D.11.3 Statistical evaluation of data

A number of statistical techniques may be used to evaluate the data, the following may be most relevant:

— regression analysis of wall thickness
— estimation of statistical quantities, e.g. mean, standard-deviation, skewness, kurtosis, for estimation of extreme values
— weibull analysis
— statistical plotting.

In all cases it is recommended to plot the results in proper graphs, as this will reveal any abnormalities in the data.

D.11.4 Grouping of data

The data should be grouped appropriately. The following categories are examples of groups that can be relevant when evaluating/analysing inspection data:

— material and service, or corrosion group/circuit
— component type: pipe, vessel, heat-exchanger, etc.

— age of component if replaced
— time period if there has been a change in process parameters: water content and chemistry, temperature, fluid composition.

D.11.5 Data quality checks

Check the quality of the data. Remove data from the data set based on one or several of the following:

— too high rate, i.e. failure within a few months
— data for measurement vs component replacement and age, e.g. check that replacement is taken into account
— measured thickness vs nominal wall thickness, e.g. data showing an increasing wall thickness may be removed from data set.

D.11.6 Application of data between corrosion groups/circuits

Corrosion rate data from one part of the plant may be used for other plants if the conditions are comparable.

Table D-1 Inspection and inspection effectiveness

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Uniform and local CO_2 corrosion Fluid systems (PL, PT and PW)	— Internal thinning of considerable areas or local internal wall thinning. Hot spots: — Bottom of dead legs and other low points where water can accumulate. — Piping and parts of vessels where water can condense. — Welds including HAZ in these areas should be focused on when selecting hot spots for inspection. — Turbulent areas expected to cause the most turbulent flow.	— UT — RT — CVI — Video inspection — Long range UT	100% of hot spots	30% of hot spots	10% of hot spots	— CO_2 corrosion is only a relevant mechanism for carbon steel. — Erosion-corrosion can be present if water content > 20% (full water wetting). — If water content > 5% and < 20%, be aware of dead legs. — Be aware of potential erosion problems in well stream (PT). — Be aware of potential MIC problems in semi process (PL, PT and PW).
Uniform and local CO_2 corrosion Gas systems (PV)	— Internal thinning of considerable areas or local internal wall thinning. Hot spots: — Bottom of dead legs and other low points where water can accumulate. — Piping and parts of vessels where water can condense. — Fluid areas in vessels. — When selecting hot spots for inspection, the focus should be on welds including HAZ in these areas.	— UT — RT — CVI — Video inspection — Long range UT	100% of hot spots	30% of hot spots	10% of hot spots	— CO_2 corrosion is only an actual mechanism for carbon steel. — Gas can be considered dry (no water wetting) if temperature is higher than 10°C above dew point, but dead legs must still be considered since they can have temperatures considerably below main process operating temperature.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Sulphide stress cracking (SSC)	— Internal surface breaking crack. Hot spots: — Case by case depending upon the design premises and welding QA-log.	— Inspection methods to be chosen case by case.				— Susceptibility type PoF-model. Not applicable for periodic inspection activities. — SSC is an expected mechanism for all steel grades. — All forms of cracking due to H_2S should be prevented by correct material selection.
Hydrogen induced cracking (HIC) Stepwise cracking (SWC) Stress oriented hydrogen induced cracking (SOHIC)	— Subsurface laminations or blisters parallel to surface, — Combination of such laminations/blisters and subsurface with cracks normal or parallel to surface. Hot spots: — Welds including HAZ (only for SOHIC). — History based on design premises and rolling QA-log.	— Inspection methods to be chosen case by case.				— The total equipment surface should be considered as suspect area. — HIC, SWC and SOHIC are relevant mechanisms for low-alloy rolled steels only. In general these mechanisms are not recognised as relevant for offshore process piping and vessels. For particular instances, where they are considered as relevant, it has to be evaluated whether they are applicable for periodic inspection activities under the current conditions. — Hydrogen-induced cracking is caused by nascent hydrogen atoms (H^o), usually produced in aqueous hydrogen sulphide (H_2S). Hydrogen atoms that enter the steel can cause embrittlement and failure.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Microbiologically influenced corrosion (MIC) in CS	— Internal local corrosion randomly distributed. — Local thinning. Hot spots: — Dead legs. — Areas where debris can accumulate.	— UT — RT — CVI — Video inspection — Magnetic flux leakage (MFL).	100% of equipment surfaces	100% of hot spots		— Susceptibility type PoF-model. — Probability of attack increases with reduced flow. — The corrosion rates due to MIC can be high. — MIC can occur in anaerobic hydrocarbon systems containing water and water dedicated systems when bacteria is present along with sulphates, fatty acids or other nutrition (see Table B-2). — Be aware that MIC can be an issue in connection with reproduction of injected seawater. — Be aware that MIC can be an issue for stabilized oil systems, drain systems and water injection systems. — Be aware the MIC can be an issue in the temperature range from 0°C to 80°C. — Be aware that the use of flow improver and other chemicals can contribute to MIC. — Be aware that biocide treatment might not be effective on bacteria protected under debris. Hence, debris cleaning activities have to be performed to ensure effective biocide treatment.
Microbiologically influenced corrosion (MIC) in stainless steels	— Internal local corrosion randomly distributed. — Local thinning. Hot spots: — Welds including HAZ in dead legs and areas where debris can accumulate.	—				— MIC is generally not expected in other materials than carbon steel in anaerobic systems. — MIC can occur in anaerobic hydrocarbon systems containing water and water dedicated systems when bacteria is present along with sulphates, fatty acids or other nutrition (see Table B-2).

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Erosion	— Internal wear of equipment surfaces due to sand in the process stream. — Thinning over an area corresponding to impingement. Hot spots: — High flow rate and local change of flow rate. — Local change of flow direction. — Different configurations of bends. — Downstream of choke-valves and other control valves. — Areas subject to impingement from jet-nozzles.	— UT — RT — CVI — Video inspection — UT long range	100% of hot spots	30% of hot spots	10% of hot spots	— Erosion issues are described in DNV-RP-F105. — Key process parameters: — Amount of sand, grain size and flow velocity. — Be aware that valve type can be of importance with regard to erosion. — Installation-specific studies and careful evaluation of local conditions can reduce the number of hot spots in a corrosion circuit down to only a few locations.
General corrosion of CS in utility water systems	— Internal thinning. Hot spots: — To be evaluated based on type of water system.	— UT — RT — CVI — Video inspection				— For water systems with higher predictability in location of most severe corrosion, the extent of hot spots can be reduced. — Key parameters are concentration of oxygen and Fe-ions in water.
Local corrosion of stainless steels in utility water systems	— Internal pitting. Hot spots: — Welds including HAZ.	— CVI — UT — RT				— Susceptibility type PoF-model. Not applicable for periodic inspection activities. — Key parameters are concentration of oxygen and Fe-ions in water.
	— Internal thinning in concealed faces forming a crevice. Hot spots: — Flanges, screwed connections and other components forming crevices.	— Disassembly and CVI — RT (screwed connections)				— Susceptibility type PoF-model. Not applicable for periodic inspection activities. — Key parameters are concentration of oxygen and Fe-ions in water.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
CUI, CS	— Local corrosion of external surfaces under insulation. — Thinning in patches. Hot spots: — Penetrations through deck or wall. — Unpainted surfaces and surfaces with painting in poor condition. — Areas subject to water ingress due to poor installation or condition of vapour barrier or design of equipment. — Low points and water entry points. — Corners where water can collect. — Areas where water condenses.	— Deinsulation and CVI — RT — Real time profile RT — Long range UT	100% of equipment surfaces	100% of hot spots		— Inspection methods for screening for hot spots: CVI, thermography, real time profile RT or humidity measurements in insulation. — Note that field welds can be subjected to CUI due to substandard surface treatment or insulation work. — Note that CUI has been seen independent of insulation material used. — Note that presence and functionality of drainage facilities can be of importance to CUI. — Note that severe CUI may occur in the sections where pipe crosses through a wall or a deck.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
CUI, stainless steels	— Local corrosion and pitting of external surfaces under insulation. — Local pitting. Hot spots: — Welds including HAZ and areas subject to heavy cold work that are unpainted or with painting in poor condition, located in the following locations: — Areas subject to water ingress due to poor installation or condition of vapour barrier or design of equipment. — Low points and water entry points. — Corners where water can collect. — Areas where water condenses.	— Deinsulation and CVI — Deinsulation and PT				— Susceptibility type PoF-model. Inspection for conditions causing corrosion followed by actions to remove cause might give reduction in PoF. — Inspection methods for screening for hot spots: CVI, thermography or humidity measurements in insulation. — Note that field welds can be subjected to CUI due to substandard surface treatment or insulation work. — Note that CUI has been seen independent of insulation material used. — Note that presence and functionality of drainage facilities can be of importance to CUI.
ESCC under insulation	— External surface breaking crack. Hot spots: — Welds incl. HAZ and areas subject to heavy cold work that are unpainted or with painting in poor condition, located in the following locations: — Areas subject to water ingress due to poor installation or condition of vapour barrier or design of equipment. — Low points, corners and other places where intruding water can collect. — Wet surfaces with chloride deposits.	— Deinsulation and ET — Deinsulation and PT — Deinsulation and creep wave UT				— Susceptibility type PoF-model. Inspection for conditions causing corrosion followed by actions to remove cause might give reduction in PoF. — Inspection methods for screening for hot spots: CVI, thermography, humidity measurements in insulation. — Key parameters are material surface temperatures / operating temperatures. — Note that field welds can be subjected to ESCC due to substandard surface treatment or insulation work. — Note that ESCC has been seen independent of insulation material used. — Note that presence and functionality of drainage facilities can be of importance to ESCC.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
External corrosion of uninsulated carbon steel	— Uniform and local corrosion of external surfaces. — Thinning in patches. Hot spots: — Unpainted surfaces or surfaces with painting in poor condition with the following conditions: — Corners where water can collect. — Areas where water condenses. — Under deposits of dirt, etc. — Drips onto hot piping.	— CVI	100% of equipment surfaces			— Inspection methods for screening for hot spots: GVI. — Note that field welds and repair welds can be subjected to external corrosion due to substandard surface treatment. — Note that surface treatment maintenance is vital for control of external corrosion.
External corrosion of uninsulated stainless steels or titanium External crevice corrosion	— Local corrosion and pitting of external surfaces. — Local pitting. Hot spots: — Discolouration. Welds including HAZ, areas subject to heavy cold work or areas contaminated with carbon steel material from grinding, etc., without painting or with painting in poor condition and the following conditions: — Corners where water can collect. — Areas where water condenses. — Under deposits of dirt, etc. — Drips onto hot piping.	— CVI — PT	100% of hot spots			— Inspection methods for screening for hot spots: GVI. — Note that field welds and repair welds can be subjected to external corrosion due to substandard surface treatment. — Note that surface treatment maintenance is vital for control of external corrosion.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
	— Local thinning in concealed faces forming a crevice. Hot spots: — Flanges and other details forming crevices. — Under clamps. — Under adhesive tape or other markings.	— Disassembly and CVI — RT (Screwed connections) — CVI combined with creep wave or long range UT	100% of hot spots			— CVI to be followed up by disassembly or NDT if visual indications of corrosion are detected. — Note that design solutions and passivation control can be of importance to local corrosion.
Oxygen contamination corrosion	— Internal thinning of considerable areas — Local internal wall thinning.	— CVI — UT — RT				— No PoF-model available for this degradation mechanism. — Note that the combined effect of oxygen and CO_2 on the corrosion rate will tend to increase the overall rate. — Be aware of the possibility of oxygen contamination due to use of platform nitrogen as purge gas.
Elemental sulphur corrosion	— Local internal wall thinning.	— CVI — UT — RT				— No PoF-model available for this degradation mechanism. — Note the possibility of elemental sulphur formation due to a reaction with oxygen in a wet gas environment. — Note that if chloride is present, the corrosion rate can be accelerated.
Local corrosion in connection with injection or mixing points	— Local internal wall thinning. Hot spots: — Injection and mixing points including downstream piping and bends.	— CVI — UT — RT	100% of hot spots			— No PoF-model available for this degradation mechanism. — Be aware that the corrosion rate can be accelerated due to turbulence.
Galvanic corrosion	— Local corrosion due to contact between different materials (See the galvanic series). — Internal and external. Hot spots: — Areas on the least noble metal close to material breaks.	— CVI — UT — RT	100% of hot spots			— No PoF-model available for this degradation mechanism. — Consider the material design, control, and focus the follow-up on isolation spool pieces. — Note the potential of corrosion of plugs with reference to plug type and plug material.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Weld corrosion	— Local corrosion due to use of deposited metal not according to specification. — Internal and external.	— CVI — UT — RT	100% of hot spots			— No PoF-model available for this degradation mechanism. — Control and follow-up should be focused on welding processes and deviation log.
Fretting corrosion	— Local corrosion due to fretting. — Valid for both piping and vessels. — Internal and external. Hot spots: — To be evaluated based on Design, Fabrication, Installation and Operation (DFI&O) documentation.	— CVI — UT — RT	100% of hot spots			— No PoF-model is available for this degradation mechanism. — Control and follow-up should be focused on equipment installation and operation.
Corrosion under plate cladding	— Local corrosion due to defects in plate cladding of equipment. Hot spots: — To be evaluated based on DFI&O documentation.	— UT — CVI — ET		100% of hot spots		— No PoF-model is available for this degradation mechanism. — Focus on the control and follow-up on cladding installations.
Weld overlay corrosion	— Local corrosion due to defects in weld overlay of plates, nozzles and flanges. Hot spots: — To be evaluated based on DFI&O documentation.	— UT — CVI — ET — PT		100% of hot spots		— No PoF-model is available for this degradation mechanism. — Control and follow-up to be focused on weld overlay installations. — Severe corrosion has been seen due to weaknesses of weld overlay.
Flange corrosion	— Local corrosion due to gasket deformation or use of wrong gasket. Hot spots: — To be evaluated based on DFI&O documentation.	— CVT	100% of hot spots			— No PoF-model is available for this degradation mechanism. — Control and follow-up on preservation of flanged connections. Focus on the correct use of gaskets and bolts. — There is a possibility of corrosion on the outer part of the seal assembly.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Bolt corrosion	— Local corrosion due to defect in bolt material, galvanizing or to high utilization of threads. Hot spots: — To be evaluated based on DFI&O documentation.	— CVI — PT — ET	100% of hot spots			— No PoF-model available for this degradation mechanism. — Severe corrosion of galvanized bolts can occur resulting in degradation of galvanization.
Fatigue	— Internal or external cracking of cyclically- stressed components. — Surface breaking crack from external surface or from pre-existing defect. Hot spots: — Welds in systems with cyclic loads in connection with: — Clamped supports, branching points nozzle attachments and other fixing points. — Marked changes in dimensions. — 'Sockolets' for heavy equipment mounted to piping through smaller dimension piping. — Smaller diameter branching connections. — Internal equipment vessels.	— Measurement of oscillating stresses				— Inspection for cracking will not give significant reduction in PoF for components with unacceptable oscillating stresses, but inspection for conditions causing vibrations followed by actions to remove cause might give reduction in PoF. — Inspection methods for screening for hot spots: GVI. — Focus on the design, installation, supporting and weld grinding. — There is a possibility of fatigue internally in static equipment due to liquid slugs and thermal cyclic processes.
Brittle fracture	— Severe defect due to uncontrolled material embrittlement. Hot spots: — Hot spots to be evaluated based on DFI&O documentation.	—				— No PoF-model is available for this degradation mechanism. — Focus on the conditions that can lead to brittle fracture.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Internal damage to shell and tube heat exchangers	— Internal defects due to design and fabrication, installation or in-service stress factors.	— CVI	100% of hot spots			— No PoF-models is available for these degradation mechanisms. — There is a possibility of corrosion between tube and tube sheet. — There is a possibility of cracking between tube and tube sheet. — There is a possibility of deformation (cracking) of tubes. — There is a possibility of corrosion if cracking or damage to internal lining in channel / tube sheet. — There is a possibility of damage (fatigue / tear out) to the deviation sheet of the channel. — There is a possibility of damage to tubes and tie rods due to lack of impingement protection. — There is a possibility of burst of tubes due to hydrate formation.
Internal corrosion of carbon steel vessels	— Uniform and local corrosion of internal surfaces. — Thinning in patches. Hot spots: — Unpainted surfaces or surfaces with painting in poor condition with the following conditions: — Corners where water can collect. — Areas where water condenses. — Under deposits of dirt, etc.	— CVI	100% of equipment surfaces			— Inspection methods for screening for hot spots: GVI. — Field welds and repair welds can be subjected to corrosion due to substandard surface treatment. — Surface treatment maintenance is vital for control of corrosion. — If anodes are installed then the consumption of anodes can predict the corrosivity.

Damage mechanism	*Damage description*	*Inspection method*	*Highly effective*	*Effective*	*Fairly effective*	*Comments*
Mechanical damage	— Internal or external local defects due to mechanical impact under fabrication, installation or in service.	— CVI	100% of hot spots			— No PoF-model is available for this degradation mechanism. — Follow-up to be focussed on in-service mechanical damage. — There is a possibility of mechanical damage internally in static equipment due to liquid slugs and thermal cyclic processes. — Be aware of the potential for severe defect due to uncontrolled hydrate formation.

CHANGES – HISTORIC

July 2017 edition

General

This document supersedes the October 2010 edition of DNV-RP-G101.

The purpose of the revision of this service document is to comply with the new DNV GL document reference code system and profile requirements following the merger between DNV and GL in 2013. Changes mainly consist of updated company name and references to other documents within the DNV GL portfolio.

Some references in this service document may refer to documents in the DNV GL portfolio not yet published (planned published within 2017). In such cases please see the relevant legacy DNV or GL document.

References to external documents (non-DNV GL) have not been updated.

About DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.

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