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REPORT

Ageing and life extension for offshore facilities in general and for specific systems

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ABSTRACT

Life extension (LE) is an important issue for a number of facilities on the Norwegian Continental Shelf. Many fields have recoverable oil/gas reserves extending the facility's original design life, but certain analyses are required to ensure that safety will not be compromised in case of LE.

The report provides an overview of issues related to ageing and management of LE for offshore facilities. The principal aspects of an LE assessment process is outlined, including physical degradation, obsolescence and human/organisational consequences. This work comprises data collection, identification of relevant requirements and regulations, and analyses. A screening process is also needed to identify the systems, structure and components (SSC) where a more detailed analysis is required. Further, the report presents an overall approach for risk assessment related to LE and provides relevant measures for the LE period. The LE management plan is discussed, too.

Five systems are studied in more detail to illustrate typical ageing phenomena and possible challenges:
1. Material handling and lifting equipment.
2. Wells.
3. Pipelines, risers and subsea systems.
4. Topside processing equipment.
5. Safety systems.

2-5 are investigated mainly with respect to physical degradation, and 1 (and slightly 2) are investigated mainly with respect to obsolescence (outdated operations/technology) and organisational challenges.

Note that structures are not dealt with specifically in the report, as much has been written on ageing and structures.

KEYWORDS	ENGLISH	NORWEGIAN
GROUP 1	Safety	Sikkerhet
GROUP 2	Offshore	Offshore
SELECTED BY AUTHOR	Life Extension	Levetidsforlengelse
	Ageing	Aldring

Preface

The report has been prepared for the PSA by SINTEF Department of Safety Research, in co-operation with various NTNU and SINTEF departments, in particular NTNU Engineering Design and Materials.

The following colleagues have made a notable contribution:

- Stig Berge (NTNU MARINTEK)
- Inge Carlsen (SINTEF Petroleum and Energy)
- Martin Fossen (SINTEF Petroleum and Energy)
- Stein Hauge (SINTEF Technology and Society, Safety Research)
- Per J. Haagensen (NTNU Structural Engineering)
- Ole Meland (SINEF Technology and Society, Safety Research)
- Erlend Olsø (SINTEF Materials and Chemistry)
- Tor Onshus (NTNU ICT, Technical Cybernetics)
- Peter Sandvik (SINTEF MARINTEK)
- Anders Valland (SINTEF MARINTEK)

We have had several meetings with the PSA, and would like to thank Gerhard Ersdal, Oddvar Øvestad, Ola Heia, Reidar Hamre and Hans Spilde for useful discussions and valuable input to this report.

A draft version of the report was reviewed by

- John Sharp (Cranfield University)
- David Galbraith (Ocean Structures)
- Mamadouh Salama (ConnocoPhillips)
- Jan Andreassen (Eon Ruhrgass)
- Svein Bjørberg (Multiconsult/NTNU)

And we would like to thank them for their consultative capacity.

Trondheim 2010-03-19
Per Hokstad

Summary and conclusions

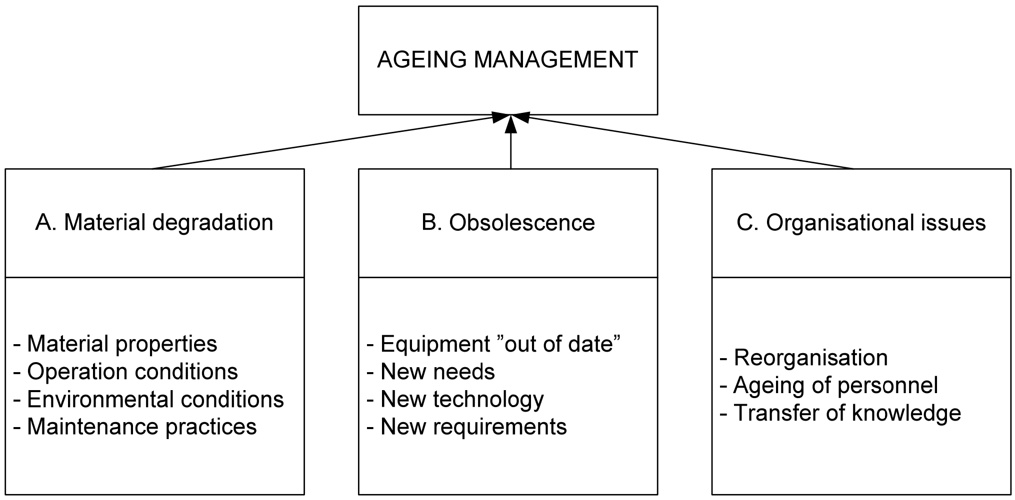
A large number of facilities and parts of the infrastructure on the Norwegian Continental Shelf (NCS) are approaching or have exceeded their original design life. Many fields, however, have remaining recoverable oil and gas reserves which may be profitable if the field's life time is extended. From a safety point of view, the condition of systems, structure and components (SSC) may not be acceptable for extended operation.

The main objectives of this report are:

- To give an overview of and discuss various aspects of ageing related to offshore facilities, the risk they represent to the integrity of a facility and how to deal with them in an LE process, i.e. the basis for deciding on LE. How to document the safety of an ageing facility, in particular, and how to uphold the safety level by means of a maintenance programme balancing the ageing mechanisms.
- To identify possible knowledge gaps and suggest recommendations for those facing LE of offshore facilities.

The report considers three aspects of ageing, illustrated in the figure below:

- Material degradation.
- Obsolescence, i.e. operations and technology being "out of date".
- Organisational issues.



Adopted from: "Ageing of Components and Systems". Edited by Lars Pettersson and Kaisa Simola. An ESReDA Working Group Report.

LE process
The report describes an LE process consisting of six main steps, see figure below. These are:

1. *Data & information* collection required to identify and analyse relevant risk factors and required risk reducing measures. This also includes establishing (risk) acceptance criteria to carry out LE.

2. *Criticality (primary) screening* of SSC, to identify critical units and barriers with respect to failure consequence and probability. Other aspects such as redundancy, common cause failures, detectability of failure and system availability are also considered.

3. *Analysis of failures and challenges*
With respect to material degradation it is necessary to perform a secondary screening considering the

- *Availability for inspection/monitoring* of the SSC, to obtain knowledge about its current state.
- *Accessibility for maintenance and/or modification* of the SSC

With respect to obsolescence and organisational issues it is necessary to identify challenges and gaps in relation to current requirements.

4. Identification and evaluation of potential *risk reducing measures.*

5. An assessment of the *overall risk picture* based on all aspects of ageing, given the risk reducing measures.

6. *If* the overall risk picture is acceptable, an *LE management plan* should be implemented that ensures integrity throughout the LE period and

- Makes sure that the facility's technical, operational and organisational integrity level is maintained during the LE.
- Is adjusted to today's and (expected) future type of operation, organisation and requirements.

If the overall risk picture is *not* acceptable, additional risk reducing measures must be identified and a new maintenance and modification plan prepared.

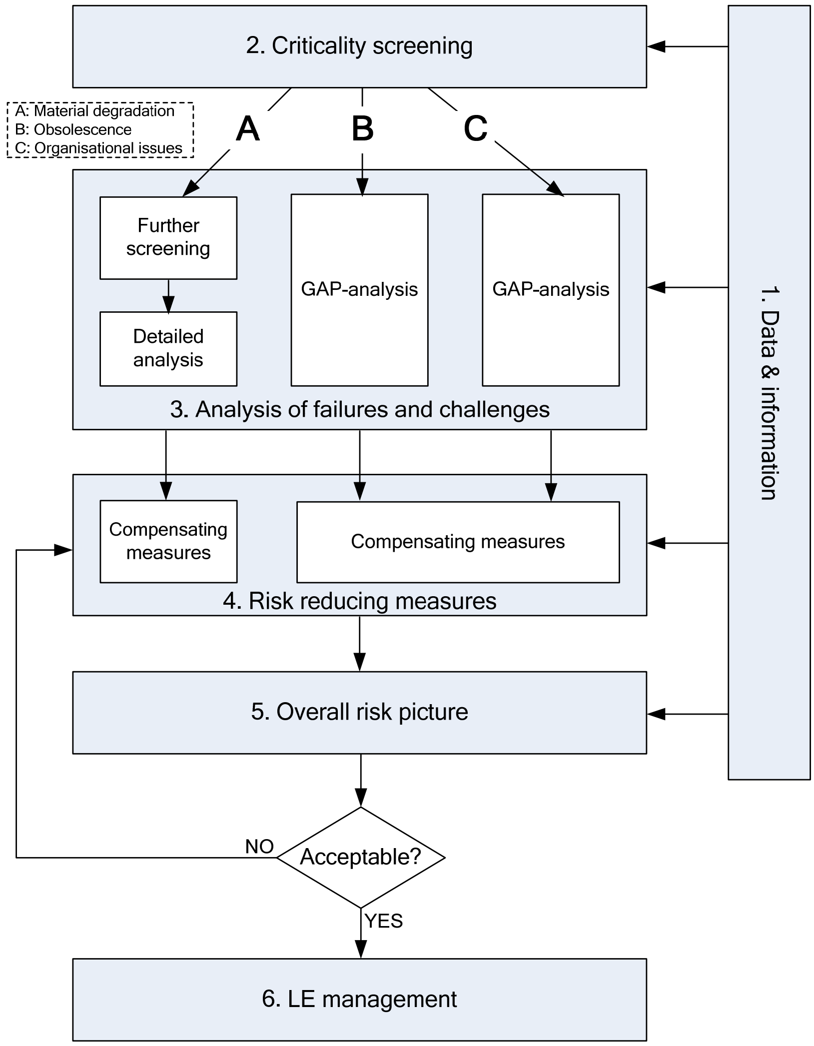
The report presents some "case studies" to illustrate aspects of the LE process. Relevant questions with respect to obsolescence and organisational issues are exemplified by:

- Lifting equipment and material handling.

The following systems are investigated and exemplified mainly with respect to material degradation:

- Wells.
- Subsea production and transportation systems.
    - Pipelines.
    - Flexible risers.
    - Subsea production systems.
- Topside process equipment.
- Safety systems.

Note that structures are not dealt with specifically in the report, as much has been written on ageing and structures. However, the general part (chapters 1-3) in the report is also applicable to structures and other systems.



Knowledge gaps related to ageing
In this report the following knowledge gaps have been identified:

- Understanding and assessing degradation mechanisms and modelling of degradation mechanisms for various materials and equipment.
- Developing and applying reliable methods for subsea inspection and monitoring.
- Understanding and increasing awareness of common cause failures of equipment due to ageing.
- Assessing the effects of and utilising methods for monitoring of facility loads.
- Understanding ageing of electronic equipment and cabling.
- Optimising test intervals for safety systems with respect to material degradation.
- Understanding the results of testing, inspection and monitoring of process equipment with respect to degradation mechanisms.
- Understanding the consequences of combining old and new equipment.
- Assessing the effects of subsidence on relevant SSC, such as structure, helideck and free fall lifeboats.

Important issues to consider for operators in a life extension process
The operator should ensure the technical, operational and organisational integrity of the facility during an LE period; in particular, (analogue to the abovementioned LE process):

- Ensuring that safety is maintained throughout the entire LE period.
- Preparing a screening process to identify which SSC are critical with respect to ageing.
- Establishing a reliable estimation of material degradation of the critical SSC caused by degradation mechanisms relevant to the given SSC.
- Specifying an analysis (e.g. by providing a check list) for identifying obsolescence and organisational risk factors, e.g. deviations from requirements, lack of spare parts and lack of competence.
- Establishing a process for identifying cost-effective measures to close identified gaps.
- Including uncertainties and future changes of the system, also considering possible impacts from the surroundings.
- Ensuring sufficient competence to carry out LE assessments and to follow them up during the LE period.

Further research and development
In the report, the following recommendations for research and development have been found:

1. Initiating an interdisciplinary project on analyses of degradation mechanisms of critical systems, comprising:
    a. Modelling of the main degradation mechanisms, also considering the combined effect of various degradation mechanisms, common cause failures and effect of operational conditions.
    b. Development of systems for data collection and use of field experience with degradation failures.

2. Developing a general guideline for design of the LE processes encompassing the entire facility, e.g. by means of a case study.

3. Improving maintenance management systems for ageing and life extension so that all three ageing aspects are being “processed” in parallel, in order to evaluate and improve the operator’s maintenance systems prior to and during life extension. Such management would mean improved awareness and overall knowledge of the SSC on the facility, e.g. combinations of old and new equipment, availability of spare parts, common cause failures, new types of operation and new technology.

TABLE OF *CONTENTS*

1 Introduction

1.1 Background

A large number of facilities and parts of the infrastructure on the Norwegian Continental Shelf (NCS) are approaching or have exceeded their original design life. Many fields, however, have remaining recoverable oil and gas reserves which may be profitable if the field's life time is extended. From a safety point of view, the condition of systems, structures and components (SSC) may not be acceptable for extended operation.

Thus, formal assessments are needed to demonstrate that there is sufficient technical, operational and organisarional integrity to continue safe operation throughout a life extension (LE), something which requires detailed information on history, the current state and prediction on the future state of the facility.

1.2 Objectives

The main objectives of this report are:

- To give an overview of and discuss various aspects of ageing related to offshore facilities, the risk they represent to the integrity of a facility and how to deal with them in an LE process, i.e. the basis for deciding on LE. How to document the safety of an ageing facility, in particular, and how to uphold the safety level by means of a maintenance programme balancing the ageing mechanisms.
- To identify possible knowledge gaps and suggest recommendations for those facing LE of offshore facilities.

1.3 Structure of report

Chapters 2-4 deals with the *general part;* chapters 5-9 the specific part (analysing specific systems on a facility).

Chapter 2 begins with a short introduction to the three aspects of ageing and ageing management, i.e. material degradation, obsolescence and organisational issues. Further, we describe the main tasks of the process prior to submitting an LE application, including system breakdown, screening, data collection, identification of challenges, risk analyses, risk reducing measures and an overall LE management plan. Chapter 2 and the following two chapters also refer to some of the material found in the literature review, (also see Appendices B and C). A more comprehensive literature review performed by SINTEF is given in the memo [78].

Chapter 3 presents ageing issues relating to material degradation, i.e. degradation mechanisms, failure modes, process parameters, operational conditions and maintenance. The chapter also presents some models for material degradation and gives an example of a general approach to LE assessment with respect to material degradation only. The approach is based on existing procedures for life extension of specific systems and on risk assessment for oil and gas production systems. The example is presented in Appendices F and G.

Chapter 4 presents ageing issues relating to obsolescence and organisational issues (including human issues). New requirements, new types of operation, new technology, changes in organisation and knowledge and competence are covered. For each topic we provide a list of questions that should be verified in a life extension assessment. The chapter also discusses gap analyses for identifying and closing gaps in relation to current requirements.

Chapter 5 analyses obsolescence and organisational issues from chapter 4 with respect to

- Material handling and cranes.

In *Chapters 6-9* four specific systems are analysed with respect to material degradation:

- Wells (*Chapter 6*)
- Subsea production and transport (*Chapter 7*)
  - Pipelines (Chapter 7.2)
  - Flexible risers (Chapter 7.3)
  - Subsea production systems (Chapter 7.4)
- Process equipment (*Chapter 8*)
- Safety systems (*Chapter 9*).

Note that structures are not investigated specifically in this report. A separate report, [56], has been written on main load bearing *structures.* However, the general part (chapters 2-4) applies for all SSC, structures included.

Relevant literature is also reviewed in these chapters.

Finally, a summary is presented in *Chapter 10*, summing up main challenges, uncertainties and areas with lack of knowledge.

Definitions and abbreviations are given in *Appendix A.*

Appendices B and C give a summary of relevant findings of the literature review and a list of reviewed documents, respectively.

Appendix D describes degradations mechanisms related to flexible risers, and *Appendix E* gives an overview of failure modes for safety system equipment.

Appendices F and G give an example of an LE assessment approach with respect to material degradation and give examples of wells and topside process equipment.

The structure of the report is illustrated in Figure 1.

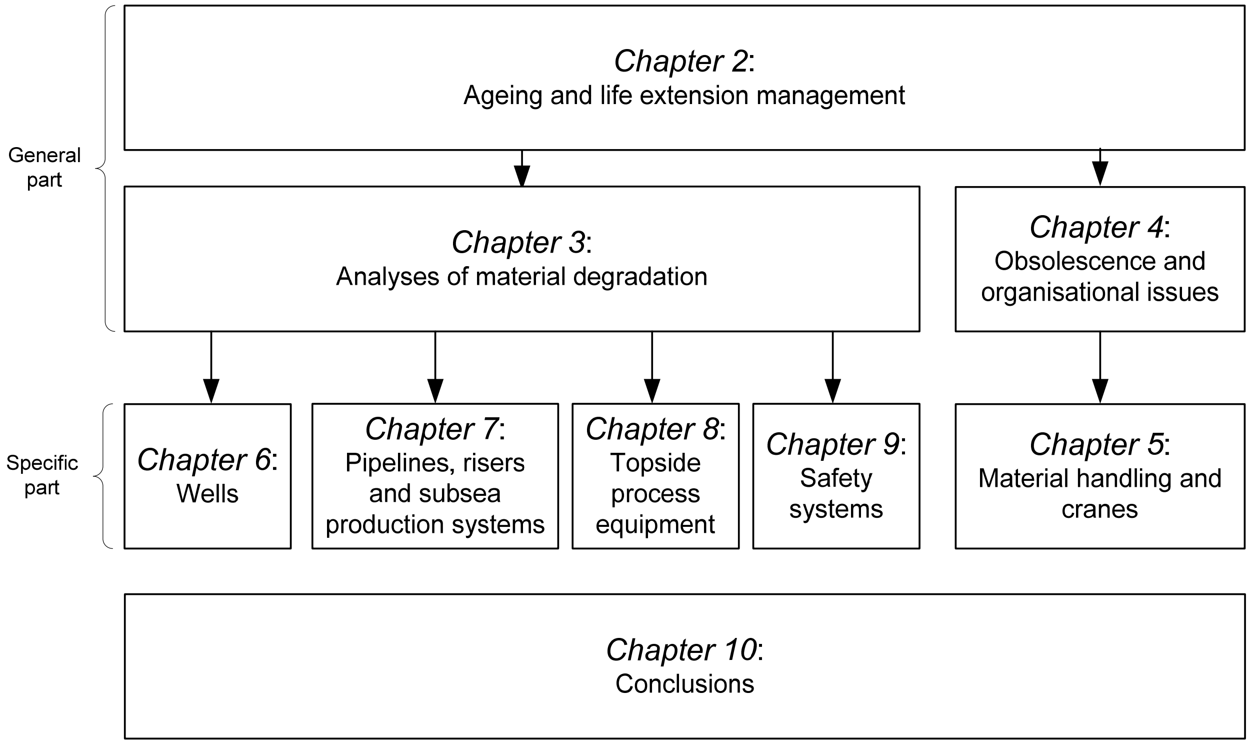


Figure 1: Structure of report

1.4 Limitations and assumptions

The research carried out in this report is based on a set of documents (reports/papers), agreed upon with the PSA (Petroleum Safety Authority Norway); supplemented with other literature, information obtained from experts at SINTEF/NTNU and feedback from international reviewers. There has been no contact with the offshore industry in order to utilise their experience and knowledge.

The report focuses mainly on ageing challenges that relate to process risk and the risk for major hazards. Thus, occupational risk and working environment are addressed to a limited extent, only.

The report also focuses on the operational phase. The decommissioning phase is not part of the scope, but many of the issues related to operation are also applicable to decommissioning.

Note that *structures* are not dealt with specifically in the report, as much has been written on ageing and structures. However, the general part (chapters 1-3) in the report is also applicable to structures and other systems.

2 Ageing and life extension management

This chapter gives an overview of tasks relevant to the LE process; i.e. the process prior to submitting an LE application. Firstly, we suggest a categorisation of the various aspects of ageing management issues. Then we describe the main tasks of the LE process, including screening, data collection, identification of challenges, analyses, risk reducing measures and an overall LE management plan. Finally, we list some uncertainties related to life extension and the LE process.

2.1 Categorisation of ageing management issues

Material degradation (physical impairment) is an important aspect of ageing, but also obsolescence, organisation and operational needs are important issues. The following categorisation is suggested for the different aspects of ageing management, (adapted from [15]):

A. Material degradation (physical ageing), *due to* e.g.
    a. Material properties
    b. Operational condition (and changes in operational conditions)
    c. Environmental condition (and changes in environmental conditions)
    d. Maintenance practices

B. Obsolescence, e.g.
    a. Equipment becomes “out of date”, leading to e.g. non-available spare parts, services, etc.
    b. New needs and new types of operations requiring new technology or giving other operational/environmental conditions
    c. Design changes due to new technologies
    d. New requirements

C. Organisational issues, e.g.
    a. Reorganisation
    b. Ageing of facility personnel and transfer of knowledge
    c. New operations that require changes in the organisation
    d. Changes in required competence
    e. Increase in work load (e.g. due to increased maintenance)

This categorisation is illustrated in Figure 2. Most of the literature focuses on the physical impairment / material degradation (A), but the aspects B and C listed above also represent changes that are essential in ageing management.

Obsolescence (B) comprises equipment that is outdated / replaced by something newer, possibly causing challenges related to availability of spare parts. We also include the possibility of new operational requirements being effectuated, or the operation itself becoming more demanding; thus resulting in new requirements to existing equipment. In addition to outdated technology, obsolescence includes new needs, where one need can be a consequence of another. For example, to extract oil from reservoirs located further away from the facility and existing wells, new tie-ins and new types of wells are needed. This, in turn, results in a need for new technology. Another example is the need for new technology as a consequence of new regulatory requirements.

Aspect C, organisational and human resources, deals with the importance of having clear responsibilities, maintaining expertise, (e.g. transferring knowledge from retiring personnel) and revising documents.

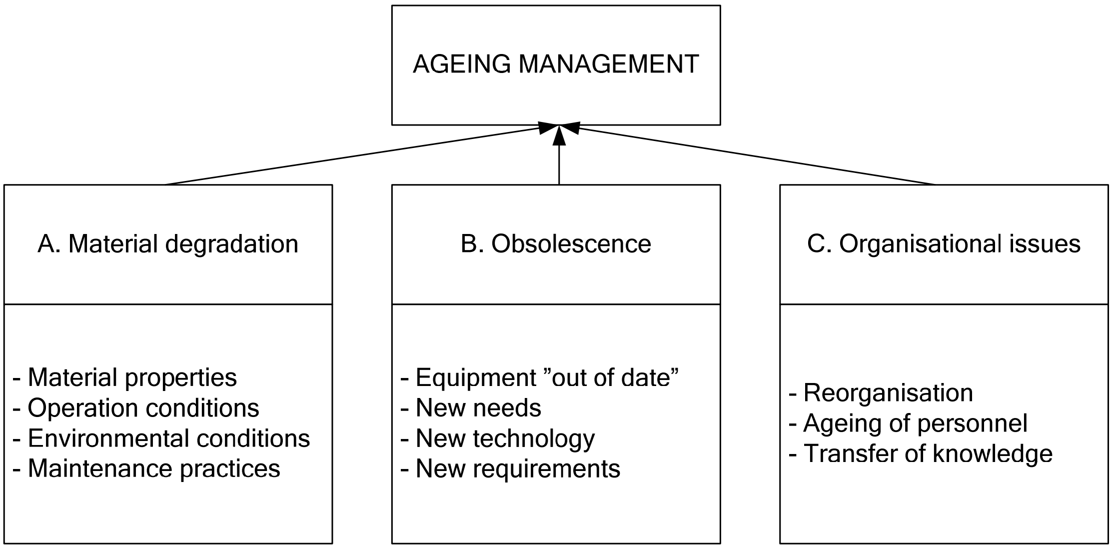


Figure 2: Aspects of ageing management, based on [15]

When LE is considered, the main challenges of each of these aspects of ageing must be identified, plus measures to cope with these challenges. Note that challenges are identified at different "levels". While material degradation can be evaluated at a component, equipment and system level, the organisational issues are mostly evaluated at system or even facility level. Obsolescence will most often be addressed at system level.

Part of the ageing management and LE assessment is to carry out analyses to identify the possible deviations of equipment, organisations and human resources, in terms of the ability to satisfy all future demands and requirements. In the following sections we will present a framework for the LE process; partly based on the literature presented in Appendix B.

2.2 Main tasks of a Life Extension process

The main question is how to perform the process for deciding on LE, without compromising safety. Firstly, all (possible) challenges related to ageing and future operation must be identified, incorporating the whole facility and safety related systems and equipment on the facility. Secondly, the challenges should be analysed with respect to risk throughout the LE period. Finally, a maintenance and modification plan to reduce the risk contribution from all equipment and systems must be prepared and implemented in order to maintain (or, if required, improve) the safety integrity and to comply with the current requirements.

The analyses should only be performed for functions and systems (or barriers) that are critical to safety, and it is suggested that the LE process should include the following six activities, (which are further discussed in subsequent sections):

1. *Data & information* collection required to identify and analyse relevant risk factors and required risk reducing measures. This also includes establishing (risk) acceptance criteria to carry out LE.

2. *Criticality (primary) screening* of SSC, to identify critical units and barriers with respect to failure consequence and probability. Other aspects such as redundancy, common cause failures, detectability of failure and system availability are also considered.

3. *Analysis of failures and challenges*
With respect to material degradation it is necessary to perform a secondary screening considering the

- *Availability for inspection/monitoring* of the SSC, to obtain knowledge about its current state.
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4. Identification and evaluation of potential *risk reducing measures.*

5. An assessment of the *overall risk picture* based on all aspects of ageing, given the risk reducing measures.

6. *If* the overall risk picture is acceptable, an *LE management plan* should be implemented that ensures integrity throughout the LE period and

- Makes sure that the facility's technical, operational and organisational integrity level is maintained during the LE.
- Is adjusted to today's and (expected) future type of operation, organisation and requirements.

If the overall risk picture is *not* acceptable, additional risk reducing measures must be identified and a new maintenance and modification plan prepared.

The process is illustrated in Figure 3. Note that activity 3 will be slightly different when analysing aspect A (material degradation) and aspects B/C. Also observe that the outcome of the overall risk picture (activity 5) may be that additional risk reducing measures must be implemented, (i.e. returning to activity 4).

The process is in line with the principles of the ageing management plan described in the IAEA Safety Standard, [28] which treats both physical ageing and obsolescence of SSC and gives a rather detailed description of the principles for ageing management of nuclear power plants; see Appendix B of this report. Also, the IAEA approach includes a process related to screening of the SSC. However, there are some differences between offshore and nuclear industry with respect to ageing. One of the most considerable differences is within the operational conditions, which for the nuclear industry stays more or less constant. Operational conditions in the offshore industry may change due to new types of operations, new types of liquid/gas, etc. Thus, varying operational conditions will affect all three types of ageing, e.g. new operational conditions may for some equipment result in other degradation mechanisms and new operational conditions may be equivalent to new types of operations requiring different types of competence.

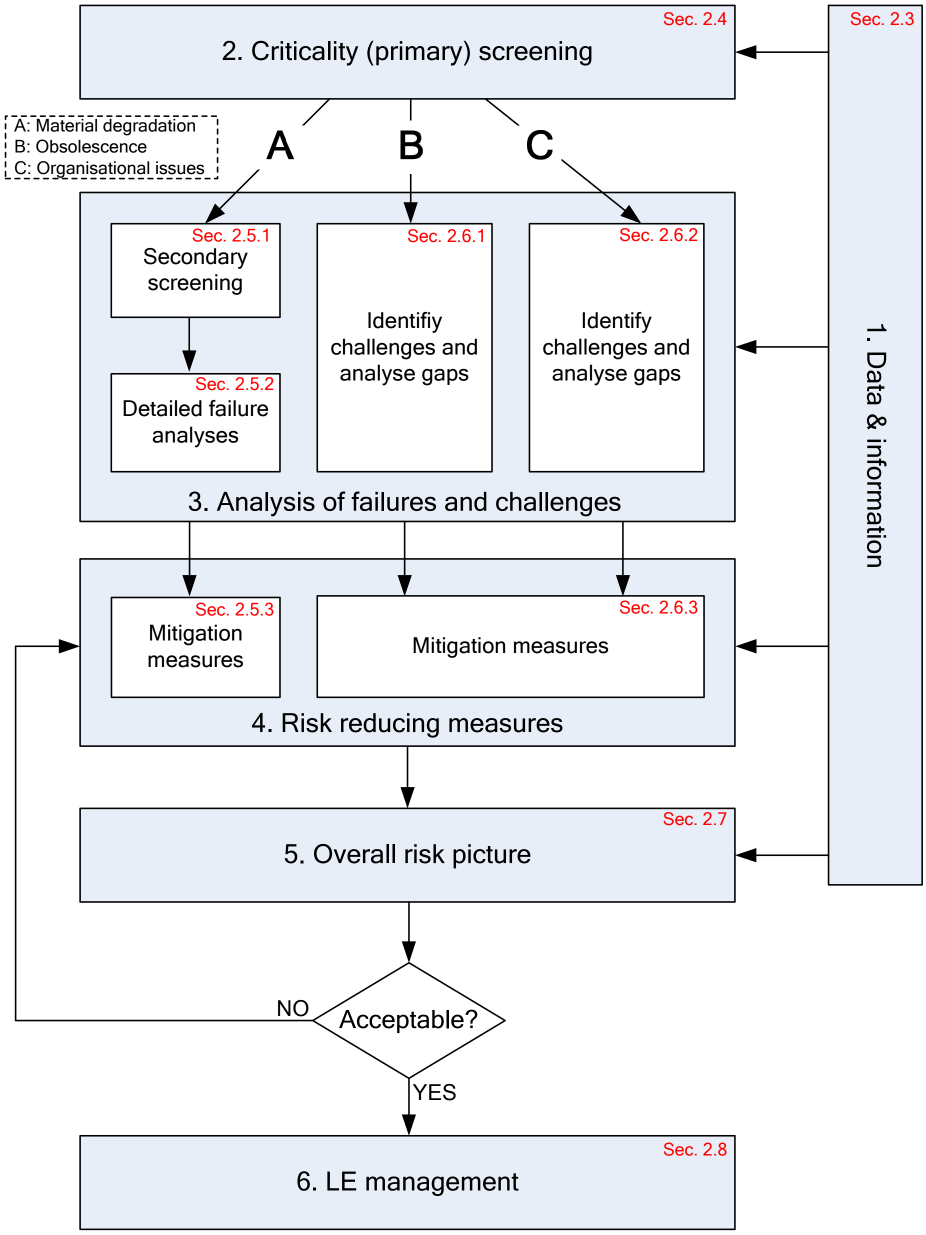


Figure 3: Framework for the LE process

Section 10 of the OLF Guideline, [60], states that analyses and evaluations in cases of LE must demonstrate that the following can be achieved:

- Compliance with the regulations throughout the period
- Acceptable technical integrity throughout the period
- Acceptable risk levels throughout the period
- Acceptable management of ageing processes.

These are four basic conditions for LE, which must be addressed in the LE management plan. In addition, the availability of required competence is an essential issue. The following sections will discuss activities 1-6 in more detail. Material degradation (A) is further discussed in Chapter 3, and obsolescence/organisational issues (B/C) in Chapter 4.

2.3 Data and information collection

Activity 1 in the LE process is data and information collection for the facility, including data about

1. Design and installation phase
2. Operational phase
3. LE phase
4. Requirements and regulations
5. Relevant research and development results (e.g. new technology)
6. Information from other facilities / other industries on ageing
7. Investigation results.

Details about 1-4 are given below:

1. Information on *design and installation phase*, e.g.
   a. Documentation of original design, fabrication, installation
   b. Drawings and computer models; check that these are in accordance with as-is condition, ensuring that changes since as-built condition are included
   c. Quantitative Risk Analyses (QRAs)
   d. Operation and process information at design phase
   e. Investigation reports of installation loads (if relevant)
   f. Investigation reports of installation accidents (if relevant).

2. Information on history (*operation phase*), e.g. from
   a. Maintenance programmes
   b. Performed modifications
   c. Performed repairs
   d. Process-, operation- and environmental parameters
   e. Condition monitoring. (An important aspects is whether degradation has developed slowly over time or has increased rapidly in the recent past)
   f. Inspection and testing; (as “no crack” detections during inspections)
   g. Investigation reports of accidents and incidents and influence on structures strength (if relevant)
   h. Information from similar operations (other facilities with similar equipment)
   i. New and/or additional standards and recommended practice
   j. Overview of exemptions that have been granted.

In addition, the information from design and installation phase should be updated in the operational phase.

3. Information on *future* conditions (during period of LE)
   a. Future process- operation- and environmental parameters, incl. activity level
   b. Future capabilities to monitor, access, operate and maintain the SSC
   c. Other relevant future conditions (changes), e.g. condition of utility systems
   d. Planned modifications (both system locally and towards other systems)
   e. Planned operational changes implying new needs and increased load
   f. Future manning situation
   g. Future competence situation
   h. Availability of spare parts
   i. Possible organisational changes

j. Planned use of new technology.

4. Requirements of current regulations:
   a. Current regulations and requirements, and compliance with these
   b. Requirements on outdated equipment that will still be in use
   c. Planned/ongoing revisions of requirements.

Current design must at least be acceptable to known future requirements with regard to safety, reliability and functionality.

As seen in Figure 3, data and information are input to the activities 2-5 of the described LE process.

2.4 System breakdown and criticality (primary) screening

The LE process can be very time consuming and require a lot of resources. It is neither practicable nor necessary to perform analyses for all SSC. Resources should concentrate on SSC that have an impact (directly or indirectly) on safety. Thus, an extensive screening of functions/equipment should be carried out to decide which have to be analysed in detail Activity 2, see Figure 3). This section describes a primary screening based on criticality.

2.4.1 System breakdown structure

A screening is closely related to a system or function breakdown. The system breakdown is illustrated in Figure 4. In this figure there are three levels, but the numbers of levels will vary. As an example, a breakdown of a fire detection system and fire extinguishing system is shown below.

It should be noted that possible CCF must be taken into account, e.g. a common cause failure of several component may give rise to a failure of a subsystem. Thus, CCF must be evaluated one level higher. (CCF is described in section 2.7.)

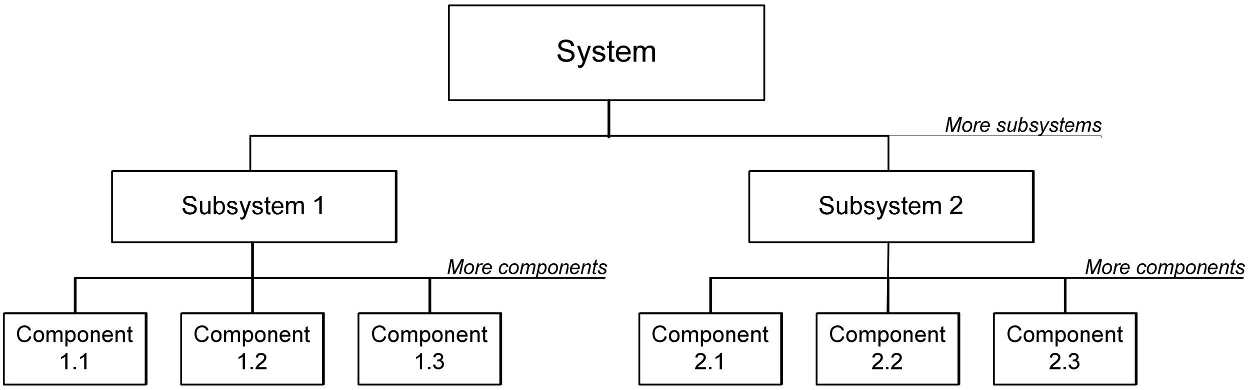


Figure 4: System breakdown structure, adapted from [73].

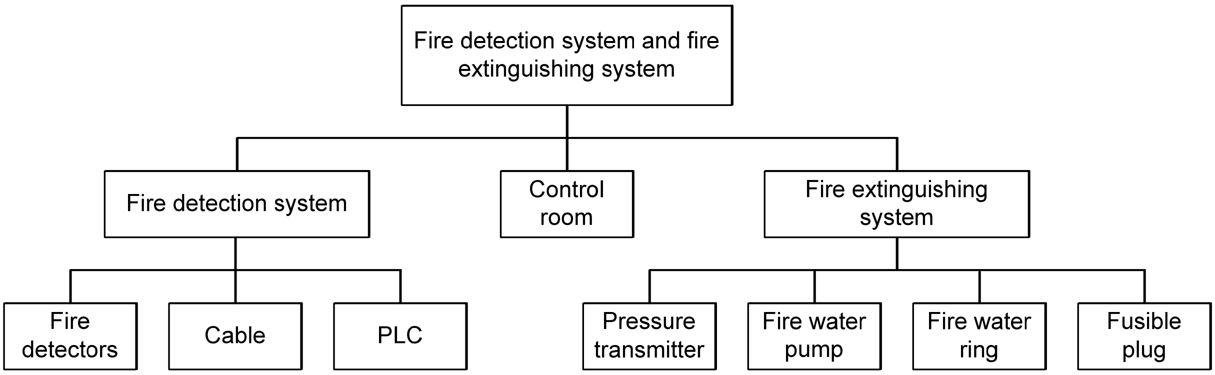


Figure 5: Example of system breakdown for a fire detection- and extinguishing system

2.4.2 Main systems on a facility

With regard to *System description and breakdown*, we note that the following are considered to be the main "systems" of an offshore facility:

1. Structures
2. Wells
3. Pipelines, risers and subsea systems
4. Process equipment
5. Safety systems
6. Material handling
7. Marine systems.

System 1 (Structures) has been treated quite extensively in the literature ([14], [56], [69] and [85] are some documents which focus mainly structures). Hence, structures have not been discussed in this report. Systems 2-5 are discussed, mainly with respect to physical ageing/material degradation; see Chapters 6-9. System 6 (Cranes and lifting equipment) is discussed mainly with respect to obsolescence and operational challenges and in the context of material handling; see Chapter 5. Some challenges related to obsolescence and human and organisational issues are also mentioned in Chapter 4.

In the discussions of Chapters 6-9, each system will be broken down into subsystems, following a "barrier line of thinking", and following the relevant NORSOK standards for the respective system. Without providing a precise definition of the barrier concept, we focus on physical barriers related to the actual equipment and barrier systems (i.e. complete system, implementing a safety function, and consisting of "barrier elements"). In a complete analysis of physical ageing, the level of breakdown should proceed until we arrive at units with unique degradation mechanisms.

2.4.3 Criticality classification and primary screening

The screening of activity 2 is based on a criticality classification of the SSC according to the consequences of possible SSC failures. This is a risk based approach inspired by NORSOK Z-008.

NORSOK Z-008 (ref. [51]) presents a platform for risk based decisions related to the management of maintenance activities. The standard states that preventive maintenance activities should be based on (cf. Section 4.2 in [51]):

1. Consequences of failures
2. Probability of failure
3. Redundancy[1]
4. Detectability of failure and failure mechanisms, including the time available to make necessary risk reducing measures to avoid critical function or sub-function faults
5. Cost of alternative preventive activities
6. Required availability of safety critical functions.

These points are also relevant for the classification and screening of an LE process:

- No. 1-3 are related to *risk* and will be considered in the (primary) screening (see below).
- No. 4 is related to *detectability* of state and *accessibility* of an item and will be used in a second step of screening when material degradation is an issue (Section 2.5.1).
- No. 5 is related to acceptance and cost-benefit. In practice, a specific risk reducing measure may not be practical (feasible) due to high costs; (and the ALARP principle may be used to arrive at a decision). Note that cost is not an issue in the present report.
- No. 6 relates to reliability of safety critical functions and will mainly be addressed in Chapter 9 when safety systems are treated.

The main point is that risk is the major criteria for the primary screening. In particular it is important that risk related to major hazards (e.g. fire/explosion, dropped objects, structural collapse), does not increase as a consequence of ageing or in the LE period.

Risk depends on both probability and consequence. However, the criticality analysis of NORSOK Z-008 focuses on the *consequences* of loss of *functions*, (Section 4.2 of [51]), as the consequence is independent of the equipment carrying out the functions. Tables 1-3 in that document provide a general criticality classification (High, Medium, Low), according to the potential for (i.e. possibility of) for serious consequences, with respect to HSE:

- High:
  - Potential for serious personnel injuries
  - Render safety critical systems inoperable
  - Potential for fire in classified areas
  - Potential for large pollution.
- Medium:
  - Potential for injuries requiring medical treatment
  - Limited effect on safety systems
  - No potential for fire in classified areas
  - Potential for moderate pollution.
- Low:
  - No potential for injuries
  - No potential for fire or effect on safety systems
  - No potential for pollution.

Such a classification could work for the LE process, too. If the consequence for a function/system or SSC falls within the category *High*, further analysis is required and the probability must also be assessed. To conclude, the following criticality (primary) screening applies to the LE process:

[1] Ageing may increase the probability of CCFs, e.g. simultaneous degradation of redundant components, unsatisfactory skills on a type of component. Therefore, in the screening of SSC for ageing components it is questionable if redundancy should be taken into account. Ref. [28].

- If the consequence category of the function/SSC is high, it is required to carry out detailed analyses to verify that safety is not compromised.
- If the consequence category is medium/low, it is not mandatory to carry out a detailed analysis, (as the main focus is on the risk of major hazards); instead it could be sufficient to rely on the current safety management / maintenance management systems.

This is rather similar to the screening process suggested in the IAEA Safety Standard, [28], (see their Fig.3; cf. Appendix B of the present report), which is based on the questions:

1. Would the failure of a system or structure result – directly or indirectly – in the loss or impairment of a safety function?
2. Would the failure of a structure element or component result – directly or indirectly – in the loss or impairment of a safety function?
3. Does ageing degradation have the possibility to cause failure of the structural element or component?

Further, we refer to the screening approach given in Chapter 4 of the IAEA report on safe long term operation, [29].

The criticality evaluation indicated here provides the main criteria for the screening, as it identifies the SSC for which (detailed) analyses are required. As stated above, an additional secondary screening should be carried out when material degradation is considered.

2.5 Secondary screening and detailed analysis for material degradation

The criticality screening (Section 2.4) is followed by activity 3, Analysis of failures and challenges and activity 4, Risk reducing measures (ref. Figure 3). The approach is somewhat different for the investigation of Material degradation (A), Obsolescence (B) and Organisational issues (C).

The identification of challenges with respect to material degradation includes a second screening and the analyses are also different for aspects A and B/C, respectively. Activities 3-4 related to *material degradation* are outlined below, and are further discussed in Chapter 3.

2.5.1 Secondary screening

For those SSC that give rise to high risk based on the criticality screening, there should be a second screening, to decide whether possible material degradations of SSC are acceptable for LE. This secondary screening is based on the detectability of the state (with respect to *material degradation*) and accessibility of the SSC. In particular, systems that are inaccessible for continuous and detailed inspection to assess their state, should be subject to detailed analysis with respect to possible degradation during the LE assessment.

It is essential to be able to inspect the SSC in order to (continuously) obtain knowledge about its “true” state with respect to degradation. If the equipment is readily accessible to obtain such knowledge at present and during the possible period of LE, a less detailed analysis may be required. The critical SSC should therefore be categorised according to

- *Availability for inspection/monitoring* of the SSC, to obtain knowledge about its current state.
- *Accessibility for maintenance and/or modification* of the SSC.

Thus, there are four categories of SSC, leading to different level of detail for analysis:

a. The SSC we can inspect ("see") *and* repair/replace; e.g. topside choke valves or gas detectors. For such SSC we should provide a model to predict the degradation/reliability for the entire LE period. The model can be updated continuously, based on actual data, from which we can decide when the SSC should be replaced/modified etc.

b. The SSC we can inspect but not repair/replace; e.g. bearing structure and piping. Also for such SSC the models to predict the degradation/reliability can be updated continuously. Based on this information one make decisions on whether operation can be continued/extended.

c. The SSC we can neither inspect nor repair/replace; e.g. casing. For such SSC we are completely depending on models to predict the degradation/reliability and make decisions. The models cannot be updated, i.e. the "best" model is expected to be the design life model.

d. The SSC that we can repair/replace but are unable to inspect, (in advance we will not know the effect of any maintenance action); e.g. flexible pipes from wells to FPSO. Models to predict the degradation are of limited value.

2.5.2 Models for detailed analyses

There are two categories of models applied for the failure analyses; deterministic (i.e. of the physical degradation) and probabilistic (considering failure rate etc.)

Deterministic modelling
The material degradation process can be assessed by considering e.g.:

- Relevant degradation mechanism(s)
- Process parameters and operational/design parameters, being important for the state of the SSC
- Failure modes
- Material properties
- Maintenance and modifications.

Probabilistic modelling
Also various probabilistic models are applicable, possibly in combination with models for material degradation. The probabilistic models provide direct input to the risk model; in particular to the probability of failure (or failure rate). The types of applicable models are restricted by the questions posed in section 2.5. In short the following models apply:

- *Life time models*; i.e. models for the time to first failure; often expressed as a model for the failure rate.
- *Models for the failure rate function* (of repairable units).
- *Models for the state of the SS.C*

2.5.3 Risk reducing measures with respect to physical ageing

The effect of various risk reducing measures (activity 4) have to be analysed: increased testing, replacement etc.

The reference [65] discusses life extension assessment with respect to cost, and compares four possible philosophies for LE of a component (also applicable to functions or systems):

- Use-up, i.e. using the equipment until the end of service life.
- Refurbishment, i.e. the existing equipment is fully overhauled and restored to an “as new” condition, but with old technology. This option is possible as long as spare parts, support, services and equipment knowledge is available.
- Retrofit, i.e. one or more of the main components are replaced with modern equivalents.
- Replacement.

The alternatives decided for the equipment depend on a number of factors, such as

- Actual length of the life extension period
- Cost
- Maintainability
- Spare parts
- Available data gathered during service.

Section 3.2 gives a presentation of various maintenance actions and compensating measures. This is partly based on Appendix B.

2.6 Obsolescence and operational/organisational challenges

Identification of challenges, analyses of gaps and identification of measures related to obsolescence and organisational issues (activities 3-4) are briefly reviewed here. A more thorough discussion is given in Chapter 4. Further, note that management of obsolescence is treated in Chapter 5 of the IAEA Safety Standard, [28].

2.6.1 Identification of obsolescence challenges

As far as obsolescence is concerned, it is necessary to identify challenges related to

- *Requirements*. Do the various functions/systems satisfy all present regulations/ requirements? All dispensations/exemptions that have been granted for current operation must be identified.
- *New operational conditions and needs* anticipated for the LE period; (e.g. caused by end-of-life production).
- Equipment being or becoming “*out of date*”, possibly causing challenges, e.g. related to availability spare parts.
- Introduction of *new technology* foreseen for the LE period

2.6.2 Identification of organisational and human resources challenges

Possible organisational challenges during the LE period are related to:

- Possible reorganisations (e.g. introduction of IO or company merging)
- Maintaining personnel competence (cf. ageing of personnel)
- Transfer of knowledge in the LE period.

Note that obsolescence and human and organisational issues are closely related, e.g. new technology requires new competence of maintenance operators.

2.6.3 Analyses to resolve identified challenges

When challenges of obsolescence and organisational issues have been identified, we will have an overview of possible deviations (gaps) between

- the required state of the facility, according to current requirements and future operational needs, and
- the anticipated performance of the facility in the LE period.

Analyses must then be carried out to see how these gaps can be closed; deciding on possible compensating measures/actions (Activity 4). Thus, the outcome of this activiy will be a set of suggested compensating measures, together with information on which gap they possible can close and how they should be implemented and followed up.

2.7 Overall risk picture (for the LE period)

The LE process must verify that the risk level of the facility is within acceptable limits during the entire LE period, and that systems for following up and updating the analysis are in place. In particular, it is important that risk related to major hazards (e.g. fire/explosion, dropped objects, structural collapse) does not increase as a consequence of LE.

When a set of compensating measures are identified and their risk reducing effect are analysed, one should do an overall evaluation of the risk picture of the facility, and verify that LE will not compromise safety at any time during LE, given that (if necessary) a prioritised sample of risk reducing measures are implemented (Activity 6 of the LE process). Here it is important that the time aspects of the measures are taken into account, i.e. how long will it take until the measure will have the estimated risk reducing effect? Both short-term and long-term measures may be a supplementary prerequisite to ensure that gaps are closed throughout the entire LE period. If safety is not found acceptable throughout the entire period, one must return to the previous step, (cf. Figure 3), for further identification of risk reducing measures.

The assessment of the risk picture, considering the anticipated *state during the LE period and at the end of the LE period,* should assess

a. Probability of major hazardous events (also considering the ageing to come).
b. Consequences of the hazardous events. Various consequences should be considered. (risk to personnel, environment and economy).
c. Total risk (related to major hazards) of the facility.
d. Changes in the risk level at the end of LE period, as compared with the (historic) risk during the operational phase.
e. Important assumptions and prerequisites in the analyses that must be followed up during the LE period.

Hazardous events and safety barriers

It is a main objective of the LE process to prevent that LE will increase the probability of major hazards. For instance, [87] discusses the significance for ageing of the following hazards (cf. Appendix B.6):

- HC leak
- Fire/explosion (usually as a consequence of a HC leak)
- Dropped object

- Structural collapse of topsides or topside equipment.

Thus, the risk assessment should focus on whether LE will increase the probability (or consequence) and thereby the risk caused by these hazardous events. It is also important to assess whether failure of specific SSC can *lead to* any major hazard. Important safety barriers must not be corrupted during LE, and all safety barriers related to major hazardous events must be investigated.

Also note that for *safety systems* (cf. Chapter 9) the *frequency of major hazardous* events is a relevant parameter in the risk estimation. For systems that are barriers against hazardous events, it is the *product* of the hazard frequency and the probability of system failure (PoF) that is most relevant, (and not PoF alone).

Common Cause Failures (CCF)
CCF (or more generally dependent failures) are important for the risk evaluations, in particular for redundant equipment. There are various types of dependencies, (see [20]), e.g.

- Physical dependencies
- Functional dependencies
- Location/environmental dependencies
- Plant configuration related dependencies
- Human dependencies.

In general a CCF analysis should consider failures due to common causes/stresses, (incl. common maintenance personnel) and possible “domino effects”. The common ageing of various SSC on a facility during the LE period, possibly resulting in a common (sudden) increase in the failure rate, can result in dependencies being relevant for the evaluation of risk throughout the LE period. We also know that there are a number of factors that will affect the barriers. Some *risk influencing factors* (in addition to the operational conditions) are given in Appendix B.5.2.

Observe that [20] refers to protections against CCF; diversity and separation (in time and space) being the most well known means of protection.

Risk estimation
Risk is given as a combination of the probability of failure (PoF) and the consequence of failure (CoF), and we can use a risk matrix to describe the risk related to failure of various systems. Table 1 shows the matrix used to define the risk based on PoF and CoF, here suggesting five classes for both PoF and CoF. Further, there is suggested four risk classes: low (L), medium (M), high (H) and very high (VH).

Table 1: Risk matrix (Example)

	PoF – category				
CoF-category	**1**	**2**	**3**	**4**	**5**
1	L	L	L	M	M
2	L	L	M	M	H
3	L	M	M	H	H
4	M	M	H	H	VH
5	M	H	H	VH	VH

The risk estimation may be quite *uncertain*, e.g. due to difficulty of predicting the future state of some equipment. If PoF and/or CoF are considered to be very uncertain, one should not use “best estimate” of these; but rather apply more conservative values. That is, uncertainty about estimated values should result in a higher risk estimate.

Rather than *quantifying* PoF and CoF, we could use a semi-quantitative approach to present risk related to major hazards, by defining some frequency and consequence categories/classes.

In order to estimate PoF of the major hazards, the probabilities should be split into the various contributions/causes (as various types of SSC failure). For equipment subject to material degradation it can be difficult to estimate the failure probability, especially future values. Thus, it may be easier to first assess the level of degradation, and then give the PoF category relative to this degree of degradation.

Considering CoF, there are various “dimensions” of the consequences to consider. For instance, CoF can be related to on the following aspects (*dimensions*):

- Personnel (life and health)
- Environment
- Economy
- Reputation.

The categorisation of CoF values can be based on the set of consequence classes given in NORSOK Z-008 ([51]), ref. section 2.4.3. Also Section B2 in the standard gives an example of consequence classes for pollution.

Risk evaluation

Based on the risk estimation it should be decided whether LE is feasible for the facility (with the suggested risk reducing measures). Thus, also risk acceptance criteria could be defined relative to the risk matrix. Often the ALARP approach is chosen, defining three risk levels:

- Green: Risk is acceptable.
- Yellow: Risk should be reduced “as low as reasonably practicable (considering cost/benefit).
- Red: Risk is unacceptable.

By inserting these colors into the risk matrix it will also serve risk evaluation (see table below):

Table 2: Risk evaluation (Example)

	PoF – category				
CoF-category	**1**	**2**	**3**	**4**	**5**
1					
2					
3					
4					
5					

These acceptance limits should be determined by a thorough discussion. Comparison with acceptable risk in future operation can help define the limits.

If risk is not in the green area, further risk reducing measures must be considered, and then a new risk assessment must be carried out. The final risk evaluation (and risk acceptance) should be based on the highest estimated risk of the LE period, *conditional* on the assumption that risk reducing measures are carried out (e.g. more condition monitoring or more frequent inspection).

2.8 LE management plan

When the risk assessment and the implementation of the elected measures return an acceptable result, it is required to work out a management plan for the LE. Now we have a final “action plan” consisting of

1. Risk reducing measures (maintenance, modifications and other compensating measures and defenses) that have to be carried out prior to initiating the LE
2. Risk reducing measures coming into action during the LE period, to be included in the LE management plan.

The plans for the LE period should specify e.g. the use of indicators, maintenance programmes, and procedures. The working out of an LE management plan should include

a. Maintenance programmes to ensure sufficient integrity, e.g. increased frequency of inspection/testing and needs for condition monitoring (of specific degradation mechanisms)
b. Specification of use of indicators during LE period
c. Plan to ensure sufficient competence for operation and maintenance
d. Plan to ensure that necessary spare parts are available throughout extended life
e. Overview of decisions and assumptions made (e.g. operational limitations), and how to follow up these

Issues a and b are discussed in Chapter 3; issues d and e will be discussed in Chapter 4, and issue c (indicators) will be further described in more detail below.

2.8.1 Indicators of ageing

To maintain safety it is very important to detect ageing effects of SSC to address associated reductions in safety margins and to take corrective actions before loss of integrity or functional capability occurs, [28]. Use of indicators to evaluate safety integrity is important for follow-up and decision making during operation of ageing facilities.

We define an indicator of ageing as a sign or evidence that some damage has already or is about to occur, and can be thought of as symptoms of ageing damage.

Table 3 presents some general indicators of ageing, (partly based on [23]). There are various types of indicators, e.g. specifying (in parenthesis indicating most relevant aspect of ageing management, A, B, C):

1. Inspection/monitoring results; (A)
2. The occurrence of specific failures/failure modes, (failure analysis); (A)
3. Number of various undesired events, (i.e. giving statistical trends); (A, B, C)
4. Reduced performance of process or quality of product is observed; (A, B, C)
5. Status with respect to obsolescence; (B)
6. Status with respect to organisation and human resources; (C).

In addition, experience from other similar equipment should be evaluated if available. See also Appendix B.5.4 where literature on indicators is reviewed.

Table 3: Examples of indicators for ageing

Indicator	Details	Comment
1. ***Inspection/monitoring of physical parameters; (A)***		
Parameter monitoring	Temperature, vibration, etc.	Can indicate the actual equipment condition and any damage. Trends can be determined from repeat inspection data.
"Visual" inspection	Temperature, vibration, noise, smell.	-
	Blistering or damage to surfaces.	Paint blistering or other surface damage indicates that some degradation may be occurring.
	Condition of paint and surface coatings.	Can demonstrate a lack of proper maintenance; increases the risk of corrosion.
Physical measuring	Measuring bearings, internal surfaces.	-
Sampling	Oil degradation/contamination, changes in operational condition.	-
Failure modes	E.g. leakages.	Leakage may be due to lack of maintenance or it may indicate more serious damage such as through-wall crack.
2. ***Failure analysis; (A)***		
Failing components		Carefully examined in search for ageing phenomena.
Old components		Carefully examined in search for ageing phenomena.
3. ***Statistics: Number of incidents/undesired events; (A,B,C)***		
Equipment age	Time in operation, total equipment age, equipment designed and manufactured to old codes.	Ref. Table 33, Appendix B.
Number of incidents during operation	Leaks, unplanned shut downs.	May be due to lack of maintenance (e.g. replacement of seals or gaskets), or it may indicate more serious damage such as a through-wall crack.
Number of repairs	Breakdowns, failures, defects, repairs.	May indicate that ageing challenges are already occurring. Should establish the underlying reasons for breakdowns/repairs.
4. ***Performance of process, or quality of product; (A,B,C)***		
Lack of process stability or	Operation outside design specification.	Excursions from the normal process operating envelope may mean that the equipment has deteriorated.
Instrumentation	Lack of consistency in the behaviour of process instrumentation.	Can suggest process instability. May indicate that the equipment has deteriorated or a fault with the instrumentation.
Reduction in plant efficiency	Pumping capability or heat up rates.	Can be due to factors such as product fouling or scaling.
Product quality	Impurities in the product from plant materials, outdated	Can indicate corrosion or erosion. An on-going product quality review can detect

Indicator	Details	Comment
	materials, welding quality.	variations in product quality.
Backlogs		Indication of maintenance quality.
5. Status with respect to obsolescence; (B)		
Dispensation	No. of dispensations per year.	-
New regulations	No. of new regulations per year.	-
Emergency preparedness	No. of emergency preparedness exercises per year.	-
Outdated technology	Equipment downtime due to ageing. Amount of available spare parts.	-
Modifications	No. of modifications due to new equipment.	-
6.Status with respect to organisation and human resources; (C)		
Facility competence	Average years with relevant experience (per person). Average years until retirement (per person). Total time of experience on (new) equipment.	-
External needs	Average personnel on board Availability of maintenance personnel.	As equipment ages, more maintenance is required, and maintenance personnel/crew are more often on facility.

2.9 Uncertainties related to LE

Uncertainties exist due to natural variation, physical uncertainty or randomness in the basic variables (Type I), and those due to factors that are a function of lack of complete understanding or knowledge (Type II). It can be seen that the uncertainties in the LE process include both Type I and II, [65].

As a facility ages, it may be that there is improved knowledge of the environment (reducing Type II) and there may also be improved knowledge of the loading from the environment (also Type II) particularly if some form of correlation between, for example wave height and stresses in primary elements is available. On the other hand, there is limited knowledge of wear-out failures, new technology, combination of existing and new technology etc. The various uncertainties of course are important, e.g. as they may infer a lack of robustness.

Analysis capabilities may have improved, but often there is insufficient data to support the analyses and to predict a future state of an SSC.

There are a number of gaps and limitations in knowledge with respect to ageing and LE, the main points being (mainly based on [65])

- Lack of a clearly defined and specified design life for the safety critical elements of offshore facilities
- Lack of full recognition of the significance of ageing processes (especially related to fatigue and corrosion) in connection with life extension beyond original design life
- Lack of a long term safety review of the safety critical elements for life extension. Limited application of modern codes and standards for reassessing design fatigue life and utilisation, taking account of appropriate design fatigue factors

- Lack of awareness of the possible ageing challenges, including all degradation mechanisms, failure modes, obsolescence challenges and organisational issues.
- Lack of additional measures for the management of the ageing challenges and limited recognition of the benefits that preventive maintenance and other reasonably practicable measures can have in expediting life extension.
- Limited monitoring, recording and taking full account of accumulated accidental damage
- Limited optimisation of the design and operation to ensure life extension is feasible
- Uncertainty about
    - Degradation mechanisms and ageing effects
    - Predictions of future state
    - Dependencies/Interactions and probability of common cause failures
    - Acceptance criteria and threshold values for screening, risk assessment, etc.
    - Risk influencing factors
    - Effect of risk reducing measures
- Failure rates are not necessarily constant as ageing develops.
- Updating of documentation is a challenge for most of the older installations and 100 per cent updating of documentation is not so likely, giving incorrect documentation, [60].

3 Analyses of material degradation

This chapter elaborates on topics relevant for the investigation of material degradation (cf activities 3-4 of Figure 3). Section 3.1 gives an overview of degradation mechanisms and information required to assess the state of degradation. Relevant maintenance and compensating measures are also outlined. The screening with respect to analysis of material degradation is discussed, and both deterministic/physical and probabilistic models for degradation are reviewed. In this chapter the assessment is more on a component level than on a system level (ref. Figure 4).

Some of the following discussions will distinguish between *active* and *passive* SSC; therefore, a brief introduction to these concepts is given.

Active and passive SSC
The ageing and LE literature in the nuclear industry makes a distinction between *active* and *passive* SSC regarding the treatment of life extension. The passive SSC perform their function without configuration or properties being changed; (static structures, vessels, piping, pump and valve bodies, electrical insulation, cabinets, etc. are typical examples). The active SSC will experience some kind of movement, actuation or change in state as part of their functioning; (valves, pumps, compressors, power supplies, switches, batteries, etc. are typical examples), see [87]. Reference is also made to the end of Appendix B.1, regarding the interpretation of active and passive SSC.

3.1 Assessment of physical state

It is an important task to assess the *present* physical state of SSC, and further to predict the *future* state of degradation. This section gives a list of important degradation mechanisms, which provides an important basis for further discussions. Related failure modes and process parameters and operational condition, which affect the degradation mechanisms, are also given. Finally, we give a tentative list of information needed to assess the state of degradation.

Information on typical degradation mechanisms and failure modes for various materials can also be found on www.exprobase.com [16].

3.1.1 Degradation mechanisms

Good knowledge of the degradation mechanisms is fundamental for establishing a reliable LE process. The most relevant degradation mechanisms related to aging are described in the following. Their relative importance (frequency) has been market according to: I – Most important, II – Important, III – Less Important.

A. Blockage (III) – process equipment like pipe work, valves, heat exchanger tubes and pressure relief systems can be blocked (partly or complete) because of scaling, fouling or build up of corrosion products.

B. Corrosion (I) – Degradation of material due to interaction with the environment leading to a loss of material and/or desirable properties of the material. Corrosion can be general, occur over a wide area, or be localised. Corrosion of a component can be **internal** or **external**. Corrosion can be divided into different forms. The most relevant corrosion forms in connection with oil and gas are:

1. **Bacterial:** Caused by availability of bacteria – most common Sulphate Reducing Bacteria (SRB)

2. **Crevice:** Localised corrosion in crevices or under deposits
3. **CUI:** Corrosion Under Insulation – a common corrosion issue normally associated with older equipment, where moisture trapped within insulation and lagging can cause corrosion of the metal surface.
4. **Galvanic:** Coupling between two different metals/alloys exposed in a common electrolyte
5. **General:** Even corrosion on the complete surface
6. **Pitting:** Localised corrosion attacks on active passive alloys (e.g. stainless steel)
7. S**CC:** Stress Corrosion Cracking – cracking due to the conjoint action of tensile stresses, and corrosion (anodic process), neither of which would cause cracking on their own – higher temperature gives more sensitivity.

C. Creep (III) – Continuous permanent deformation of a metal or other material at a load below the yield stress. In metals creep is usually a high temperature phenomenon, while plastics may creep to ambient temperatures

D. Flow induced metal loss (I) – The mechanical removal of material from a surface as a result of relative motion or impact from solids, liquids or vapour.

1. **Erosion from solids**: Mechanical removal of material due to solids in the fluid
2. **Flow induced erosion**: Mechanical removal of material due to the shear force between the surface and the fluid
3. **Cavitation**: Formation of vapour bubbles of a flowing liquid in a region where the pressure of the liquid falls below its vapour pressure – resulting in local metal loss where gas bubble collapse.

E. Fatigue (I) – Cracking under the influence of fluctuating stresses/cyclic load. These cyclic stresses can occur due to variations in pressure, temperature or other applied loads, and fatigue cracks often occur at stress concentrations. Fatigue crack propagation can continue until the flaw reaches a critical size that result in secondary failure. When fatigue develops with the combined effect of corrosion it is known as corrosion-fatigue.

1. **General**: Failure of welds and materials due to repeated application of cyclic stresses.
2. **Vibration**: High cycle low amplitude cyclic stresses due to poor fixing, resonance, such as in small bore piping attachments or free spanning pipelines.

F. Hydrogen related cracking (I) – Cracking due to the availability of atomic hydrogen in a metal. The most actual mechanisms in connection with oil and gas are:

1. **Blistering:** Dissolved atomic hydrogen recombines at inclusions in steels and results in surface blistering or internal cracking (known as Hydrogen (Pressure) Induced Cracking, or HIC/HPIC). When a residual or applied stress is present arrays of internal cracks can combine, which in conjunction with the low ductility, can lead to fracture. This is known as Stress Oriented Hydrogen Induced Cracking or SOHIC
2. **HE:** Hydrogen Embrittlement - loss of ductility in steel and some other alloys due to the presence of atomic hydrogen, often as a result of hydrogen being absorbed by the metal from a suitable environment e.g. welding, corrosion, cathodic protection (Hydrogen Induced Stress Cracking – HISC)
3. **SSC**: Sulphide Stress Cracking - Cracking caused by the impact of H_2S in the production fluid. The mechanism is a cathodic process. Is typical a low temperature (ambient) phenomenon

G. Material deterioration (I) – Loss of material properties as a combined effect of exposure period, temperature, environment and load pattern. This can include embrittlement of polymers (including elastomers), fibre composites, protective coatings and fire protection coatings.

This mechanism will also include metallic materials metallurgical aged under sustained stress, time and temperature following plastic deformation (e.g. a dent or pipeline installation by the reeling method).

H. Overload (II) – The actual load on the system is higher than according to design.

I. Physical damage (II) – damage such as dents and gouges due primarily to impact from dropped objects or as a result of maintenance. Damage can accumulate with age and operational cycling.

J. Temper/Thermal embrittlement (III) – Embrittlement of alloy steels caused by holding within, or cooling slowly through temperatures just below the transformation range, typically in excess of 500°C.

K. Wear (II) – Loss of material due to friction between moving parts, particularly in lifting equipment, valves, compressors, pumps etc. Abrasive wear, adhesive wear, fretting and wear assisted cracking (e.g. fretting fatigue) are the most frequently occurring wear mechanisms. Combination of relative movement, corrosion and fatigue can give an increased wear rate.

L. Temperature Expansion and Contraction (II) – Variations in the temperature (heating and cooling) can cause damage in the actual component or in connected equipment. *Wellhead growth* is one important example which can cause failure of wells. Pipeline walking is another example that may overload subsea spools and equipment.

M. Quick pressure change (increase or drop) **(III)** – Pressure changes due to changes in the operation. Can cause rupture in fibre reinforced plastic component ("hammering") and for pipes and vessels with internal lining due to pressure build up between layers (e.g. flexible pipes, water injection pipes with plastic liner).

N. Accumulated plastic deformation (III) (ratcheting) of pipe caused by cyclic loads leading to increased diameter or ovality.

3.1.2 Failure modes

In this section we list the failure modes that are related to ageing, i.e. safety critical failures of components/sub-systems/systems c*aused by the degradation mechanisms described in previous section* (in combination with special operational and process condition influencing the degradation or rate of degradation).

The main failure modes related to ageing are

1. Cracking and fracture; (e.g. fatigue damage and cracking, creep crack growth, SCC, stress influenced hydrogen cracking, brittle fracture, cleavage, ductile tearing)
2. Physical deformation; (e.g. dents, gouges, buckling, yielding, creep, (overload) fracture)
3. Burst;
4. Collapse;
5. Leakage;

6. Wall thinning; (e.g. due to corrosion, erosion, erosion-corrosion, scouring, wear, abrasion, fretting, over grinding)
7. Delamination; (e.g. for coating, insulation)
8. Malfunction; (e.g. for valves, sensors, etc.).

Note that the category “Malfunction” differs somewhat from the other failure modes, as it is very broad and could be related to any degradation mechanisms. It is usually applied for components/systems consisting of various parts, and the failure mode should be specified further for a specific component/system. Such specific failure modes (e.g. for valves and sensors) are given, for instance, in the OREDA handbooks, [63], [64]; see Appendix E for examples.

Note that the OREDA handbook also distinguishes between the *severity* of the failures:

- Critical
- Degraded
- Incipient.

Critical failure implies the loss of a main function. *Degraded* failure means that the component has a degraded state, requiring maintenance to avoid that the state develops further into a critical failure. *Incipient* failures could indicate initial degradation (or do not affect main functions of the component).

The modelling of the failure state going from *incipient*, via *degraded* to *critical* has been investigated by several authors, mostly applying Markov models. There are also some examples of analyses of actual offshore equipment, where this degradation is modelled (using actual data), see references in Section 3.4.

Table 4: Failure modes and degradations mechanisms

FAILURE MODE		**DEGRADATION MECHANISM**													
No	**DESCRIPTION**	**A- Blockage**	**B- Corrosion**	**C- Creep**	**D- Metal loss**	**E- Fatigue**	**F- Hyd.rel.cracking**	**G- M.deterioration**	**H- Overload**	**I- Phys.damage**	**J- Temp.embrittlem**	**K- Wear**	**L- Temp.expans.**	**M- Q.press.change**	**N- Accumulated plastic deformation**
1	Cracking and fracture	X	X	X	X	X	X	X	X	X	X	X	X	X	X
2	Physical deformation	X		X					X	X			X		X
3	Burst	X	X	X	X	X	X	X	X	X	X	X	X	X	X
4	Collapse		X	X	X	X		X	X	X			X	X	X
5	Leakage		X		X	X	X		X	X		X			
6	Wall-thinning		X	X	X			X				X			
7	Delamination		X					X						X	
8	Malfunction	X	X		X							X	X		

The degradation mechanisms described in Section 3.1.1 may cause or induce different types of failure modes. Table 4 below summarizes the relation between degradation mechanisms and failure modes. Again note that failure mode 8 is different from the others. We could actually make a distinction, and say that only failure modes 1-7 refer to “true” *material degradation*, (whilst all 8 failure modes relate to *physical ageing*). However, we will in this report mainly use these two terms interchangeably. *Further note that failure modes 1-7 are most relevant for passive components (e.g. structure, pipelines), while failure mode 8 (Malfunction) is most relevant for active components.*

3.1.3 Process parameters and operational conditions

In order to assess the state of the equipment, information is required on various parameters that influence the degradation process, i.e.

- *Process parameters*
- *Operation parameters*
- *Environmental / External impacts*
- *Design aspects*

PROCESS PARAMETERS

1. Fluid composition (oil / gas / water)
2. Temperature
3. Pressure / pressure impact
4. CO_2 content
5. H_2S content
6. pH
7. Oxygen
8. Water/brine salinity
9. Water content
10. Dew point
11. Velocity (flow rate)
12. Sand/Solid particles content
13. Wax content.

OPERATION PARAMETERS

1. Operation frequency (continuous or periodically)
2. Maintenance and testing frequency
3. Corrosion inhibitor
4. Chemical addition (composition and frequency)
5. Vibrations
6. Loads
    a. Environmental loads (i.e. wind, hydrodynamic, ice, earthquake)
    b. Functional loads (i.e. internal and external pressure loads)
    c. Interference loads (i.e. trawl interference, dropped object, anchoring)
7. Possibility of plugging of hydrates/asphaltenes
8. Operation pigging.

ENVIRONMENTAL / EXTERNAL ASPECTS

1. Earthquakes
2. Mudslides
3. Subsidence
4. Scouring

5. Geological changes
6. External loading
7. Radiation
8. Humidity
9. Salinity
10. Electrolyte composition
11. Presence of gases.

DESIGN ASPECTS, (these will essentially be treated under the system analyses; just giving a few examples here):

1. Use of gas lift
2. Use of water injection
3. Use of pressure control system (HIPPS)
4. Use of redundancy.

As operational conditions change, existing degradation mechanisms may accelerate or new degradation mechanism can occur. The following are typical challenges created by changes in the process fluid, [21]:

- Equipment designed for single phase flow may, in future, have to process multiphase flow either continuously or during transients.
- Compressors may not be able to handle increased differential pressure, lower flow rate or changes in molecular weight.
- Increases in levels of entrained CO_2 or H_2S can cause rapid increases in corrosion rated and can present an increased risk.
- A 10°C increase in operating temperature can double the corrosion rates.
- Increased solid content can result in more rapid erosion of pumps, valves and at pipe work bends.

Appendix B.5.3 gives references to various literature describing the effect of operational conditions. Table 5 gives a tentative summary of relations between degradation mechanisms (defined in Section 3.1.1) and various process and operational parameters.

Table 5: Degradations mechanisms affected by design / process/operation parameters

Degradation mechanism	**Process parameter**	**Operation parameter**
A. Blockage	Temperature, pressure, velocity, Solid particle content, flow rate,	Operation frequency, Possibility of plugging, operation pigging
B. Corrosion	Fluid composition, temperature, pressure, CO_2/H_2S content, pH, oxygen, water/brine salinity, water content, dew point, velocity, sand content, wax content,	Operation frequency, corrosion inhibitor, chemical addition, operation pigging
C. Creep	Temperature, pressure	Operation frequency, loads
D. Flow induced metal loss	Fluid composition, temperature, pressure, CO_2/H_2S content, pH, oxygen, water/brine salinity, water content, velocity, sand content, wax content,	Operation frequency, corrosion inhibitor, chemical addition, operation pigging
E. Fatigue	Pressure	Operation frequency, vibrations, loads
F. Hydrogen related cracking	Fluid composition, temperature, pressure, CO_2/H_2S content, pH, water/brine salinity, water content, velocity	Operation frequency, corrosion inhibitor, chemical addition, operation pigging

Degradation mechanism	Process parameter	Operation parameter
G. Material deterioration	Fluid composition, temperature, pressure, CO_2/H_2S content, pH, oxygen, water/brine salinity, water content, velocity, sand content	Operation frequency, corrosion inhibitor, chemical addition, operation pigging
H. Overload	Temperature, pressure	Loads
I. Physical damage	NA	Loads
J. Temp./thermal embrittlement	Temperature	Operation frequency
K. Wear	Temperature, pressure, CO_2/H_2S content, pH, oxygen, water/brine salinity, water content	Operation frequency, corrosion inhibitor, chemical addition, operation pigging
L. Temperature expan./contr.	Temperature, pressure	Operation frequency
M. Quick pressure change	Temperature, pressure	Operation frequency
N. Accumulated plastic deformation	Temperature, pressure	Operation frequency, loads

Which parameters to include in the analysis, will depend on the actual system and which materials are involved. It is not possible to give a general ranking of the importance of the different parameters.

3.1.4 Information required to assess state of degradation

This section sums up main information required to perform an assessment of the state of SSC. Ideally, the equipment records should contain all relevant information about the equipment. Thus, the design and manufacturing information should include design drawings, material mill and test certificates, welding and NDT specifications and reports, installation and commissioning tests, and quality assurance documents. Further, information on the operating instructions, and the duty and service history (being regularly updated) should be recorded. Also a list of maintenance activities (replacement parts, inspection reports, repairs, etc.) and modifications should be given.

The listing 1-15 below gives an overview of the type of information needed. For a real LE analysis one should prepare a more detailed list, describing what data to collect, at which "position", and at what stage to collect it, prior to the data collection.

DESIGN AND INSTALLATION PHASE

1. Information about actual material(s) including possible protection (e.g. coating, cathodic protection, inhibition)
2. Design life calculations
3. Drawings
4. Valid standards and recommended practices (RP)
5. Operation and process information (*at design phase*)
6. Information about installation loads
7. Installation accidents
8. As-installed and as-built documentation.

OPERATION PHASE (from start and until today)

9. Information about maintenance and modifications (including as-built documentation, failure data, failure modes, repairs, etc.)
10. Process- and operation parameters

11. Information from condition monitoring including indicators, trend analysis etc.
12. Information from inspection and testing
13. Information from "similar" operations (other facilities with similar equipment and operation history)
14. New and/or additional standards and Recommended Practices (RP) that have been implemented
15. New and/or additional tools/design methods/experience that have become available since the design phase.

During the life extension period there can be changes to the operations conditions that can have a significant impact on the technical integrity of the facilities, e.g. increases in temperature and pressure or changes in the composition of the produced fluid, [60].

Figure 6 shows the kind of information necessary for the evaluation of ageing and safety importance of components (from [15]).

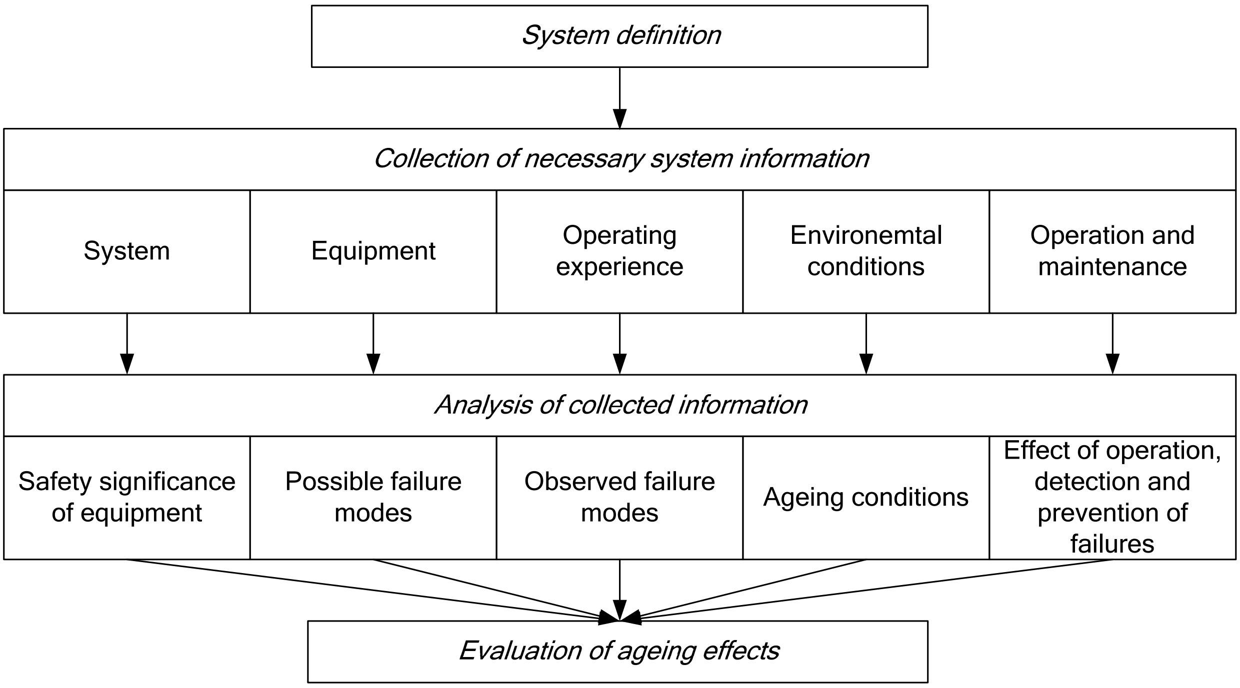


Figure 6: Required information for evaluation of ageing effects [15]

3.2 Maintenance and compensating measures

If LE is accepted for a facility, it will require various maintenance and compensating measures, which are compensating measures introduced to maintain a sufficient level of safety, (and pollution, economy etc). In particular it is important to decide on a maintenance programme to ensure technical integrity by LE of aging facilities. Testing, inspection and monitoring are required to identify the status of the equipment, and thus to perform the maintenance before (critical) failures occur. Some aspects are reviewed in this section.

3.2.1 Detection

Detection methods can include monitoring, testing, routine observation and (in-service) inspection. Some approaches for detection, relevant for various degradation mechanisms, are given in Table 6.

Table 6: Detection relevant for various degradations mechanisms, (partly based on [77])

Degradation mechanism	Detection
A. Blockage	Control system, testing, remote visual inspection
B. Corrosion	Tubing/Internal: (in-service) testing, Eddy Current testing General/External: Visual inspection, ultrasonic testing, penetrant testing
C. Creep	Visual inspection, magnetic particle testing, ultrasonic testing
D. Flow induced metal loss	In-service testing, ultrasonic testing
E. Fatigue	Visual inspection, vibration analysis, penetrant testing, magnetic particle testing, ultrasonic testing
F. Hydrogen related cracking	Visual inspection, leak detection, ultrasonic testing
G. Material deterioration	Visual inspection, ultrasonic testing
H. Overload	Testing
I. Physical damage	Visual inspection
J. Temp./thermal embrittlement	Thermography
K. Wear	Visual inspection, operational testing, in-service testing, repair, leak detection
L. Temperature expan./contr.	Visual inspection, thermography
M. Quick pressure change	Pressure control (alarm), control system
N. Accumulated plastic deformation	Visual inspection

For special NDT techniques and other techniques, we refer to [23], page 71-72 and page 129-132, or Appendix C in [77].

3.2.2 Monitoring

In the LE assessment, various information from parameters influence the degradation of a system/structure component. Essential information is also obtained through *monitoring*:

- Corrosion monitoring
  - Corrosion coupons / ER-probes / LPR probes
  - Sampling
- Wall thickness monitoring
- Cathodic Protection (CP) level monitoring
- Vibration monitoring
- Process monitoring (pressure, temperature, etc.)
- Loads monitoring
- Strain (including deflection) monitoring
- Thermal expansion monitoring
- Erosion / sand monitoring
- Microbial monitoring
- Settlement monitoring
- Span monitoring
- Fatigue monitoring
- Water uptake
- Diffusion.

Table 7: Monitoring for various degradations mechanisms (examples)

Degradation mechanism	Monitoring
A. Blockage	Pressure monitoring, process monitoring, settlement monitoring
B. Corrosion	Corrosion monitoring, wall thickness monitoring, microbial monitoring, CP monitoring
C. Creep	Strain monitoring
D. Flow induced metal loss	Wall thickness monitoring, wall thickness monitoring, erosion/sand monitoring
E. Fatigue	Fatigue monitoring, vibration monitoring, span monitoring, strain monitoring
F. Hydrogen related cracking	Corrosion monitoring, process monitoring
G. Material deterioration	Wall thickness monitoring, water uptake, diffusion
H. Overload	Load monitoring
I. Physical damage	Load monitoring, vibration monitoring
J. Temp./thermal embrittlem.	Process monitoring, thermal expansion monitoring
K. Wear	Wall thickness monitoring, pressure monitoring, vibration monitoring
L. Temperature expan./contr.	Process monitoring, strain monitoring
M. Quick pressure change	Process monitoring, pressure monitoring, strain monitoring
N. Accumulated plastic deformation	Process monitoring, strain monitoring

3.2.3 Maintenance and compensating measures

When state of degradation has been detected, there will be a need of compensating mesures (e.g. modifications) and preventive maintenance, e.g. considering

- Coating
- Material selection
- Cathodic protection
- Repair
- Change of process/operation parameters
- Chemical treatment
- Cleaning (e.g. high pressure water jetting).

Table 8 indicates how preventive maintenance and compensating measures can be related to the various degradation mechanisms.

Table 8: Preventive actions for various degradations mechanisms

Degradation mechanism	Maintenance and compensating measures	Comment and examples
A. Blockage	Cleaning, Chemical treatment Change process parameters	 Higher pressure
B. Corrosion	Coating, Chemical treatment Cathodic protection Change process parameters,	 Remove oxygen,
C. Creep	Repair and modification,	Reinforcement

Degradation mechanism	Maintenance and compensating measures	Comment and examples
	Change process parameters	Temperature
D. Flow induced metal loss	Change process parameters, Repair and modification	Pipe angle
E. Fatigue	Material selection, Change process parameters, Repair and modification	Change of load Necessary support
F. Hydrogen related cracking	Coating Material selection Change process parameters	Loads
G. Material deterioration	Material selection Change process/operation parameters	Temperature
H. Overload	Material selection Change process/operation parameters	Loads
I. Physical damage	Repair and modification Material selection	Protection structure
J. Temp./thermal embrittlem.	Material selection Change process/operation parameters	Temperature
K. Wear (friction?)	Coating Material selection Repair and modification	WC coating Change geometry
L. Temperature expan./contr.	Material selection Repair and modification Change process/operation parameters	
M. Delamination due to quick pressure change	Material selection Repair and modification Change process/operation parameters	
N. Accumulated plastic deformation	Material selection Repair and modification Change process/operation parameters	Change cyclic loads

Most maintenance actions and compensating measures described in the literature are technical and equipment specific methods. However, in general, important measures and preventive maintenance actions are

- Optimised inspection, monitoring and/or testing (both with respect to type and frequency of inspection/testing)
- Periodic evaluation of operating experience
- Design changes (e.g. new barriers)
- Replacements and/or repairs of specific equipment

Choice of method/measure is essentially related to system/type of equipment. However, Table 9 indicates most relevant maintenance methods and compensating measures for various degradation methods.

Table 9: Summary of maintenance actions and compensating measures for various degradation mechanisms

Degradation mechanism	Maintenance and compensating measures
A. Blockage	Monitoring and/or testing, design changes
B. Corrosion	Optimised inspection, monitoring and/or testing, periodic evaluation of operating experience, design changes, replacement and/or repair
C. Creep	Monitoring and/or testing, periodic evaluation of operating experience, design changes
D. Flow induced metal loss	Optimised inspection, monitoring and/or testing, periodic evaluation of operating experience, design changes
E. Fatigue	Optimised inspection, monitoring and/or testing, periodic evaluation of operating experience, design changes, replacement and/or repair
F. Hydrogen related cracking	Monitoring and/or testing, design changes, replacement and/or repair
G. Material deterioration	Design changes, replacement and/or repair
H. Overload	Design changes
I. Physical damage	Replacement and/or repair
J. Temp./thermal embrittlem.	Replacement and/or repair
K. Wear	Optimised inspection, monitoring and/or testing, replacement and/or repair
L. Temperature expan./contr.	Optimised inspection, monitoring and/or testing, design changes, replacement and/or repair
M. Quick pressure change	Design changes, replacement and/or repair
N. Accumulated plastic deformation	Optimised inspection, design changes, replacement and/or repair

3.3 Screening to analyse material degradation

As stated in Section 2.2 it is not necessary to analyse all SSC in detail with respect to material degradation. Thus, a (secondary) screening of SSC should be carried out during the LE process, (cf. activity 3 of Figure 3). This screening is based on the *detectability* of the state (with respect to *material degradation*) and *accessibility* of the SSC. It is suggested to categorise the critical SSC according to

- *Availability for inspection/monitoring* of the SSC, to obtain knowledge about its current state.
- *Accessibility for maintenance and/or modification* of the SSC.

This gives four categories of SSC, leading to different needs for detailed models/analyses during the LE assessment process.

A. The SSC can be inspected ("seen") *and* repaired/replaced:
For such SSC, we follow the state during the entire LE period, making the need of physical modelling less urgent. (If a model is designed, it can be updated continuously, based on actual data, making predictions more accurate.)

Examples of SSC in this category:

- Choke valve (topside): Can be inspected, (but this requires a production stop to be able to decompose the component). Replaceable.
- Sensor (e.g. gas detector, topside): Continuously sends signal that the sensor is functioning, and will therefore be intercepted when it stops sending signals. Replaceable.
- Centrifugal pump. Typical failure is mechanical seal leakage which will be detected only be looking and is possible to repair.
- Flanges
- Valves

B. <u>The SSC can be inspected but not repaired/replaced:</u>
Good prediction models are helpful, and the models to predict the degradation/reliability can also here be updated continuously. Based on this information one make decisions on whether operation can be continued/extended.

Examples of SSC within this category:

- Bearing structure under water. Can be inspected by divers or by ultrasound inspection. Not replaceable.
- Piping production/process. Can perform wall-thickness measurements. Such piping becomes degraded due to corrosion and erosion and sand production. To prevent the degradation either the production has to be reduced or a sand filter must be installed.
- Separator. Cost-benefit question if a new separator (system) should be installed or not.

C. <u>The SSC can neither be inspected nor repaired/replaced:</u>
For such SSC we are completely depending on models to predict the degradation/reliability and make decisions. Physical models are essential. The models cannot be updated, i.e. the "best" model can be the design life model; possibly supplemented with information from similar equipment (operating under similar conditions).

Examples of SSC within this category:

- Casing. Difficult to inspect (will only be able to inspect the inner casing). Not replaceable due to economical reasons, and more practicable to drill a new well.
- Bends (e.g. T-bends). Pigging to prevent corrosion not possible.
- Pipelines with varying diameter. Pigging to prevent corrosion not possible.

D. <u>The SSC can be repaired/replaced but can not be inspected, (i.e. in advance we will not know the effect of any maintenance actions and compensating measures):</u>
Here models to predict the degradation are of limited value.

Examples of SSC within this category:

- Flexible pipes, e.g. from well to FPSO (ref. section 7.1.2). The only way to inspect is by damaging the piping. Today it does not exist any preferred method to inspect such piping (in advance). The armor between the two plastic layers will degrade due to bending and water break-through can occur. If then the production is stopped, due to pressure relief this may lead to blistering due to gas in the armor.

In general, topside equipment is accessible and can be inspected and/or repaired while subsea equipment is more difficult and expensive both to inspect and repair, and some subsea equipment is not even replaceable.

So different level of detail of model/analysis is necessary, depending on which of the above four categories an SSC belongs to. The required need for detail analyses is illustrated in Figure 7. Red indicates need for detailed analyses, yellow indicates need for a more coarse analyses, while green indicates that there is probably no need for further analysis. We consider it to be more critical not to be able to inspect than not to be able to repair/replace. As long as it is possible to inspect or monitor when a failure occurs, one can respond on reducing the consequences of the failure (e.g. by a shut-down). If you are able to replace, but cannot monitor when a failure occurs – it may lead to more severe consequences before the failure is responded on. Therefore more detailed analyses are required for those SSC which are not able to be monitored.

		Knowledge?	
		Yes	No
Measures?	Yes	(green)	(red)
	No	(yellow)	(red)

Figure 7: Level of detail of analysis required for combinations of knowledge (ability to inspect) and possibilities for compensating measures. Red indicates high level of detail, yellow medium level and green low level.

The above figure gives a strict distinction between Yes and No for both *knowledge* and *measures*. In practice there is often a more gradual transition from *yes* to *no*, (as e.g. *some* information may be acquired with reasonable cost). We can have a certain knowledge of the condition of the SSC based on (partial) tests or inspections, or there are similar components on the facility having approximately the same operational characteristics that can be inspected. And for the possibilities for compensating measures, we may for example be able to increase the maintenance or even modify the equipment, but due to practicable or economical reasons we cannot replace the whole SSC. Thus, the *degree* of knowledge and compensating measures is somewhere between Yes and No.

Further, the possibilities for compensating measures should be based on what is practically possible to achieve, based on costs, competence, suppliers, spare parts, maintenance personnel, etc. Even if it is in theory possible to replace equipment, it may be needed to analyse the material degradation of the equipment any further, due to the fact that it is not cost-effective to replace it. In addition, there are intermediate cases. Thus, a more detailed matrix is suggested; see Figure 8, giving nine categories.

		Knowledge?		
		Good	Some	Poor
Measures?	Replace	**I**	**IV**	**VII**
	Some	**II**	**V**	**VIII**
	No	**III**	**VI**	**IX**

Figure 8: Example of a more detailed matrix for combinations of different levels of knowledge (ability to inspect) and possibilities for compensating measures.

The colours of this figure indicate the need of a detailed analysis of the SSC. Green (I, II) indicates no need of a new analysis; it could be sufficient to proceed with the current maintenance programme. Yellow (III, IV, V) indicates that a less detailed analysis may be required. Red (VI, VII, VIII, IX) indicates need of a detailed analysis.

However, this decision should also depend on the assessed current state of degradation. SSC that are found to have already reached a high level of degradation should be subject to a rather detailed analysis, even if it is categorised as *yellow* (and perhaps even *green*). So each SSC being categorised as critical in the primary screening, should be evaluated according to these criteria to decide on the need for further analyses.

There are two types of models to apply in the further analyses, i.e.

- models for physical degradation, (deterministic modelling) to assess the state of material degradation, or
- probabilistic modelling, e.g. also modelling maintenance activities.

The next step is to decide which of these (or both) models should be utilised. An ESReDA book, [15], suggests that this decision should depend on whether the SSC is *active* or *passive*, see Table 31 in Appendix B). Their suggestion is that active components (being operated), like valves, detectors and pumps, should be subject to probabilistic modelling, and that passive components, like pipelines, flanges and casing, should be subject to physical/deterministic modelling. This could serve as guidance to the choice of modelling. More general, if important failure modes are truly caused by material degradation, it is recommended to carry out an analysis based on a physical degradation model, (at least for SSC in red area). However, if *malfunction* is the main failure mode, (see failure mode no. 8 of Table 4 in Section 3.1.2) this gives a good argument in favor of a probabilistic modelling.

Note that, even if a physical modelling is chosen, we need a PoF (probability of failure) as input to the risk assessment (Section 2.7).

Figure 9 summarises the screening process and evaluation for material degradation. As was mentioned in section 3.1.2, failure modes caused by *degradation mechanisms* are most relevant for passive SSC while *malfunction* is a failure mode that is most relevant for active components. Thus, the text in the figure “Failure mode caused by degradation mechanisms or is malfunction the failure mode?” could be replaced by: “Is the SSC passive or active?”.

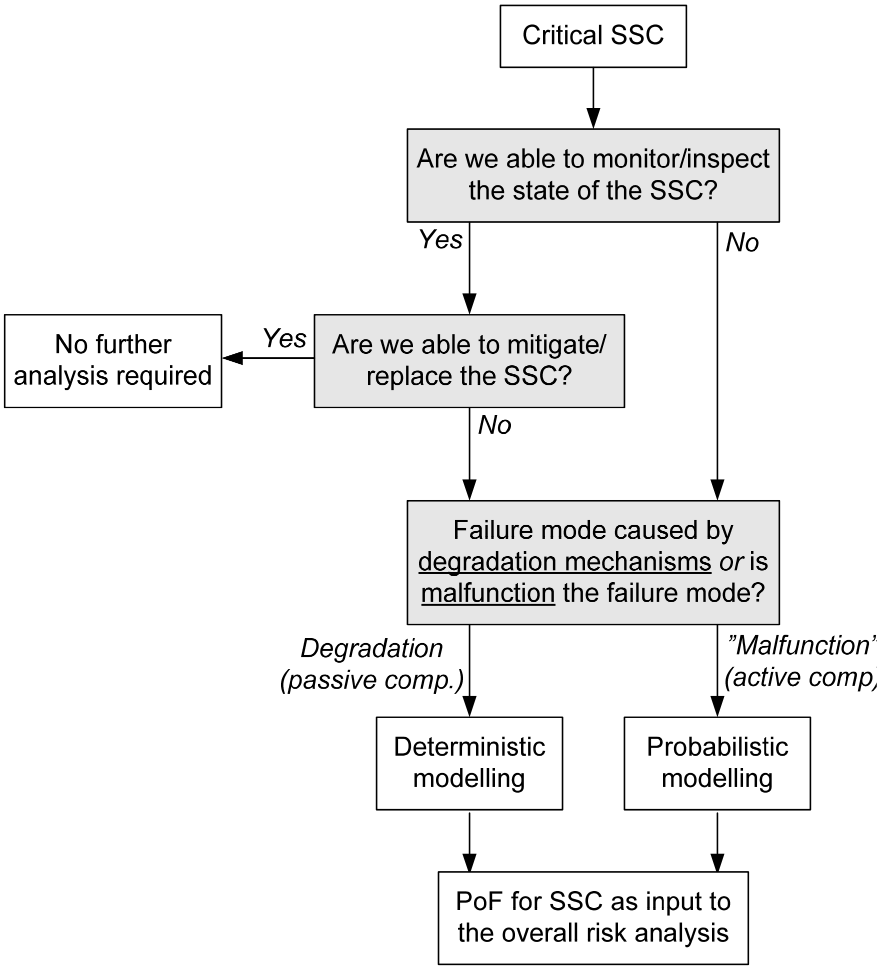


Figure 9: (Secondary) screening and analysis with respect to material degradation

3.4 Models for ageing

ESReDa, [15] refers to two approaches to analysing ageing, (Appendix B):

- Physically oriented (focusing on the degradation process)
- Reliability oriented

Some relevant models for these two approaches are reviewed below. We also include a short discussion on models including explanatory variables (*covariates*).

3.4.1 Analysis of physical degradation

The state of material degradation can be assessed by the following steps:

1. Find the degradation mechanism relevant for the SSC from the list of generic degradations mechanisms, and suggest their relations to various failure modes, (see Table 4 of Section 3.1.2).
2. Give an overview of process parameters and operational/design parameters, being important for the state of the SSC, (Section 3.1.3).
3. Estimate the present state with respect to the relevant degradation mechanisms and failure modes, and discuss the uncertainty about the estimated state.

4. Discuss future challenges related to the material degradation based on the material properties, degradation mechanisms, failure modes and maintenance activities.
5. Predict the state with respect to relevant degradation mechanisms and failure modes throughout or at the end of LE period, and discuss the uncertainty about the predicted state.

For those SSC that requires less detailed analyses (categorised in yellow in previous subsection), it is at least required to give an estimate of the present and future material states. Also a discussion of future challenges and possible degradations mechanisms is required.

To understand the process from incipient fault to propagation, to detect faults and anticipate their evolution, it is necessary to identify the degradation mechanism at work, and to have precise knowledge of the physical phenomena and the physical or statistical laws of degradation linked to the mechanism, [15].Figure 10 indicates a model for the level of degradation. In this particular case, a specific level of degradation defines "failure" (here *rupture*). This is not generally the case.

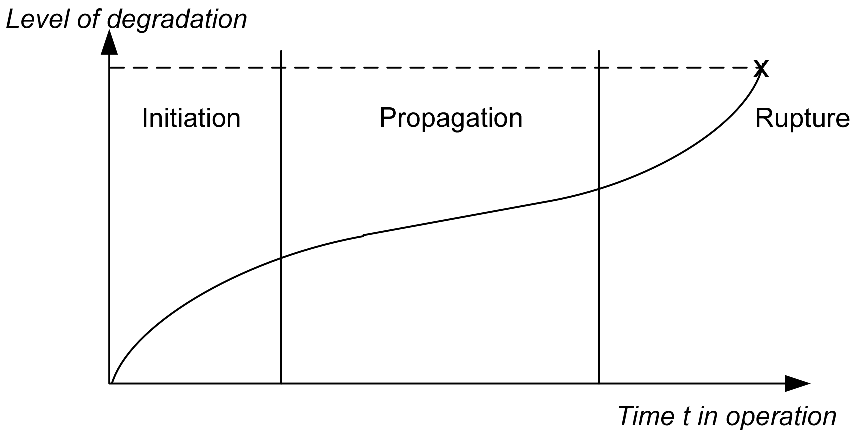


Figure 10: Evolution of level of degradation [15]

There is a considerable amount of literature discussing modelling of degradation mechanisms. Section 6.1.2 of [86] refers some models that have been suggested, in particular diffusion models with a drift function, g(t), where g(t) has different forms for various types of degradation e.g.

- Corrosion of steel not sufficiently protected by concrete or preservation
- Carbonation (a chemical degradation process)
- Crack development
- Shrinkage

Models are also suggested in [74], e.g. on the degradation of a pipeline, covering uniform corrosion and abrasive wear.

Further, the report [90] discusses some models which were related to the use of RBI (Risk Based Inspection); in particular considering probabilistic fatigue modelling. Finally, we refer to part III of [15].

Some of these models may have a probabilistic aspect, but are based on a physical understanding of the process.

3.4.2 Probabilistic modelling

Also various probabilistic models are applicable, possibly in combination with models for material degradation. The probabilistic models provide direct input to the risk model; in particular to the probability of failure (or failure rate). The types of applicable models are restricted by the questions posed in section 2.5. In short, the following models apply:

1. *Life time models*; i.e. models for the time to first failure; often expressed as a model for the failure rate. Typical example being a Weibull model, giving the failure rate as a function of time, *t*, (or for the probability of failing prior to a time instant, *t*). These are models for non-repairable units; and will thus apply for units that *can not be mitigated*. The models apply both if the unit can and can not be inspected. If the unit can be inspected, it is possible to let the failure probability/rate depend on the observed state.

2. *Models for the failure rate function* (of repairable units). This is often expressed as ROCOF (Rate of Occurrence of failure), which is a function both of time and maintenance strategy. So these models apply for units that can be maintained and where there are possibilities for compensating measures. Can be used both for units that can and can not be inspected. If the unit can be inspected, it is possible to model ROCOF to depend on the observed state.

3. *Markov models*. These probabilistic models defines a number of states depending on level of degradation (e.g. *perfect*, *degraded* and *failed*), and models the transition rates between the states. Most relevant for units that can be both inspected and repaired.

4. *Probability of Failure (POF) models*, expressing PoF directly in terms of level of degradation of unit. Applies for units that can be inspected.

The following should represent typical use of probabilistic models (relative to the classification in activity 3):

Not inspect/know (and not possibility for compensating measures):1. Life time
Not inspect/know (and possibility for compensating measures): 2. ROCOF
Inspect/know (and possibility for compensating measures): 3. Markov
Inspect/know (and not possibility for compensating measures): 4. PoF

Figure 7 illustrates which probabilistic method that is preferred for the various combinations of inspection and mitigation properties.

		Knowledge?	
		Yes	No
Measures?	Yes	**3. Markov**	**2. ROCOF**
	No	**1. Life time**	**4. PoF**

Figure 11: Typical use of probabilistic models for combinations of knowledge and possibilities for compensating measures

We note that it is often difficult to find reliable input data to the probabilistic models. In many cases we can inspect (see the state), and PoF could be a relatively simple option.

So the reliability-oriented concept of ageing is based on statistical (probabilistic) models and some additional information on models 1-3 are given below.

1. Life time models, The focus is on the failure rates (hazard rates) of the distribution, e.g. whether it is a bath tub curve, constant (meaning exponential model), Weibull, etc., e.g. see [73]. Examples of such failure rate models (life time models) are shown in Figure 12 below.

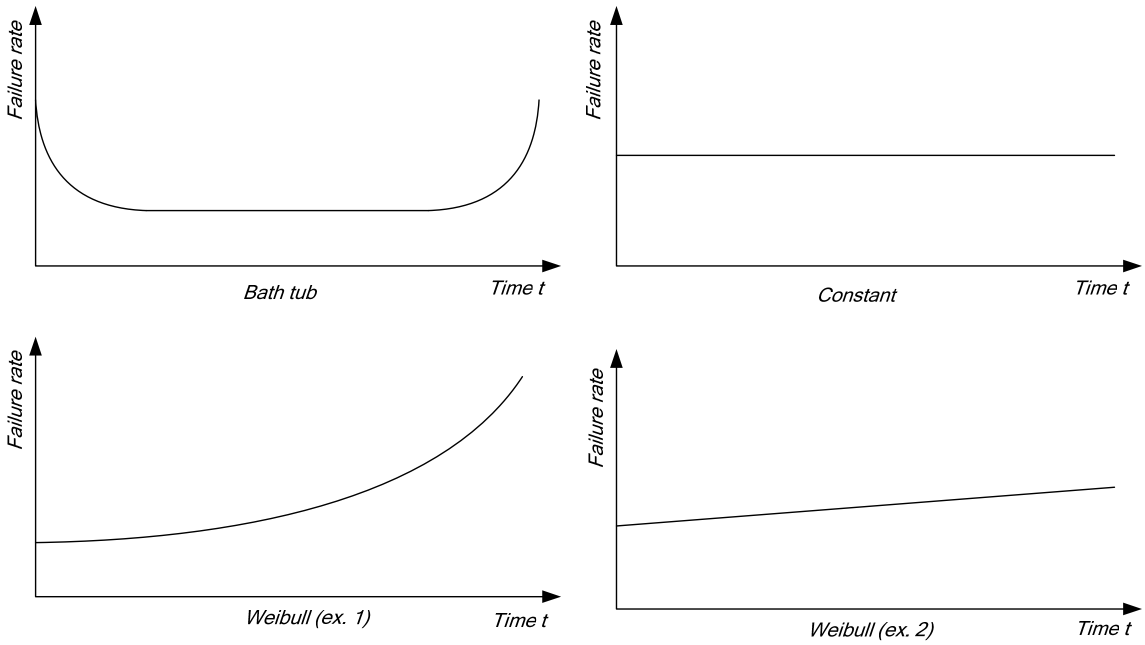


Figure 12: Examples of failure rate (life time) models

The failure rate (hazard rate) at time *t* gives the rate of failure of a component of age *t*, for which is known not to have failed up to this time *t*. This is the basic feature of these models. Typical assumptions in the use of these reliability models are:

- Electronic equipment has a constant failure rate (exponential model)
- Mechanical equipment: either bath tub form of failure rate or Weibull model

[71] proposes guidance for selection of life distributions for four different failure mechanisms, see Table 10.

Table 10: Failure mechanisms and life distributions [71]

Failure mechanism	Life distribution				
	Weibull	Lognormal	Inverse Gauss	Birnbaum-Saunders	Gumbel
Fatigue (cyclic)		X	X		
Fatigue (cum.)			X	X	
Corrosion (pitting)	X				X
Wear			X		

In [4] it is suggested that a slightly constant increasing failure rate model (ref. Weibull ex. 2 in Figure 12), called slow ageing in [4], for corrosion or creep. A constant failure rate (ref. Figure 12) is suggested for modelling ageing of electronic, electric, pneumatics, hydraulics and mechanical systems.

In [46] a number of areas of change within the field of physical asset management are discussed. One of these areas is the distribution of failures. As equipment grows and become more and more complex, items conform to failure probability patterns that are constant (with or without a burn-in period). This contradicts the belief that there is always a connection between reliability and operating age and [46] concludes that it is more conservative to assume that failures occur randomly rather then after some fixed amount of time in service. A predictable relationship between age and failure is true for some failure modes, and often associated with fatigue and corrosion. This means that unless there is a dominant age-related failure mode, fixed interval overhauls or replacements do little or nothing to improve the reliability of complex items.

[4] also points out that recent research into equipment failure probability and advanced age has shown that there is not a strong link between the two. There are several options of failure probability distributions as function of ageing, as proposed above. A ranking of six different failure distributions from least likely to most likely are proposed, and [4] suggests that the bathtub curve is the second least likely and that the constant curve with a burn-in period is the most likely.

2. ROCOF models. For repairable items, the failure intensity (or Rate Of Occurrence of Failure, ROCOF, is a more appropriate concept. This is the average failure rate of a group of components that has been in operation for a period *t*, (without specifying the exact history of a specific component with respect to failures/repairs). If we assume so-called “minimal repair”, it means that the ROCOF will actually follow the failure (hazard) rate of a new component. Otherwise the modelling of ROCOF becomes more complex, and in general it will depend heavily on the maintenance performed.

3. Markov models for the state of component, means that

- At least three states of component are defined: *New*, *degraded*, (critically) *failed*
- The transition rate out of a state is constant, (but differs from state to state)
- Total life time equals the sum of the durations in the various states until it fails (reaches the faulty state)
- Parameters by which we can define and observe the actual state must be defined.
- Frequent observations to decide the actual state must be done.

In a way this represents an intermediate modelling in between a pure reliability modelling and a physical modelling. The life time distribution modelling is based on the assumption that observations of the (physical) state can be obtained during the unit’s life time.

Figure 13 provides the simplest example. Here the component starts in OK state ("good as new"), and with a constant rate, λ_D, it will enter a degraded state (D). In this state the component maintains its main functions, but degradation may be observed, indicating a preventive maintenance (PM) should be carried out to avoid entering the state of a (critical) fault (C). Note that the figure just describes the degradation (and not change of state due to PM). When the component is in state D, there is a constant rate, λ_C for entering state C. If the component reaches state C it fails to carry out its main function, and corrective maintenance has to be carried out. Thus, the sojourn times in both OK and D states have an exponential distribution. This figure gives an example of a very simple phase type distribution [89].

If $\lambda_D = \lambda_C$ in this model the failure time distribution indicated by Figure 13 becomes a Gamma distribution. However, in this class of models it is usually most realistic to assume $\lambda_D << \lambda_C$. Further, this type of models is usually applied only if inspection/monitoring/testing are used to reveal that the component has reached state D.

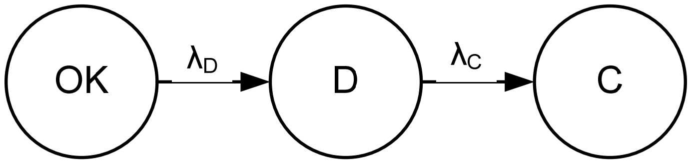


Figure 13: Illustration of a simple Markov process to describe a life time distribution based on degradation states

The figure exemplifies a Markov model. Examples of the use of these types of models, using actual offshore data, are given e.g. in [15], [16], [18]. A more advanced Markov modelling using inspection data from a railway line is given in [19].

A general class of models for *delay time analysis* was developed by [5] and [3]. The systems are regularly inspected with period, τ, and a main objective of their Delay Time Models (DTM) is to model the consequences of an inspection maintenance policy. A central concept is the *delay time*, which is the time elapsing from the instant where a deterioration could first be noticed until it reaches the failed state (F), and repair can no longer be delayed. A (preventive) repair may, therefore be undertaken any time within this period. *PM* (Preventive Maintenance) is assumed to consist primarily of a test resulting in replacement or repair of components that are in a state of deterioration.

Finally, [86] presented the use of Markov decision models in ageing management, representing a rather advanced approach.

4. PoF models

PoF models express PoF directly in terms of level of degradation of unit. Figure 14 illustrates the relationship between the level of degradation and a classification of the probability of failure into five distinct PoF classes. Any degradation that exceeds a certain level will belong to the highest PoF class (PoF 5 in the figure).

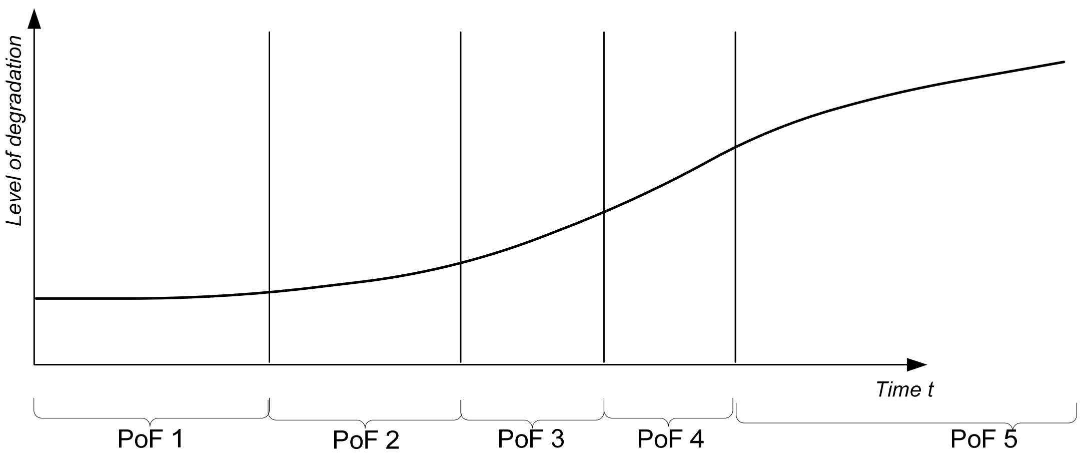


Figure 14: Relationship between level of degradation and PoF categories

3.4.3 Covariates

The above models could be extended by incorporating so-called *exploratory variables* (also called *covariates*). These could be various “risk factors” or (operational) parameters, see Appendix B.5.2 and B.5.3.

The effect of these can be modelled in various ways. Usually the model parameters (e.g. of the life time distribution) is allowed to depend on these operational parameters, e.g. see Chapter 12 of [73].

Another way of modelling the dependence of various factors is trough the use of Bayesian Networks [45] or risk influence diagrams.

3.5 Summary on LE assessment with respect to material degradation

A risk based approach on life extension of SSC which require further analyses with respect to material degradation, (based on a screening process described in section 2.5) can be carried out by the following approach:

1. Collect and analyse necessary background information from design, installation and operation – both historical information and for the extension period.
2. Assess today’s status with respect to degradation. Three possible conclusions and actions:
    - Unacceptable even after repair/modification -> Replace
    - Will be acceptable after repair/modification -> Repair/modify
    - Acceptable -> No modification required
3. Assess probability of failure, consequence of failure and resulting risk level valid for the extension period (based on information on future operation).
4. Develop a maintenance and modification plan (from the result of the risk evaluation) to operate at an acceptable risk level during the extension period. Is risk acceptable after implementation of maintenance and modification plan? Are there any constraints in future operation?
5. Implement the maintenance and modification plan and specifications for future operation.

Competence
This should give a consistent approach to analysis of material degradation independent of company or personnel involved. However, it is important that qualified people are involved in the evaluation. The analysis shall preferably involve experienced people within

- Design
- Operation (including maintenance and modifications)
- Process
- Material
- HSE

All the analysis work shall be well documented and traceable. This makes it easier to complete a re-analysis at a later stage.

3.6 Challenges and possible lack of knowledge

Good knowledge and modelling of degradation mechanisms are essential in the LE process. Some general questions and rather obvious challenges related to material degradation, are

- What are the degradation mechanisms for which it does not exist sufficiently good/established *models* to describe the degradation? What are the needs for improvements of these models?

- What are the best parameters/measurements to describe present *state* with respect to various degradation mechanisms? What is the availability of such measurements?

- Do we have sufficient knowledge about how operational/process conditions and parameters affect the degradation processes? Does it exist sufficiently good models for the effect of these parameters?

- Do we have sufficient knowledge and models for the effect of maintenance on the degradation process?

- When can a reliability oriented modelling be chosen instead of a physical oriented modelling? To what extent does it exist sufficiently good models and data to apply the reliability oriented approach?

- How to ensure a sufficient competence and knowledge of the operators to carry out the LE process?

- Are there good enough systems for data collection and sufficient use of field experience on degradation failures?

The relevance of these questions may depend on the actual systems, and how accessible they are for assessing their current state.

In chapters 6-9 challenges with respect to material degradation are exemplified for four main systems. Each example starts with a system description and an approach for including all relevant subsystems/-components. A barrier approach is chosen for the system breakdown/description. These chapters also include some system specific references.

4 Obsolescence and organisational challenges

This chapter elaborates on challenges and analyses relevant for obsolescence (B) and organisational issues (C), cf. activities 3 and 4 of Figure 3. Also the analyses of material degradation (A) may give useful input to the analyses of aspects B and C. Hence, the three topics must be seen in combination.

The present chapter is based on the general discussion in Chapter 2 and will treat

- Possible challenges related to obsolesence
- Possible challenges related to future operational changes
- Organisational issues
- Possible challenges related to human resources
- Analyses to resolve these challenges

The chapter presents relevant questions for an operator planning for LE. The last section gives examples, e.g. on emergency preparedness. Relevant issues for material handling and cranes is an example presented in the next chapter.

4.1 Overview of possible challenges

Possible obsolescence challenges
As a facility changes, equipment become outdated or new operations and/or new regulations require new techonology. With respect to obsolescence it is necessary to identify challenges related to

- *Requirements and regulations*. Do the various functions/systems satisfy all present regulations/ requirements? All dispensations/exemptions that have been granted for current operation must be identified.
- *Outdated technology*. Equipment being or becoming outdated, causing possible challenges e.g. with respect to availability spare parts.
- *New and advancing technology*. Introduction of new technology foreseen during the LE period.
- *Spare parts*. Availability of spare parts may become a challenge for older equipment.
- *New operational conditions and needs* anticipated during the LE period; (pressure, process liquid, etc, e.g. caused by end-of-life production).
- *Overall layout and space challenges on the facility*. More equipment on the facility may lead to layout and load challenges.

Each of these six challenges related to obsolescense are described in more detail in section 4.2.

Possible human and organisational challenges
A main question is whether sufficient human resources available to operate during the LE. Possible organisational challenges during the LE period are related to

- *Human resources*. Maintaining personnel competence (cf. ageing of personnel) and transfering knowledge during the LE period.
- Facility hand-over

- Sufficient competence available to carry out LE assessment and follow up during the LE period
- New types of operations, e.g. IO (Integrated Operations)
- Automatised operation and reduced manning
- Reorganisations, such as e.g. changes in ownership, changes in organisation structure, merging with other companies.

The above first three bullets are discussed in more detail in section 4.3.

4.2 Obsolescence

Requirements and regulations
When a facility reaches the end of service life, it is likely that regulations have been revised and that new performance standards have been issued after the facility was designed. Typical examples are new requirements related to environment and spills, new safety requirements, new technical requirements for equipment, requirements regarding modifications.

It is supposed that previous dispensations will not be valid for the LE period. Thus, the facility must follow the last revisions of regulations and performance standards, at least for the SSC that have an impact on the safety of the facility, (i.e. identified in a screening process, cf. Chapter 2). Relevant questions related to new requirements and regulations for these SSC are

- What are the relevant standards, regulations and requirements relevant for the SSC (incl. operation of the equipment)?
- Are there sufficient knowledge about the current regulations and requirements?
- Which original standards/regulations are still relevant (e.g. due to old technology)?
- Which deviations/gaps exist in relation to current standards, regulations and requirements?

Deviations from current regulations and standards are manifested through design weaknesses (e.g. in equipment qualification, separation, diversity or severe accident management capabilities). Subsequently, the facility’s safety level do not comply with specifiications of current standards and regulations, (e.g. weaknesses regarding *defence in depth*, or too high core damage frequency). Such deviations (or gaps) must be closed. Secondly, there is throughout the LE period a need of systematic reassessment of the facility against current standards, (e.g. periodic safety review), and approprate upgrading, backfitting or modernisation, [28].

Outdated technology (based on [21])
Given the age of the equipment, much of it was made by manufacturers who no longer exist or who are no longer prepared to support it into the future. This is most typical for the following equipment:

- Rotating equipment
- Electrical equipment, i.e. swithcgear
- Instrumentation
- Control systems and software.

It shoull be noted that continuing to operate outdated equipment may require a different operating and maintenance philosophy. Outdated equipment should be tested against the following questions:

- How reliable is it, and is it getting less reliable as time passes?

- Can the equipment be readily maintained?
- Are replacement parts and assemblies readily available or are they easily reverse engineered?
- Are there companies supporting the aftermarket with spares and overhaul capability?
- When making repairs to SSC, is there a possibility for further damage to be introduced (resulted from factors such as e.g. older materials being more difficult to weld than current materials and constraints of access for welding)? [23]
- As a facility ages, there is a trend that more and more equipment is replaced by temporary equipment instead of new equipment. Is the personnel competence sufficient on the temporary equipment?

Ageing equipment may be difficult to dismantle, e.g. due to corroded or distorted joints, lack of drawings, lack of special tools. Judgment is required to select the best replacement, which may not give the same results as the original and re-engineering, new skills and knowledge may be required, [23].

Equipment needing skills that are now rare or becoming obsolete presents another challenge. There may not be formal training available on ‘obsolete’ skills. Where particular techniques are required in order to continue to operate ageing equipment, deliberate effort is needed to retain and maintain the capability to apply these archaic methods. These things may also be difficult to outsource, except perhaps to specialists. Beware the single expert tradesman – what do you do when they retire? A larger knowledge pool is required to help deal with question like “is this an age-related problem?” and “what do other people with this kit do that works?” [23]

New and advancing technology
Relevant questions regarding new technology are:

- What are the new technology’s impact on safety integrity, as compared to the previous technology?
- Is there sufficient knowledge about the new techonology and its application (otherwise opportunities to improve the safety on the faclity could be missed)?
- Is the facility and nearby equipment suitable for the new technology? Relevant, e.g., for weight restriction for facility and area restriction (access) for nearby equipment.
- Will there be sufficient knowledge availale about the current technology?

To get knowledge about new technology, continuous updating of knowledge about improvement is needed, [28]. There should also be procedures to provide required technical support and sufficient supply of spare parts. There is a need to valuate present status (state) of elderly equipment, and the consequence of combination of old and new equipment on the facility; (e.g. loads, too much equipment resulting in maintenance challenges, boundaries between old and new equipment).

Spare parts
Relevant questions regarding spare parts are:

- Can there be lack of spare parts and/or technical support in the future?
- Can there be lack of suppliers and/or industrial capabilities? [28]
- Will necessary spare parts or critical maintenance support be available? [68]
- Is the need for long lead spare parts evaluated?
- Does the vendor still exist, or do they have the skills to support older equipment? In these circumstances it may be necessary to get advice from a specialist consultant? [23]

- If important spare parts are unavailable, are alternative maintenance and modification plans identified?

Consequences of lack of spare parts etc. are decreasing reliability, and declining performance and safety of facility.

Another issue is ageing of spare parts during storage. If spare parts or consumables could be vulnerable to degradation due to their stocking environment, (e.g. temperature, moisture, chemical attac, dust accumulation), measures should be taken to ensure that they are stored in an appropriately controlled environment, [28].

There is a need for provision of spare parts througout planned LE and timely relacement of parts, long term agreements with suppliers, and development of equivalent structures or components. Availability of spare parts or replacement parts should be continually monitored and controlled, [28].

New operational conditions and needs
Changes in operational and production conditions during an LE period is a major challenge. This is often due to either new operational or production needs, or requirements to increase effectiveness.

Examples are changes in temperature and pressure of produced oil/gas, or converting from oil to gas production. In the latter case, modifications and new well solutions are required. Other needs are for instance possibilities for various operations in an extended weather window, more effective operations or new types of operations due to new requirements (e.g. with respect to spill/emission).

Optimisation, modification and new types of operation can result in various challenges, [68]:

- Old designs are more complicated than newer designs or have not a low-maintenance design.
- Small populations of differing types of equipment cause relative high cost for maintaining knowledge and spare parts.
- Equipment was originally designed for other liquid types, other temperatures and pressure conditions, resulting in a higher risk and lower reliability in the new operation.

Possible operational changes; (other types of operation, new operational requirements, etc.) must be identified and their impact on the risk be assessed.

Overall layout and space challenges on the facility
With new types of operation, modifications and new technology, there can be more equipment installed on the facility, resulting in layout challenges and increased load on the structure. There can be lack of space, more difficult access on the facility and in general increased complexity. Examples are

- Large equipment units such as seawater service pumps and modern BOPs.
- Noise abatement equipment causing decreased accessability.

4.3 Human resources and organisational issues

Human resources
Focus on personnel competency is very necessary. The inspector/operative are the most influential part of the inspection system (the combination of procedure, equipment and personnel) determining how successful (or reliable) the inspection will be in meeting its planned objectives. An ineffective inspection does not provide assurance, [23]. Maintaining a trained and competent work force with an awareness of equipment ageing is an important issue for LE. Loss of corporate knowledge due to retiring staff is another. The following are main questions related to human resources:

- Is there agreement between competence of personnel and equipment, and the use of equipment on the facility?
- Are there ageing challenges related to personnel on facility, e.g. due to retiring staff or generational change?
- Is there sufficient transfer of competence/knowledge (from retiring personnel)? Which competance will/can ”disappear”?
- Maintenance of expertise: Are there sufficient experience, competence and knowledge such that the facility continuously retains at a satisfactory safety level?
- What is the quality of expertise with respect to the future operation, using the available equipment and combination of new and old equipment on the specific facility? What about temporary equipment?
- Do the personnel understand the relevant degradation processes and risk reducing / compensating measures to prevent or reduce degradation?
- Has the accessibility for maintenance to equipment become worse? [23]
- Has the external environment become more hostile (e.g. due to changes in temperature, noise, poorer lightning, more confined space)? [23]

It is also becoming a trend that maintenance is performed by groups that are circulating between different facilities instead of by the workers at the specific facility. This requires more competence for the maintenance group which may not be familiar with the specific facility, its equipment and operation. A positive effect will be that the maintenance is performed by a specialised group with more experience. On the other hand, the knowledge will not be present on the facility continuously and failures cannot be repaired “immediately”. Instead, the facility must wait until the maintenance crew arrives, giving an increased risk in the meantime.

Facility hand-over
The importance of historical data and competence is discussed in [77]. Continuous adjustment of maintenance control is in many companies often comprehended with a *normal* activity and not considered as an additional need during life extension. This may not be the case for smaller companies with limited experience with ageing, limited operational history and lack of competence or in situations where facility history and competence have been lost during hand-over. To close this gap, there is a need for analyse-based preparing to the life extension period.

Hand-over and hand-over documents are also a topic in chapter 6 related to wells.

LE assessment competance
Considerable competence (in various fields) is required to carry out an LE evaluation process. It is essential that this competence is available in the company. Reference [60] also points out that the operator should ensure that experience on LE from other facilities and operating areas should be applied to the analyses and evaluations carried out. The operator should search for best practice on

LE both internally and externally. Dealing with complex ageing issues may require an interdisciplinary approach with participants from operation, maintenance, engineering, equipment qualification, design and research and development, [28].

4.4 Analyses and risk reducing measures

When the above challenges of obsolescence and organisational issues have been identified, we will have an overview of possible deviations (gaps) between

- the required state of the facility, according to current requirements and future operational needs, and
- the anticipated performance of the facility in the LE period.

In particular it is necessary to investigate whether exemptions (regulatory dispensations) that have been granted for the facility can be extended throughout the LE period. Analyses must then be carried out to see how these gaps can be closed; deciding on possible compensating measures (Activity 4 of Section 2.2). Thus, the outcome of this activiy will be a set of suggested compensating measures, together with information on which gap they possible can close and how they should be implemented and followed up.

A gap analysis can be used in an LE process to identify deviations from the requirements. OLF defines gap and gap analysis as follows [60]:

Gap – *an identified difference between systems in place and facilities design and a recognised and accepted standard e.g. the standards in and referred to in the Facilities Regulations.*

Gap Analysis – *a systematic evaluation of the systems in place and the facilities design against the requirements in a recognised and accepted standard e.g. the standards in and referred to in the Facilities Regulations.*

OLF 122 also describes a methodology for performing the gap analysis; dividing the process of performing the gap analysis into five different phases Figure 15:

1. Working meeting and reports
2. Gaps assessment
3. Reporting and follow-up of the gaps
4. Implementation and follow-up of status
5. Closing the gaps

The gaps may be deviations from regulations or can be identified gaps e.g. from the companies separate requirements.

It is recommended that the gaps identified are assessed for criticality in order to ensure the right priority is given to the implementation measures. The main factor for the criticality should be the risk associated with the gap, and it is expected that the gap with the highest risk has the highest priority, [60].

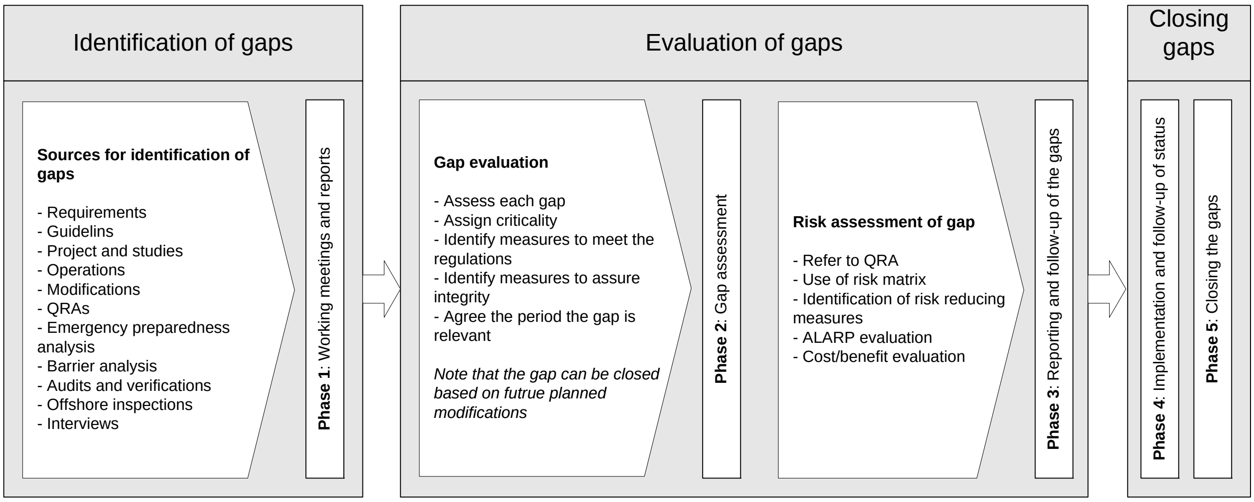


Figure 15: Methodology for performing the gap analysis, based on [60]

The gap can be closed through technical, operational or organisational changes or a combination of these. Risk reducing measures will include

- Technical measures: e.g. replacement or upgrading for equipment, (for obsolescence challenges/new regulations)
- Introduce operational limitations; (equipment is not upgraded for future production/ operational conditions)
- Increased traing/education (challenges related to human resouces)

It can be a challenge to identify a broad spectrum of compensating measures for the various gaps, as the basis for a cost effectiveness analysis. The time needed for the implementation of the measure and the time until full effect of the measures is achieved, are also important parameters. Therefore, it is important to also take the time perspective into account during the evaluation of the compensating measures.

All gaps shall be evaluated, and the ALARP principle (or other principles) be applied in the evaluation; cf. Section 2.7.

The evaluation of the gaps may also indicate that it may not be worthwhile making any changes due to the risk and/or cost of implementations. The following basis can be used to close the identified gaps:

a) Measures have been implemented that ensures the condition meets the facilities regulations and hence eliminates the gap.
b) Technical, operational and/or organisational measures have been implemented that reduce the risk to an acceptable level and meet the principles of an ALARP evaluation.
c) The risk is considered to be low or negligible and no further action is required based on an ALARP evaluation.

An evaluation of the gaps collectively shall be carried out to ensure the combined effect of the gaps is within the risk acceptance criteria. This evaluation shall be done when the remedial measures required to close the gaps have been identified, [60], and is part of the overall risk assessment.

4.5 Examples: Emergency preparedness and other HSE issues

The next chapter discusses the challenges of obscolescence and operational changes with respect to material handling and cranes. Some examples of such issues for the LE process are also found in other chapter (e.g. Section 6.2.2 for wells). Below some tasks related to Safety Systems, (Chapter 9), are given.

The emergency preparedness is critical, as the facility is dependent on a emergency evacuation in case of an accident/major hazard. Possible changes in the emergency preparedness organisations throughout the LE periode must therefore be evaluated as part of the LE process. The emergency preparedness analyses should also be updated if there has been or is planned to be any operational or organisational change that affects the original assumptions and prerequisites.

Escape routes and marking of these
Sufficient marking of escape routes shall be maintained, and it shall be ensured that the escape routes are not blocked, throughout the LE period.

Evacuation with lifeboats
If the facility is equipped with free fall lifeboats and is vulnerable to subsidence, the effect of the lifeboats must be considered. In general, use of lifeboats and their position(s) on the facility must be evaluated with respect to all future expected weather conditions. Also see the next chapter regarding lifting of personnel.

Area emergency preparedness
If the facility is dependent on an area emergency plan in cooperation with other facilities in the area, continuous operation of these facilities throughout the life extension period should be ensured. Otherwise alternative emergency preparedness plans must be evaluated.

Helicopter evacuation/preparedness
Regarding emergency evacuation with helicopters, some important issues to consider are size of helideck, helideck light, competence of helideck crew and radar control.

Other issues to consider
Further HSE issues that can affect risk of major hazards due to obsolescence, are

- *Extreme weather*: Possible climate changes may cause more frequent situations with extreme weather, and extreme weather procedures can be needed. Subsidence of seabed due to reservoir compaction is a consequence of ageing. The subsidence will result in the facility being defined as unmanned in extreme weather.

- *Ship traffic and collision risk*: The surroundings also affect the facility through the possibility of ship collisions. The traffic near the facility may either decrease (e.g. due to fewer nearby facilities) or increase in the LE period. The facility may also be more vulnerable to ship collisions as it ages, e.g. due to subsidence or structure degradation. Hence, the risk analysis for ship collisions should be updated.

4.6 Challenges with respect to obsolescence and operational issues

To an operator, the main challenges of an LE are related to

- Designing a structured approach to identify all obsolescence and operational issues related to the critical functions of the facility, (e.g. through the use of a suitable check list).
- Structuring a gap analysis (or similar) suitable for the LE process, that should be followed up and updated regulary.
- Establishing an approach for evaluating and choosing risk reducing measures; considering cost, time and risk.
- Dealing the combination of new and old equipment and the increasing amount of equipment on the facility leading to layout and possible load challenges.
- Maintaining competence on all equipment during the entire LE period.
- Ensuring availbability of spare parts.
- Collecting sufficient information on the equipment, drawings, historical data, etc., especially after hand-overs.

The SINTEF report [77], based on interviews with several oil and gas companies, summarises the most important consequences for maintenance management with respect to ageing and life extension (related to obsolescence and organisational issues):

- The extent of maintenance increases, resulting e.g. in increased manning
- The maintenance tasks becomes more extensive
- The need to up-date analyses increases
- The need for modifications and replacements increase
- More focus on continuous improvement and maintenance efficiency

5 Material handling and cranes

5.1 Introduction

Material handling is an important issue with respect to obsolescence and organisational issues. An operator that applies for LE of a facility should investigate:

- Operation of existing system for material handling on the facility
- Present status and function of cranes and other material handling equipment (in relation to regulatory requirements)
- Possible future operational/technical demands on the equipment.

This chapter formulates various questions related to these issues. If the operator can not justify that current requirements are met during the entire LE period, and that sufficient flexibility is present to cope with future operational needs, actions must be taken to close the identified gaps. As in other parts of the report, the main focus is on major accidents, which for material handling involves operation in hazardous areas. However, the total function of material handling is considered.

In this report physical degradation is not an issue for material handling and cranes.

5.2 Material handling system and overall requirements

The total system for material handling on the facility must be evaluated with respect to existing and future HSE requirements for lifting and other means of material transportation. The standards [55] (NS-EN 13852-1, Offshore Cranes) and [48] (NORSOK R-002, Lifting Equipment) present general requirements to:

- Perform risk assessment and risk reduction
- Introduce various protections against overload
- Render protection against unintentional and dangerous actions.

This also reflects the required development towards increased safety/reliability. Extended use of *old cranes and lifting equipment* may require a detailed risk analysis, and upgrading may be needed to comply with requirements. If extensive drilling or well intervention is planned during the LE period, the status of cranes and pipe handling equipment should be paid special attention, and facilities without remotely operated pipe handling system installation of such equipment may be advisable, cf. [62].

NORSOK R-002 also presents requirements concerning launching and recovery appliances for life saving equipment (Annex A in the standard) and material handling principles (Annex B). *It should be noted that NORSOK R-002 Lifting Equipment is currently under revision, and that a new version is planned to be published in 2010.*

5.3 Changes of platform layout

Common causes for extending the operational life of a platform are either enhanced recovery at the field or utilisation of the system for treatment of oil/gas from new fields in the area. In both cases new modules are installed, possibly causing concerns with respect to safety, and various questions are relevant:

- Is the visibility and free sight from the crane cabin or for the base man reduced?
- May the path of the lifted objects and thus the crane manoeuvring be more complex from the supply vessel to the platform set-down and storage area?
- Do the new modules or equipment give new hazardous areas influencing boom motion or with respect to consequences for dropped objects?
- Can plans for future changes of layout or operation introduce new hazardous lifting paths, causing challenges related to visibility for the operator or introducing challenges with respect to logistic needs? That is; is there sufficient flexibility to meet future challenges?
- Is there an increased proximity to other objects (causing hazards)?
- Are the landing areas still adequate and suitable with respect to safety?
- Are there sufficient storage areas and material handling routes?
- Are there measures in place to prevent the load from striking objects?
- Is the prevention of accidental overturning (mobile cranes only) sufficient?

In general, lay-down areas shall be designed such that all equipment in the area can be lifted in a safe manner. Areas shall also be dimensioned for the weight and size of the equipment that can be transported in and out for the area. Information regarding the extension and weight capacities of working and lay-down areas shall be available at the operator position for cranes, [48].

The structure of lay-down areas shall be checked for accidental damage limit states due to impacts from dropped objects in accordance with NORSOK N-004. Has the new platform layout increased the risk/consequence of dropped objects in certain areas such that the area must be re-classified (ref. section B.3.3 in [48] for classification of areas)?

5.4 Obsolescence

The main issue when planning an LE, is whether the over-all state of the crane and its ancillary equipment can be considered as acceptable, or if it in general appears to be outdated. Relevant questions are:

- Does the original certification by an enterprise of competence cover the present or expected future use of and needs for the material handling equipment?
- Is the material handling equipment operated under dispensation from current regulations?
- Is the crane type still being produced, and will spare parts be available during the LE period?
- Has the supplier/manufacturer of the crane maintained their competence on that particular crane and its equipment?
- Has the operating company maintained the skill required for safe operation of the crane?

The draft standard [48] has a more detailed set of requirements to maintenance and modifications of possible degradable parts than the previous standard [49]. Even if the crane maintenance program has been in compliance with old standards and regulations, a log should be made available for documentation of compliance with currently valid standards. All maintainers and operators should be aware of the modification, and documentations of modification status should be in place offshore, [21].

5.5 Organisational and human issues

The HSE report, [21] points out the concern regarding changes in operating limits for new cranes. In such situations there must be clear communication and warnings/detailing of the changed operating limits for the crane, particularly for operators who have used the particular lifting equipment earlier, and may have expectations based on previous operating limits. Also, if any particular lifting equipment will be used as part of a not normally manned facility (ref. integrated operations), the risk of an operator attempting to operate the equipment outside its new operating limits is likely to increase due to lack of familiarity and infrequent use.

A contribution to increased frequency of failure (in addition to those caused by material degradation) may be increase in the number of non-critical equipment faults in the wear-out phase. This may have an effect of the operator’s perception of a “tolerable” level of faults and consequently occasional critical faults may be missed.

It is important that the field operator assures competence on wear-out faults.

To meet the above challenges, there is a need of re-education of operators and maintenance personnel to ensure that their awareness of the critical faults is maintained, and that it is known what to expect in terms of wear-out faults, [21].

5.6 Crane load

There will always be incentives to utilise the crane up to and even slightly beyond its capacity. The most common uncertainty is related to peak loads at lift-off from the supply vessel. Inaccurate or optimistic estimation of the sea state may result in too high peak loads, in particular at lift-off from a second vessel. Even for cranes equipped with special lift-off logics the relative velocity can exceed the compensating capacity, also giving too high peak loads.

Another question to consider: If the free sight from the crane cabin is reduced or blocked, the crane's tolerance to radial and tangential load offset may be exceeded.

Further load issues relevant for LE are:

- Has there been an increasing trend in unit weight since the crane was new?
- Will the plans for LE imply increased weight of lifted units or less manoeuvrable units that stretch the functionality limits of the crane, (e.g. increased length or volume of the load, or increased sensitivity to wind)?
- If extensive drilling or well intervention planned during the LE period - will an upgrading be necessary to meet strict requirements to the utilisation and regularity.

5.7 Further HSE issues

In particular the following are relevant HSE issues for operation of lifting equipment during LE:

- Working environment for crane operator
- Safety of personnel being lifted by crane (evacuation)
- Environmental issues.

5.7.1 Working environment

Requirements for health, safety and ergonomics for the crane operator will most likely be an issue for the cabin in old cranes, (visibility, communication, noise, vibration and climate). Section 5.5 of [55] gives rather detailed requirements for the crane cabin (ergonomic design, windows/view), operator seat, instrumentation, communication, noise reduction). Note that these factors could affect the probability of major hazards.

5.7.2 Lifting/evacuation of personnel

The most relevant question is whether the equipment is certified and acceptable for this use (according to current requirements). Old equipment for personnel lifting and evacuation should comply with [48]. Section 5.8 of [55] presents requirements to redundancy in equipment for lifting of personnel.

The consequences of changes of the water depth for the air gap at the muster area and lifeboat station should be considered.

Comprehensive research and development have resulted in a revised standard for free-fall lifeboats. Recent studies indicate that current standards may require updating for conventional lifeboats, (deployed from davits).

5.7.3 Environmental issues

It should be ensured that lifting appliances on movable units (such as drilling platforms) comply with local requirements to environmental impact, e.g. low emission profile and zero spill for operation in Arctic areas.

Weather conditions may change and thus increase the risk related to material handling, e.g. turbulence due to new platform layout. Concepts for lifting and transportation that are weather independent shall always be preferred, [48].

Possible impact that could increase the risk during the LE period should be analysed; in particular, dynamic motions on floating installations and vibrations from other equipment.

5.8 Requirements and safety measures

As stated above, the standards, [55] and [48], present general requirements e.g. to perform risk assessment, carry out safety measures such as motion compensation and heave compensation and introduce various protections against overload. Some further details are given below.

5.8.1 Risk and reliability analyses

Chapter 4 of [55] gives a list of significant hazards and hazardous events that must be considered as part of the risk analysis. Further it is required that a FMEA analysis shall be carried out in accordance with Annex D of [55].

5.8.2 Safety requirements

A few safety requirements are listed below.

- Chapter 5 of [55] lists safety requirements and measures, for the crane system and loads.
- Section 5.6 of [55] gives requirements on controls, a number of indicators and limiting devices
- Section 5.7 of [55] gives requirement on overload and over-moment protection.

Chapter 6 of [55] presents methods to verify conformity with safety requirements and/or measures. In particular there are requirements to perform various types of testing, and test acceptance criteria are provided.

Table 2 of EN 12077-2 contains a list of methods to be used to verify conformity with safety requirements during operation, consisting of inspections, tests and checks. Such inspections/tests/checks may have to be performed more frequently due to ageing and new operations, or there may be need for additional inspections/tests/checks beside those defined during design/previous operation.

5.8.3 Operational limitations/conditions for cranes

Annex C (normative) of [55] presents the operational limitations that apply for cranes. Possible changes in the relevant conditions (e.g. wind, thermal effects) during the LE period could affect the likelihood of complying with these limitations and should therefore be evaluated.

Further, Chapter 7 of [55] gives various requirements on the operation of cranes, (e.g. training, checks prior to operation etc.).

5.8.4 Regulations and standards

The following are considered the most relevant standards for Cranes / lifting equipment:

- NS-EN 13852-1 Cranes – Offshore cranes. Part 1: General purpose offshore cranes. (Section 2 of the standard also gives a long list of normative references)
- NORSOK R-002 Lifting Equipment.
- NORSOK R-003 Safe use of lifting equipment

Annex A of NS-EN 13852-1 ([55]) also gives a selection of a suitable set of crane standards for a given application.

Annex ZA of [55] also informs about the relationship between this European Standard and the Essential Safety requirements of EU Directive 98/37/EC, amended by Directive 98/79/EC.

5.9 Summary of concerns related to material handling

The following is a summary of important issues related to material handling and cranes, which the operator must consider as part of an LE assessment:

- *Installation lay-out and logistics*. Has the lay-out changed? Is there more equipment on board, resulting in sight reduction or restricted lay down areas or material handling routes? Is there sufficient flexibility to meet possible future challenges with respect to logistic needs? Can plans for future layout changes cause challenges related to visibility for operator?
- *Material handling*. Does existing equipment comply with present and future needs and regulations?
- *Crane state*. Can the crane be considered as obsolete? Is there a documented maintenance and modification history of the crane? Is there a possibility of some equipment getting outdated (e.g. lack of spares)? Will competence of relevant personnel be available?
- *Crane load*. Are changes anticipated for the LE period that severely will increase the crane utilisation?

- *Health, Safety and Environment*. Is the equipment acceptable for lifting or evacuation of personnel (according to current requirements)? Are working conditions for the crane operator (noise etc) according to current requirements? Will emissions comply with existing or future (local) requirements. Will environmental changes result in increased wind, more waves or turbulence.

6 Wells

This chapter describes wells and drilling and relevant ageing and life extension issues, mainly with respect to material degradation. Some issues related to obsolescence and organisational issues are also mentioned.

Both subsea wells and platform completed wells are typically planned for a lifetime of 20 – 25 years. However, re-completion of wells typically may take place after 5 – 8 years or more. The conversion of production wells to injection wells and opposite, have created challenges regarding well integrity. Wells can also be modified for artificial lift, like gas lift and down-hole pumping systems. These modifications normally take place by replacing production tubing and part of the casing strings, etc. The main supporting structure of the well, typical the conductor casing and the wellhead casing strings are not normally replaced. Failures, of these elements will not necessarily cause loss of containment. However, they may weaken the well and increase the load effect. Corrosion of the conductor and the surface casing may propagate in to the well barrier elements if not arrested.

The LE process for wells is treated in the following Sections. First, a step by step description of the components of the well system is given. Then the literature review of LE for wells is summarised. Next, comments on the various steps of the LE process are made. In particular, the most relevant degradation mechanisms for each part of the system (barrier element) are highlighted. This information can then be used to see how the generic results of Chapter 2 can be applied.

Well descriptions and information on typical degradation mechanisms and failure modes for typical well materials can also be found on www.exprobase.com [16].

6.1 System description

Offshore field development takes place using both dry wellheads and wet wellheads. Using dry wellheads, the wellhead and X-mas tree are located on a bottom supported platform easy accessible for maintenance and modifications. Wet wellheads with subsea X-mas tree are located on the seabed and not easily accessible. These wells are exposed to sea water, and corrosion is likely to take place. For the latter category, maintenance and modifications normally take place using a floater (Semi-submersible drilling rig, light well intervention or drilling vessel) or a Jack-up platform.

Due to more frequent intervention and lower cost for replacement of well completion components, the knowledge of degradation is generally better in *platform* completed wells compared to *subsea* completed wells. Monitoring for control of degradation in well completion systems is normally not included, even in smart or intelligent well completion systems.

Ther main types of wells are exploration wells, production wells and injection wells. The type of wells considered for ageing and life extension is limited to production wells and water- and gas injection wells. Selecting proper pressure ratings and casing materials in exploration wells allow these wells to be converted to producer or injector at a later stage.

Platform wells were extensively used in the past and were the sole solution for moderate water depths (< 150 – 200 m). Figure 16 illustrates a typical subsea well. Today, the trend is to use subsea completion in new field development, even in shallow waters (< 70 m). In the future, offshore field development will more frequently be based on "subsea to beach" solution where processing of fluids and injection will take place before pumping oil and gas to shore or other facilities for further processing and treatment.

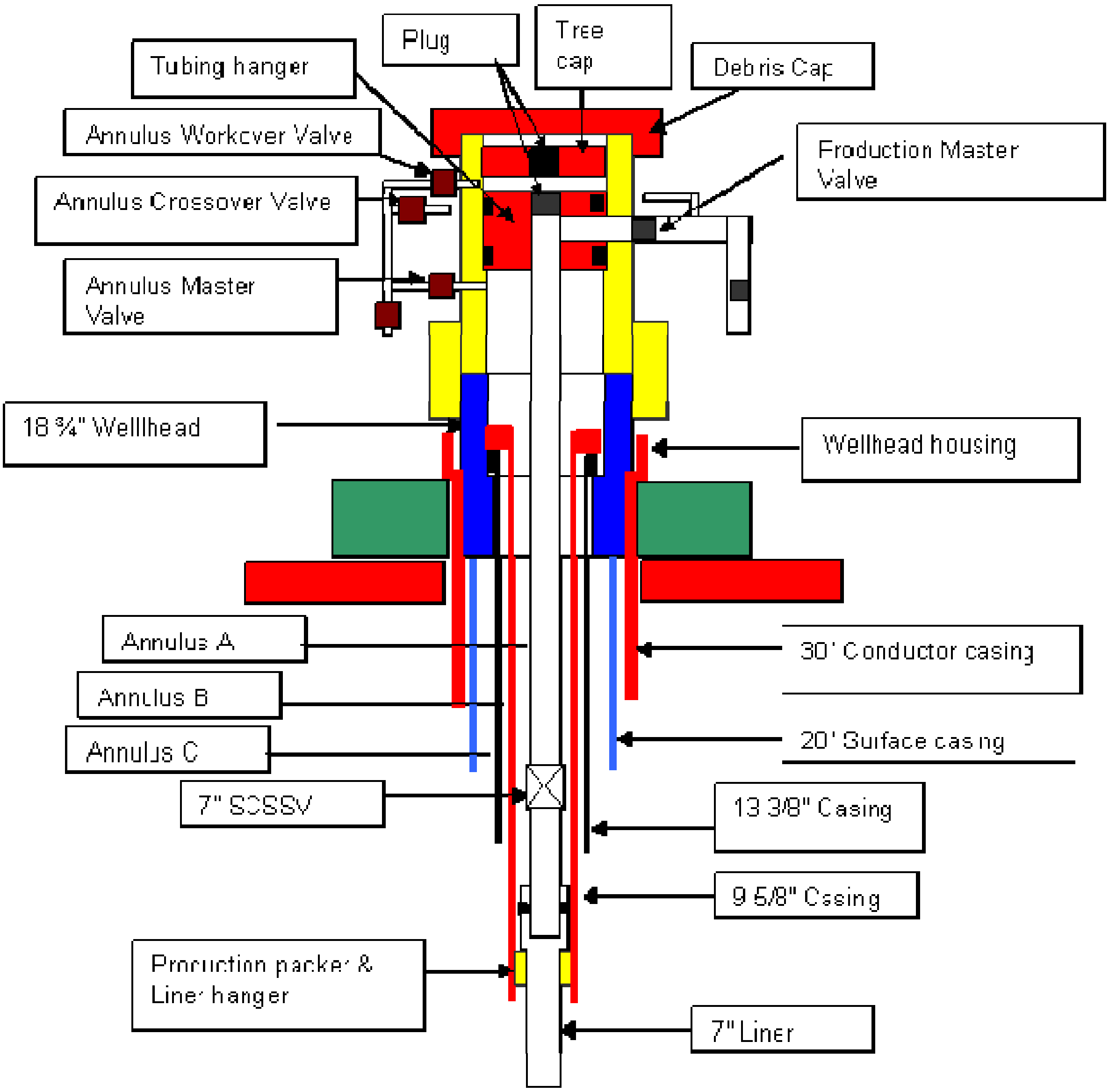


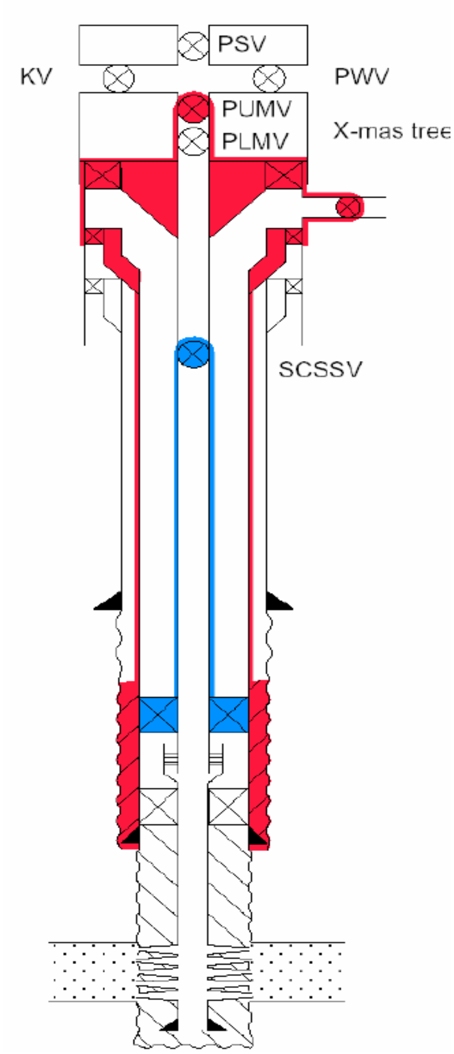
Figure 16: Well completion schematic – Subsea Horizontal X-mas tree

The recovery from platform completed wells is higher compared to subsea completed wells, typical 10 – 15 %. The main reason is the remoteness of the wellhead and the high cost involved with subsea intervention.

6.1.1 Well barrier elements barriers

In principle, the differences in design with regard to safety for different types of wells are minor. Generally, two independent pressure barriers between the reservoir and the surroundings are required. In gas lift wells where the casing / tubing annulus is used for gas injection, an additional pressure barrier (annulus safety valve) is normally used.

In the process of evaluating ageing and life extension of wells, the well barrier and well barrier schematic defined in NORSOK D-010, [46] has been used in an example. Figure 17 illustrates a typical well barrier schematic.



Well barrier elements	Comments
Primary well barrier	
1. Production packer	
2. Completion string	Tubing between SCSSV and production packer.
3. SCSSV	
Secondary well barrier	
1. Casing cement	
2. Casing	
3. Wellhead	Casing hanger, tubing head with connectors.
4. Tubing hanger	
5. Annulus access line and valve	
6. Production tree	Body and master valve.

Figure 17: Example of well barrier schematic, Production (NORSOK D-010, [46])

6.2 Literature review with respect to wells

Generally, review and analysis of historically causes of drilling equipment failures worldwide indicate that mechanical wear, is the most widely reported cause of failure for offshore drilling equipment and wells, followed by corrosion and fatigue damage.

From the reviewed documents concerning offshore industry applications, ref. Appendix C, there are a few documents treating ageing or LE for wells, see Table 11.

Table 11: Reviewed documents on well topics

Documents/reference	Well topics
Articles	
Ageing of materials, [91]	Overview of degradation mechanisms.
Reports	
DnV, *Material risk – Ageing offshore facilities,* [8]	Degradation mechanisms and failure modes
DnV, *Joining methods – Technological summaries,* [11]	Degradation mechanisms and failure modes
SINTEF, *Ensuring well integrity in connection with CO_2 injection,* [83]	Casing testing
SINTEF, *Investigation of 9 5/8'' casing hanger failure,* [80]	Well barrier failure
Standards and guidelines	
OLF, *Life Extension of Facilities. Drilling and Well systems – List of issues that may be addressed,* [59]	Well integrity in life extension. (Checklist)
OLF, *Recommended guidelines for Well integrity,* [61]	Well handover documentation

6.2.1 System specific degradation mechanisms and failure modes

The report, [8], review and analysis of historically causes of drilling equipment failures worldwide, indicates that mechanical wear, is the most widely reported cause of failure for offshore drilling equipment and wells, followed by corrosion and fatigue damage. Other typical degradation mechanisms are erosion and buckling. Typical failure modes are fatigue cracking and reduced wall thickness.

Degradations mechanisms and failure modes for different well systems identified by [8] and [11] are:

Drilling control system
After some years of operations, whole or parts of a drilling **control system** might be upgraded or replaced. The quality control of new control system is often not as extensive as when initially designed, manufactured and tested. Experience has shown that such upgrading sometimes lead to unwanted events. Safety assessments when upgrading control systems should be increased to prevent uncontrolled situations/operations.

Production casing
For wells with a high degree of sand production, erosion will be a relevant degradation mechanism. For wells subject to gas lift, frequent start/stop, water production or varying injection of water/gas, corrosion will be the main degradation mechanism. Geotechnical scenarios like settlements, dislocations, etc., can introduce additional shear and compression loads, and should be taken into account in the design. Detection of damaged production casing is primarily performed by pressure surveillance, and there are a number of quality control and surveillance methods of production casing with respect to thickness measurements.

Wellhead
There are three main contributors to reduce a wellhead (WH) system life with regard to fatigue which is field and vessel dependent: Rough weather condition, lay down weight on WH (BOP, WH casing and subsequent casing weights) and shallow water depth.

The possible damage to subsea WHs are related to drilling or work over mode when the wellheads are subjected to a riser load. The failure mode is related to fatigue, both in welds as well as at stress in base material. The wellheads are normally not accessible for inspection, and hence it is difficult to detect cracks that are in initiation stage. Recent assessments of fatigue lifetime show that the WHs are utilised at a level exceeding already used time with riser exposure. This is particularly important when assessments of old WH systems are done with respect to Increased Oil Recovery (IOR) programmes which may lead to extended riser exposure.

Subsea X-mas tree
The subsea XT is a critical safety barrier build of advanced components. The tree itself is a structure with a number of pressure containing components bolted together with flange type connections generally manufactured from low alloy carbon steel coated by and epoxy based coating. These are sensitive to thermal effects from welding.

The internals of the tree can be exposed to well stimulation chemicals, especially after interventions that can be of aggressive nature. It seems to be situations were the well has been treated with chemicals that can have severe effect to tree internals when not flushed out satisfactory. These chemicals (which can be acid) can remain in dead end pockets, in seal grooves etc., and cause severe local damage.

It is reasonable to believe that non metallic seals in barriers could not be documented at time of design to actual working design life. It is further a discussion in the industry whether the tree is experiencing vibration.

Degradation of coating or insulation can lead to reduced availability in production. High temperature to epoxy coated surfaces can lead to excessive degradation of coating (this shall however be accounted for in the system CP design). For temperature insulation-material care shall be taken to seawater absorption, mechanical wear form impact of external components, and loss of binding between insulation and steel material. The latter can lead to severe local corrosion if the combination is unfavourable with respect to seawater access and lack of CP effect.

Supporting structures of the well
Supporting structures of a platform completed well include the Conductor casing and the surface casing. Typically, the conductor casing is installed 50 – 100 m below the sea bed depending on the soil conditions. Then the hole for the surface casing is drilled and the surface casing is run and cemented. The soil provides axial and lateral support for the casing strings below the seabed, and platform guides provide lateral support for the conductor above the seabed.

In a subsea completed well the conductor casing is typically installed 50 – 80 m below the seabed. Installation methods include jetting, or drilling and cementing.

Whereas failures of these elements will not necessarily cause loss of containment, they weaken the well and increase the load effect on the well barriers. Corrosion of the surface casing may propagate in to the well barrier elements if not arrested.

- **Conductor strength and fatigue**
  In a subsea completed well, the conductor is exposed to axial stress due to temperature changes in the borehole during production operations (well growth). The X-mas tree may be lifted 200 – 300 mm due to temperature increase. In addition to stress in the conductor, significant loads can be transferred through the piping system connecting the X-mas tree and the manifold/flow line if sufficient piping flexibility is not provided. During well

intervention, the conductor is exposed to axial force and bending moment due to riser tension, currents, vessel off-set and Vortex Induced Vibrations (VIV), etc. Significant lateral movements of BOP causes high bending force in the wellhead and conductor casing. This has been observed using ROV with subsea camera. Experiences have shown that subsea wells have been lost due to fatigue and failure of the conductor casing.

- **Surface casing strength**
  Particular the connectors are critical (corrosion). Increasing the wall thickness in the upper part of the casing below the subsea wellhead may improve the fatigue lifetime of the well.

- **Soil axial and lateral support**
  The stress in the conductor depends on the soil conditions, height of cement in the annulus between the formation and the conductor casing, and between the conductor and the surface casing. The soil support is reduced due to lateral movement of the conductor and also by adjacent well drilling. Settlement and soil shearing may cause dog-leg severity. The seabed soil supporting the subsea well may be flushed away causing additional loads in the conductor, surface casing and the supporting subsea structure. Excessive loads, fatigue, erosion and corrosion may cause limitations.

- **Loss off or damage to platform guide shims**
  Additional stress in the conductor and surface casing may take place due to loss of guide shims, etc.

6.2.2 System specific LE assessment

There have not been found any system specific LE assessment procedures for wells, but OLF has issued a checklist of some well integrity “elements”, which should be considered during the assessment of continued safe drilling and well operations, [59]. However, several of the issues on this list are quite general and relates to obsolescence issues, (using wells and drilling as examples), and these are shortly discussed in Appendix B.2. Some of the other topics on this list are listed and commented in the beginning of section 6.3.

Below we list the recommended information for well handover documentation ([61]) and give the activities that shall be included in the well recertification process ([8]).

Well handover documentation, [61], should contain the following well information:

- Wellhead data with schematic
- Xmas tree data with schematic
- Casing program (depths, sizes)
- Casing and tubing data, including test pressures
- Cement data
- Fluid status, tubing and all annuli
- Wellhead pressure testes
- Tree pressure tests
- Completion component tests
- Perforating details
- Equipment details such as identification or serial numbers.

The handover documentation should include the following two well schematics

- Well barrier schematic with well barrier elements listed
- Completion schematic.

The handover documentation should also include a handover certificate which should include actual status on valves, pressure, and fluids at handover.

Operating limitations for the well should also be included in the well handover documentation package. As a minimum the following information should be included:

- Tubing and annulus operating limit
- Test and acceptance criteria for all barrier elements (could be referenced to valid internal company documents)
- Deviations that are identified and valid for the well.

In addition, it is referred to [12], DnV's interpretation of the PSA regulations that a major overhaul/inspection with verification of BOPs and other pressure control equipment used for drilling, completion and workover operations, should be performed every five years. Need to recertify equipment can occur due to e.g. life extension, repair or change of intended use. The following activities shall be included in the recertification process [8]:

- Review of original documentation with special focus on traceability
- Review of maintenance history/records, to verify the amount of use and extent of maintenance
- Stripping/dismantling of equipment
- Visual inspection
- NDT
- Dimensional check of selected components/review of dimensional check reports
- Change out of seals, treads etc.
- Reassembly – recoating – preservation
- Load/pressure testing and functional testing.

6.2.3 Maintenance & ageing related to wells

Literature findings related to maintenance and ageing for main well components are given below.

Casing integrity tests [80]
Corrosion and cement bond logs are amongst the most common techniques use to evaluate casing mechanical damage. The simplest method to measure down hole corrosion and erosion is through the use of multi-finger callipers. Electromagnetic thickness measurement tools could also be used to measure down hole corrosion/erosion and to estimate the wall thickness. Also down hole video cameras are useful to imaging down hole corrosion.

Subsea X-mas tree [8]
Regardless of vibration or its frequency, it is important that slim members, such as small bore piping are supported sufficiently such that long term effect of vibration does not lead to breakage.

High strength material shall be selected with sufficient margin to avoid HISC, and the operation stress level shall be below certain values.

Override mechanisms and override stems that extend from actuator housing to external seawater atmosphere can be a possible degradation to functionality. E.g. marine growth, calcareous deposits can lead to failure of the sealing element between actuators and seawater allowing seawater into areas not tolerant to this. Also severe friction can, due to mentioned effects, lead to challenges in operating e.g. valves or other mechanisms.

Inspection of XT shall cover following checks:

- The CP system – looking for excessive consumption of anode mass
- Recording of anode potential and steel if practically
- Coating damages, both due to general degradation and as effect of hot surfaces
- General damage to structure from fishing gear
- General condition to pipe coating
- Inspect for leakages at valves, connectors, sensors and components
- Pressure test
- Visual inspection to detect foreign objects.

Supporting structures

Below are some well considerations with respect to fatigue, foundation and settlement, structural degradation/capacity and variations from design and construction.

Considerations with respect to *fatigue*:

- Consider conductor and surface casing welds and connectors as well as wellheads
- For subsea wells, consider the effect of high current – VIV and wave period
- Actual duration and actual weather / season and connection to the riser to be compared with well design assumptions
- As-build wells to be compared with design to check for any stress raises which may have been missed – (welded systems, welded attachment, etc.)
- Uncertainty in fatigue durability of older connector types to be considered – reliability of components.

Considerations with respect to *foundation and settlement*:

- Check for evidence of excessive well growth/settlement in service or during construction
- Check for cratering around subsea wells or other evidence of excessive lateral movement with riser connected (bull`s eye readings, ROV reports)
- Check for cement shortfall
- Shearing of casings.

Considerations with respect to *structural degradation/ capacity*:

- Check for excessive tree movement for platform wells, loss of centralisation
- Conductor connector fatigue and strength failure
- Check if life extension increase loading, e.g. change of use from production to water injection
- Degradation of conductors through sea water leakage
- Impact damage to conductors and conductor guides
- Corrosion.

Considerations with respect to *variations from design and construction*:

- Any changes from design and as- build casing program and reason for change
- Challenges encountered during drilling e.g. which may lead to excessive wear
- Change in drilling rig – more heavier and/or taller BOP, higher riser and drill string loads – could lead to overload and increased fatigue damage
- Improved knowledge of environment and foundation condition could highlight insufficient design loads.

6.3 Life Extension assessment – wells and drilling

This section provides some further comments and evaluations relevant for the LE assessment of wells.

6.3.1 Requirements and issues for the LE assessment

Some comments are given below on the well specific challenges derived from the OLF checklist, [59] **:**

- *Relevant incidents and well integrity KPI records expected to be followed up.* This is also a general consideration; (e.g. see section 3.1.4 on data needs and section 2.8.1 on indicators). However, it points out that *well integrity* is a factor of specific importance.

- *Well integrity situation and possible changes in the related risk-picture (locally and towards other parts of the facility).* Some of the major hazards are related to loss of well integrity, and need particular attention in the risk analyses.

- *Potential well stimulation, intervention & work-over methods/limits*: Well stimulation may introduce unacceptable stress level in casing - and production string, etc., due to change of temperature and pressure. Well intervention, workover and side-track drilling operations including Through Tubing Rotary Drilling (TTRD), may increase wear. In subsea completed wells, vessel movement, loads on BOP and riser from sea water current, etc., may cause unacceptable stress level and fatigue. Ref. also Section 6.4 on lack of knowledge due to wellhead fatigue from e.g. well intervention.

- *Future capabilities to serve for potential "tie-ins" and specific measures for enhanced petroleum recovery in the area:* The potential for tie-ins must be evaluated, for both subsea and platform wells. New tie-ins may lead to increased pressure which will impact the interfacing pipelines such that installation of HIPPS valves must be considered. New tie-ins may also give different CO_2 and H_2S contents, require (additional) chemical injection or result in a completely different pressure. If number of platform wells is increased, it is important to consider whether the separator capacity is sufficient; (also water content of fluid will increase). Other tie-ins issues are old equipment, weight challenges and lack of space. New tie-ins require new and modern equipment resulting in more equipment on deck restraining maintenance and increasing the probabilities of cracks, collapse. It is therefore recommended to perform a thorough analyse with respect to the required equipment to ensure a sufficient safety level. Required equipment or modification that become too heavy and/or too place consuming with respect to maintenance challenges and increased risk, respectively, limit the possibility for tie-ins. (In fact, when considering life extension in general on one facility, the impact on/from other facilities in the extended life period must be evaluated. How will changes in production on the facility/nearby facilities impact the nearby facilities / facility under consideration? Increased pressure and changes in production fluid could influence on the safety integrity of pipelines, subsea systems and process systems.)

- *Verification/analysis of load-bearing structures for such as derrick w/sub-structure, handling arrangements and well head strength:* Well head fatigue due to variation of loads is an area with limited knowledge, ref. Section 6.4.

- *Condition of support arrangements for well/wellhead/conductors, (impact by wear, motion, subsidence):* Well head load and fatigue due to variable loads from moving vessel, etc. is an area with limited knowledge, ref. Section 6.4.

- *Plans for testing integrity of wells/well barriers, for extended use:* Modified maintenance, such as increased testing frequency are important risk reducing measures in the extended life (Section 3.2).

- *Systematic checking for leakage and monitoring annulus pressures:* (Possibly increased) monitoring is a general risk reducing measure, which certainly applies to annulus pressures.

- *Impact/degradation inside and outside of the well/ barrier envelopes (by H_2S, CO_2, other chemical, erosion, corrosion, deformation, fatigue, wear, etc.)*: Degradation mechanisms and operational conditions are discussed in Section 3.1.

- *Well control facilities and well killing capabilities:* For instance consider risk related to “bull-heading” where high flow rate and pressure may be required to perform well-killing.

- *Technical premises for potentially converting wells (e.g. from production to injection)*: For production wells small leakages may have occurred for a long period, and if it is converted to injection well, the pressure will often increase, also giving a higher risk that must be evaluated. (See e.g. section 3.1.3 on process parameters and operational conditions).

- *Possible impact on interfacing facilities/outfitting (e.g. flowlines):* Interface with other systems must be addressed; to see whether changing operating conditions or the facilities’ state of degradation can affect other systems.

- *Strategy relating to Plug and Abandon (P&A):* Executing P&A is to be carefully considered, especially for subsea templates since normally none of the wells on the template can be plugged without shutting down production on the template. For single subsea wells, with a lot of pipelines and control lines on the seabed, anchor handling is critical and requires thorough planning. Additional stress on casing and tubing strings due to subsidence and/or increased corrosion may result in leakages if P&A is delayed. A general question for all types of wells is: How long is it worth waiting until P&A is executed without threatening the well integrity?

- *Well integrity competence/recourses:* Need of competence/resources is essential, ref. Chapter 4. Also see Section 6.4 (“Lack of knowledge”).

Note that the above considerations are drilling and well specific. Various general issues are discussed in Chapter 2, Chapter 4 and Appendix B.

Well integrity issues
PSA Norway has performed a well integrity survey based on a selection of in total 400 production and injection wells, presented in [30] and [70]. The study of the survey results revealed that the industry needs to increase focus on barrier philosophy and control of barrier status. They also identified insufficient transfer of critical information during licence acquisitions, change of operater and difficulties for key personnel to get access to essential well-data when well control

situations occurred. There is a general need for improved hand-over documents for operations, which was described in the previous section.

The most frequent well intergrity problems and barrier element failures are, [30]:

- Tubing problems; leakage in production tubing above DHSV, tubing to annulus leakage or internal leakage in tubing hanger necks seal
- Annulus safety valve (ASV) problems; leakage or failure of ASV
- Casing problems; casing leakage (non-gastight connections) or collapsed casing
- Cement problems; no cement behind casing and above production packer, leaks along cement bonds or leak through cement micro annulus
- Wellhead problems; leakage in wellhead from annulus A to B because of wrong seal type in the wellhead.

6.3.2 Required information on design, materials and operation

Reference is made to NORSOK M-001Material selection, rev. 4, August 2004. For well equipment installed before NORSOK was introduced early 1990`s other materials may have been used.

Table 12: Important input information for the well completion system

TYPE OF INFORMATION					
DESIGN & INSTALLATION		OPERATION		LIFE EXTENSION PERIOD	
No.	Description	No.	Description	No.	Description
1	Material(s), protection, insulation	8	As-installed/built documentation	16	New tools/design methods/ experience since design
2	Design life calculations	10	Info. about maintenance and modification	20	Info. about maintenance (planned repair) and planned modifications
3	Drawings	11	Process/operation parameters	21	Process-/operation parameters (changes from design)
4	Valid standards and RP	12	Info. from condition monitoring	22	Changes in classification due to change in operation parameters
5	Operation and process info.	13	Info. from inspection/testing	23	Length of Life Extension period
6	Installation loads	14	Info. from similar operation		
7	Installation accidents	15	New standards and RP		

Table 13: Important information (process and operation) and actual condition monitoring sources

SYSTEM NAME	PROCESS PARAMETERS	OPERATION PARAMETERS	CONDITION MONITORING
Production tubing and tubing accessories X- mas tree	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity	Solid particles Corrosion inhibitor Chemical addition Loads and vibration	Pressure Wall thickness Vibration Inspection
Production casing (Annulus - A)	Completion fluid composition	Corrosion inhibitor Loads and vibration	Pressure Wall thickness Inspection[1)]
Casing (Annulus - B)	Drilling fluid composition	Solid particles Loads	Pressure[2)] Wall thickness
Casing (Annulus - C)	Drilling fluid composition	Solid particles Loads	Pressure[2)]

SYSTEM NAME	PROCESS PARAMETERS	OPERATION PARAMETERS	CONDITION MONITORING
Wellhead, conductor and surface casing	Temperature	Loads due to temperature and pressure changes Loads during drilling and well intervention[3)]	Stress, strain, frequency[3)]

1) After tubing retrieval,
2) Normally not valid for subsea wells
3) Valid for subsea wells

6.3.3 Evaluation of ageing mechanisms and failure modes

Table 14 shows the most relevant degradation mechanisms for the well completion system.

Table 14: Summary of most relevant degradation mechanisms for a well completion system

SYSTEM NAME	MOST ACTUAL DEGRADATION MECHANISM[1,2)]
Production tubing and tubing accessories	A, B5, B6, D1, E1, F3, G, H, K, L, M
X- mas tree	A, B5, B6, D1, E1, F3, G, H, I, K, L
Production casing (Annulus - A)	B5, B6, E1, G, H, K, L
Casing (Annulus - B)	B5, B6, E1, G, H, K, L
Casing (Annulus - C)	B5, B6, E1, G, H, K, L
Wellhead, conductor and surface casing	B5, B6, E1, G, H, I, L

1) See List in Section 3.1
2) Depending on actual material used

Horizontal X-mas trees

Using horizontal X- mas trees, significant stress and fatigue may take place in the connection between the wellhead and the tree due to loads imposed by the drill string, riser and BOP during well intervention and drilling operations.

Components are typically bolted to the tree bloch with flange type connections generally manufactured from low alloy carbon steel. Significant problems have been experienced using high alloy bolts not suitable for the subsea environments (HISC).

6.3.4 Maintenance and modification for wells

There are various maintenance methods for wells:

Upgrade

Repair and/or replacement of components or the complete casing and/or production string with accessories are a possible outcome for the well completion system.

Monitoring

Monitoring process and operation parameters is important for the process system. The most important parameters to monitor are:

- Pressure
- Temperature
- Content of solids (sand)
- Fluid composition (inclusive water content)

Other actual methods can be:

- Acoustic techniques for measurements of leakage and vibrations,
- Devices for measurements of load, e.g. stress, strain and fatigue.
- Erosion monitoring in outlet piping on the X-mas tree.

Inspection
Different methods can be used to inspect the well completion system. Video camera, calliper and ultrasonic inspection methods, etc., run on cable are used for down hole surveys. Subsea X-mas trees can be inspected with different methods by using ROV. Subsea wellheads are at present not accessible for inspection. The industry has an ongoing project within this field.

Well growth due to changes in temperature and pressure is easily observed on platform completed wells.

Maintenance
The output from the LE analysis can also be an update of the maintenance program.

Testing
Pressure testing is often used to verify repair of well completion system and to verify that the component fulfils the defined pressure requirement. Testing is also used to control the functionality of valves (e.g. safety valves). Ref. API Spec 6A.

New technology
New technology should according to PSA's facility regulations §8, criteria shall be prepared with regard to development, testing and use in order to fulfil the requirements. In order to fulfil the requirement the regulation refers to DNV RP-A203 Qualification Procedures for New Technology may be used. Examples of new types of well equipment that may be certified are Gas Lift Valves (GLV), Chemical Injection Valves (CIV), new types of cement and possible substitutes to cement. Another example is new equipment and methods to reduce loads and fatigue of subsea wellhead and X-mas trees.

6.4 Challenges and lack of knowledge

The following possible challenges/concerns should be addressed to increase the state of knowledge for the well completion system:

- Lack of knowledge of material properties (including degradation mechanism)
- Methods for down hole inspection and monitoring of material behaviour. (The cement level between the surface casing and conductor casing may be of particular interest regarding stress and fatigue lifetime of subsea wellheads).
- Lack of knowledge of fatigue and fatigue models. Especially fatigue of subsea wellheads and X-mas trees due to weight and movement from BOP, riser and rig from well intervention and from side track drilling. How long is it reasonable to operate with respect to fatigue impact on the wellhead?
- Lack of knowledge of lecage frequencies, especially for X-mas trees.
- Lack of knowledge of wear and wear models. Especially wear in the production tubing and wellhead due to rotating of drill string during Through Tubing Rotary Drilling (TTRD) (platform wells and subsea wells) and wear on risers (subsea wells) due to rotating drill string in combination with loads.
- Lack of knowledge of loads during drilling, production and work over. The critical sections below the wellhead are not accessible neither for inspection nor instrumentation.

One method may be to locate proper sensors on the X-mas tree and/or the BOP to obtain load and deflection date during drilling and well intervention. These data can then be used to estimate the loads in the critical area of the conductor and the surface casing below the wellhead. Online monitoring may also allow minimizing the loads by proper operation of the vessel.

- Lack of knowledge of new equipment and methods, or alternative operaional procedures to reduce loads and fatigue of subsea wellhead and X-mas trees.
- Lack of knowledge about geological effects from subsidence, such as “slippage” between layers (faults)
- Lack of knowledge of fatigue of wellhead (suface casing and conductor casing) including horizontal X-mas tree (subsea)
    - Actual loads and boundary conditions
    - Load frequency
    - Soil condition impact
    - Remaining fatigue life estimation
- Lack of knowledge of sand production
    - Modelling of erosion caused by sand particles
- Challenges related to hand-over documentation and and transfer of critical information / essential well-data during licence acquisitions, change of operater and difficulties for key personnel.

7 Pipelines, risers and subsea production systems

Pipelines and subsea systems are typically planned for a lifetime in the order of 20 - 25 years. Replacement of riser typically takes place after a shorter period of time depending on type of application, service, etc.

The LE process for these systems is treated in the following Sections. First, a step by step description of the components of the system is given. Then the literature review of LE for pipelines, risers and subsea production systems is summarised. Next, comments on the various steps of the LE process are made. In particular, the most relevant degradation mechanisms for each part of the system is pointed out, i.e. sub-systems (considered as barrier element), and see how the generic results of Chapter 2 can be applied.

7.1 Subsea system overview

Figure 18 gives an overview of a subsea production system including a FPSO and an off-loading tanker.

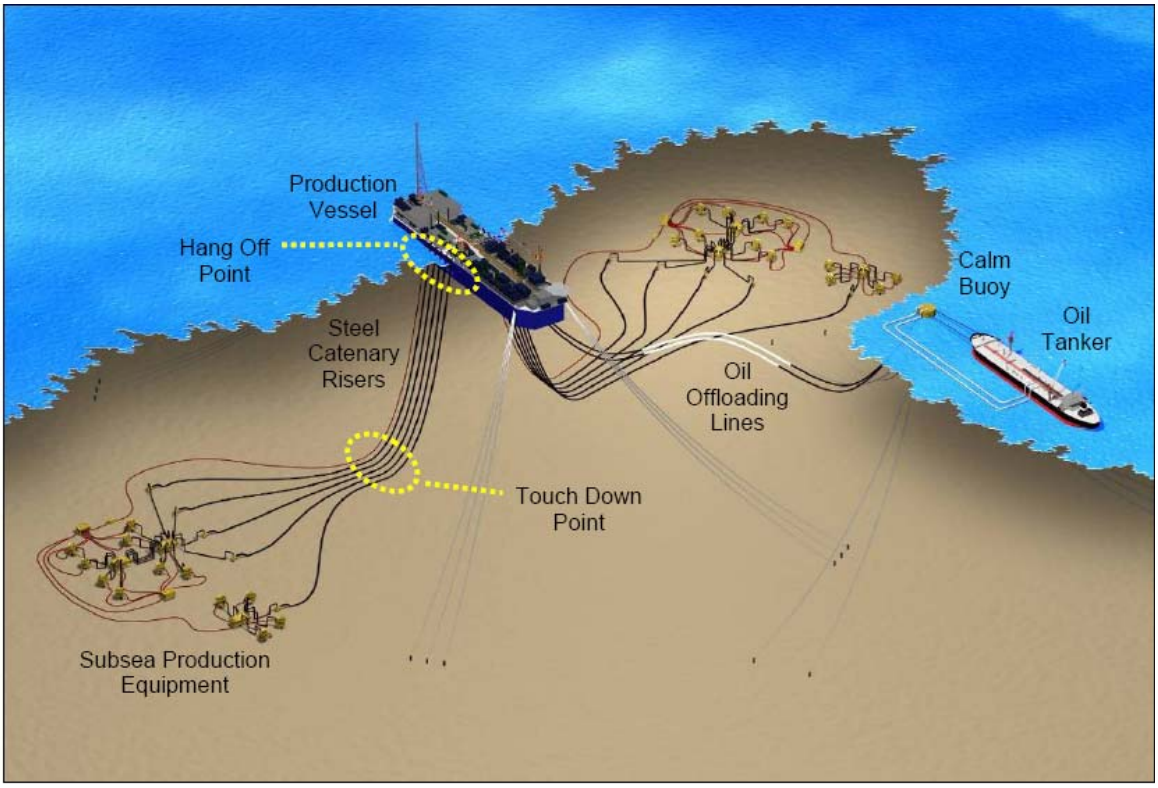


Figure 18: Subsea production systems - an overview

7.1.1 Pipelines

Subsea pipelines – including transport pipelines (processed/partly processes well fluid) and flowlines (multiphase flow) - typically consist of a steel pipe with an external corrosion protective coating, e.g. epoxy. In some cases the pipe is insulated by a polymer coating on top of the epoxy layer to reduce heat loss. Transport pipelines with diameter exceeding typically 20” have a cement based coating on top of the corrosion coating the purpose of which is to give negative buoyancy and provide protection against mechanical damage caused by e.g. dropped objects, anchors or trawl boards. The pipelines are typically made from 12 m pipe sections that are joined by girth welds.

Attachments, normally shaped as oval pads are welded to the pipe to provide electrical connection points for cathodic protection (CP) systems, or for direct electrical heating (DEH) systems. Hydrate and wax formation in subsea flowlines will cause undesired fluid properties and even blocking of the wellstream, which implies shutdown and comprehensive reparations. Direct electrical heating (DEH) is developed as a method for removing hydrates and wax, and is also applicable for solving plug situations. At the pipeline terminations various types of equipment such as monitoring equipment, valves, slug catchers, pig launchers and pig receivers are installed.

The material used in pipelines is normally a carbon-manganese (C-Mn) steel in grades X60 or X65, the number indicating the specified minimum yield (SMYS) strength in ksi. Pipelines carrying aggressive constituents such as hydrogen sulphide (H_2S) or CO_2 are sometimes made from stainless steel alloys, e.g. 13Cr supermartensitic stainless steel (S13Cr).

7.1.2 Risers

Production risers are typically grouped as follows:

1. Flexible risers
   - Bonded
   - Un-bonded.

2. Metallic risers
   - Top tensioned risers
   - Steel catenary risers (SCRs).

The major part of flexible risers in operation in Norwegian offshore sector, are un-bonded pipes [75].

Approximately 85 % of risers for floating systems world wide are flexible risers. Of the 15% metallic risers around 75% are top tensioned risers. Currently only a small fraction of risers are SCRs, however SCRs are a very attractive option for deep water field developments. Hence a large research effort is dedicated to develop fatigue and corrosion resistant SCRs.

Flexible risers are used for a range of functions: Production risers for gas and oil, water injection, gas lift, gas injection, oil or gas export, test productions etc. Flexible risers are also used for drilling and well maintenance. In this report the discussion is limited to the transport function [82].

Flexible risers used for production, injection or export are likely to be subjected to a number of conditions that may be affect the integrity of the riser. Due to the rather complicated wall structure where materials with very different properties are interacting, a large number of failure modes are possible. Many of these failure modes are related to material properties. In this section the different layers of a flexible riser are described with respect to function, structure, material and possible failure modes [82].

<u>Barriers:</u>
Typical cross section of flexible pipe wall structure (see Figure 19 and Figure 20):

1. Stainless steel carcass

2. Thermoplastic liner
3. Carbon steel pressure armor
4. Carbon steel tensile armor, two contra-wound layers
5. Thermoplastic outer sheath

Figure 19: Typical cross section of flexible pipe wall structure [82]

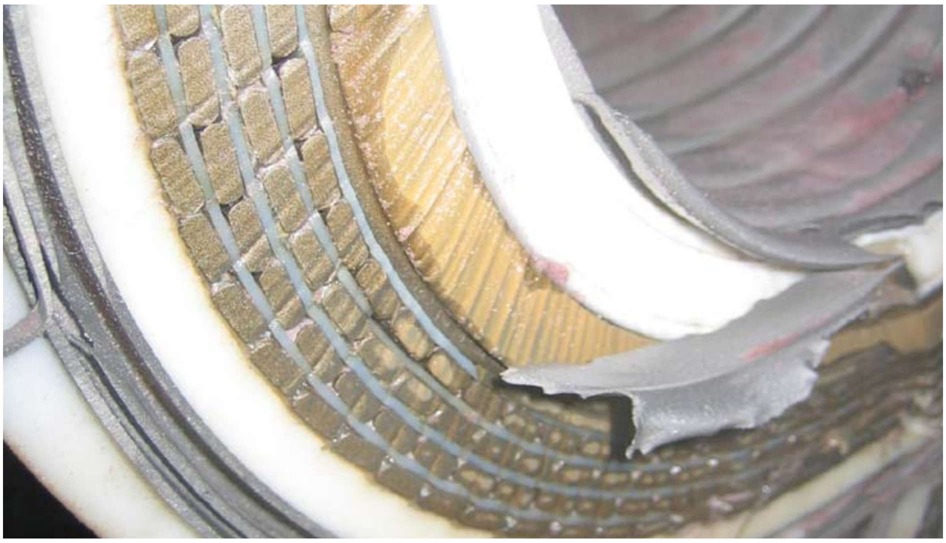


Figure 20: Un-bonded flexible riser with external fire protection layers and 4 tensile armour layers [75]

7.1.3 Subsea production systems

Subsea production and injection systems are based on using satellite wells and template wells. Using satellite wells, each well has a dedicated control umbilical and flow line.
Using a template consisting of several wells allows for cheering common functions, like flow line, control umbilical, etc. A manifold collecting flow from each well is typically located on the template. In many subsea field developments, both satellite wells and template wells are used.

The main elements of a subsea production system may include:
- Subsea wellhead and X-mas tree

- Manifold piping, valves and connection
- Control and monitoring systems
- Control umbilical
- Subsea power and frequency converters
- Subsea separation and boosting systems
- Template with protection structure.

In addition, it normally includes flowline, pipeline and riser systems as discussed in Section 7.1.1 and 7.1.2. The subsea wellhead and X-mas tree have been included in Chapter 6 and will not be further discussed here.

7.2 Literature review with respect to pipelines

From the reviewed documents concerning offshore industry applications, ref. Tables in Appendix C, there are a few documents treating pipelines in connection to ageing or life extension:

Table 15: System/context relevant documents reviewed

Documents/reference	Pipeline topics
Articles	
Ageing of materials, [91]	Degradation mechanisms
Managing life extension in ageing offshore Installations, [85]	Ageing and damage related degradation, external and internal
Reports	
DnV, *Joining methods – Technological summaries*, [10]	Deepwater pipeline hyperbaric repair welding (page 29)
DnV, *Material risk – Ageing offshore facilities*, [8]	Degradation mechanisms, failure modes and maintenance
SINTEF, *Material selection of weldable super martensitic stainless steels for linepipe material*, [82]	Degradation mechanisms
Standards and guidelines	
ISO, *Pipeline Life Extension*, [44]	Mainly LE assessment

In addition, [65] presents the findings of an update to the Offshore North Sea Pipeline and Riser Loss of Containment (PARLOC) database to the end of 2000. The database has been used to perform risk assessments of factors affecting the frequency of incidents. Examples of contents of relevance in [65] are factors influencing leakages (e.g. pipeline age), corrosion and material defect incidents, corrosion protection and pipeline routing and protection. The PARLOC database and [65] have not been given any further attention in this report.

As pipelines become older, new challenges must be considered [7]:

- Changes in integrity, e.g. time dependent degradation mechanisms such as corrosion and fatigue, or random mechanical damages (e.g. third party damages)
- Changes in infrastructure form the as built, e.g. increased fishing activity or heavier trawler gear
- Changes in flow contents, increased amount of H_2S increase the risk of sulphide stress cracking.
- Delamination coating
- Changes in operational conditions, either as a natural change in well-stream condition, tie-in to other pipeline system or increase production rates.
- Required to operate beyond the design lifetime (General for all systems)

- Design no longer valid due to the above mentioned issues (General for all systems).

[85] mentions in addition:
- Difficulty and expense of inspection and intervention

7.2.1 Standards

The following standards are considered the most relevant for pipelines:
- NORSOK Y-001 Subsea pipelines
- Offshore Standard DNV-OS-F101, Submarine Pipeline Systems, October 2007.

7.2.2 System specific degradation mechanisms and failure modes

- Some examples of ageing and damage related degradation of pipelines are [85]:
- Loss of coating (weight coating and paint)
- Impact damage (e.g. dropped objects, scaffolding poles)
- Damage form dragged anchors
- Damage from trawling equipment
- Loss of support and free span development
- Overload
- Vortex induced vibration (leading to increased fatigue)
- Sand bank movements (as experienced within the southern North Sea).

As the pipeline is operated, some internal upsets can cause “internal” damage which accumulates to cause further effects of ageing and which contributes to accelerating other ageing mechanisms, [85]:
- Product changes during service life
- Sweet corrosion (CO_2 and H_2O)
- Sour corrosion (H_2S)
- Incorrect chemical dosing
- Flange gaskets being wrong tightened (over-tightened or in wrong sequence)
- Flow induced fatigue
- Slugging loads (mainly in-field flow lines)
- Pipeline/pipe work pressure testing
- Buckling
- Enhanced temperatures form produced fluids.

Generally, review and analysis of historically causes of pipeline failures worldwide indicate that corrosion, specifically internal corrosion, is the most widely reported cause of failure for offshore pipelines, followed by maritime activities (e.g. anchor- or trawling- damage and vessel collisions) and natural forces (e.g. storms and mudslides). Other typical threats are erosion, development of free spans (causing fatigue) and buckling, [8].

Corrosion degradation mechanisms that have had special focus and may limit the use of C-Mn steel or S13Cr steel as pipeline material are, [81]:
- General corrosion at low pH’s
- Sulphide stress corrosion (SSC)
- Stress corrosion cracking (SCC) or hydrogen induced stress cracking (HISC) and its impact on fracture mechanics behaviour.

Inn addition, [8] mentions microbiologically induced corrosion on carbon steel as another possible internal degradation mechanism.

Control of degradation mechanisms [8]:

- External corrosion; Corrosion protection often consists of a tight protective layer around the pipeline exterior combined with sacrificial anodes. The external protective coating is often asphalt enamel or fusion bonded epoxy (FBE) covered with other types of plastics for mechanical protection or as heat insulation.
- Concrete weight coating; Concrete is applied to the coated pipeline to provide the required compaction and density. The thickness of the concrete ensures both mechanical protection and density for negative buoyancy.

Ch. 4.6 in [8] lists up the external corrosion protection means and corresponding inspection methods/corrosion monitoring for different corrosion zones.

The main failure modes for pipelines are normally considered to be [6]:

- Leakage; often associated with the presence of local corrosion attacks (e.g. local CO_2-corrosin, pitting) or as a result of small cracks.
- Burst; associated with a uniform wall thickness reduction or more extensive crack propagation, decreasing the pressure capacity of the pipeline.
- Local buckling/collapse; often related to external overpressure in combination with a wall thickness reduction (e.g. as a result of corrosion)

Coating damage, [91]

All subsea systems shall principally be provided with its own cathodic protection system. Interaction in terms of current drain between the pipeline cathodic protection system and adjacent subsea facilities electrically connected may cause excessive anode consumption of one of the structures. As the utmost consequence a reduced design life of the cathodic protection system and thereby an insufficient protection of the pipeline system may occur.

Hydrogen embrittlement, [81]

The common denominator of failures of (S13Cr) pipelines (girth welded approximately every 12m) on the Norwegian continental shelf is hydrogen embrittlement or hydrogen induced stress cracking. [81] describes shortly the failure investigations from eight pipeline failures in the period 1998-2003.

Hydrogen embrittlement is normally associated with cathodic protection in conjunction with welds, more specific heat affected zones. The weld toe, or similar surface offsets, will act like a stress concentration area and the microstructure of the heat affected zone is likely more sensitive. In addition, the residual stress from welding adds on the local stress level. Cracking usually initiates at the fusion line or close to the fusion line in the heat affected zone. Cracking of failures have been documented to be caused either by

- hydrogen from the welding wire or moisture in the shielding gas or condensation on the pipe/groove surface
- hydrogen uptake and diffusion form cathodic protection.

Two major degradation mechanisms with respect to corrosion and corrosion protection of S13Cr stainless steels (resulted in significant research and development) are:

- High Temperature intergranular corrosion caused by sensitising (Cr-carbide precipitation) of the heat affected zone by multipass welding
- Hydrogen induces stress cracking caused by high local levels of hydrogen (impact from CP)

7.2.3 System specific LE assessment

The ISO recommended practice [44] gives guidance that should be followed in order to evaluate life extension of rigid metallic pipelines. Figure 21 below shows the flowchart of the life extension process (step 1-6).

The process starts with a trigger to the pipeline extension process at time now (step 1). The initial evaluation will be looking at historical data to determine the status of the pipeline as is (step 2 and 3). Step 4 will fully define the life extension needs prior to the risk assessment being carried out under step 5. On acceptance of the risk the life extension process is fully documented and implementation set up as shown in step 6.

The assessment should be limited to critical elements of the system.

Short life extensions (in the region of 1 to 3 years) would typically undergo an initial qualitative assessment which could satisfy the required life extension period. If not, further quantitative assessment would be required (steps 1 to 6). Longer life extensions would typically undergo both qualitative and quantitative assessments.

Similar process description can be applied on life extension assessments of other systems as well.

[75] gives a brief life extension assessment for flexible risers by listing key pieces of information needed to be considered: “In order to determine whether life extension is feasible, analysis of the flexible pipe history is required. This generally includes the assessment of fatigue (in which annulus condition is of paramount importance), polymer ageing (based upon coupon samples, operating pressures and temperatures and chemical injection data) and anomalies identified from GVI. If sufficient data is not available from the flexible pipe history then, it may not be possible to determine the suitability for LE without significant intervention including possible retrieval and testing.”

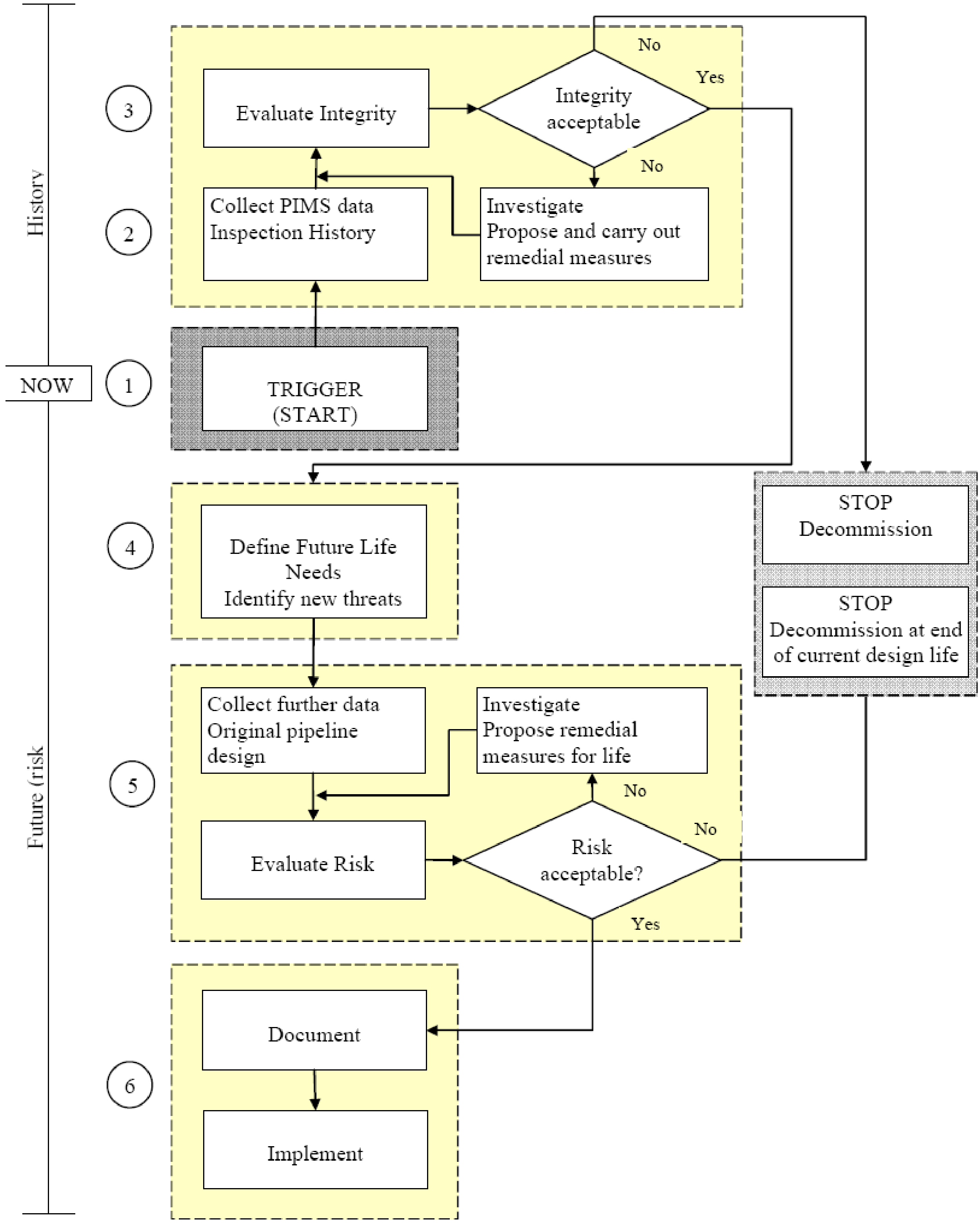


Figure 21: Flowchart detailing pipeline life extension process [44]

7.2.4 Maintenance & ageing related to subsea pipelines

To be able to perform an integrity assessment of a pipeline system, the data and results from the activities illustrated in Figure 22 has to be made available.

One of the challenges with older pipeline system is that historical data and also often original design, fabrication and installation data and reports are lacking. This complicates the possibility of performing a reliable integrity assessment.

Ensuring integrity of subsea pipelines
The following main activities are described in [8] :

- Process and product control; shall ensure that the conditions are within the operational window and includes
  - Process control (pressure, temperature, flow rate etc)
  - Product sampling (CO_2, H_2S, sand etc.)
  - Chemical injection for corrosion prevention
- Corrosion monitoring
  - Corrosion coupons / ER-probes / LPR probes
  - Sampling
- External inspection
  - Visual inspection performed by divers
  - Inspection performed by using Remote Operated Vehicles (ROV)
  - External Ultrasonic Testing and Thickness Measurement for verification of metal loss or cracks
- Internal inspection

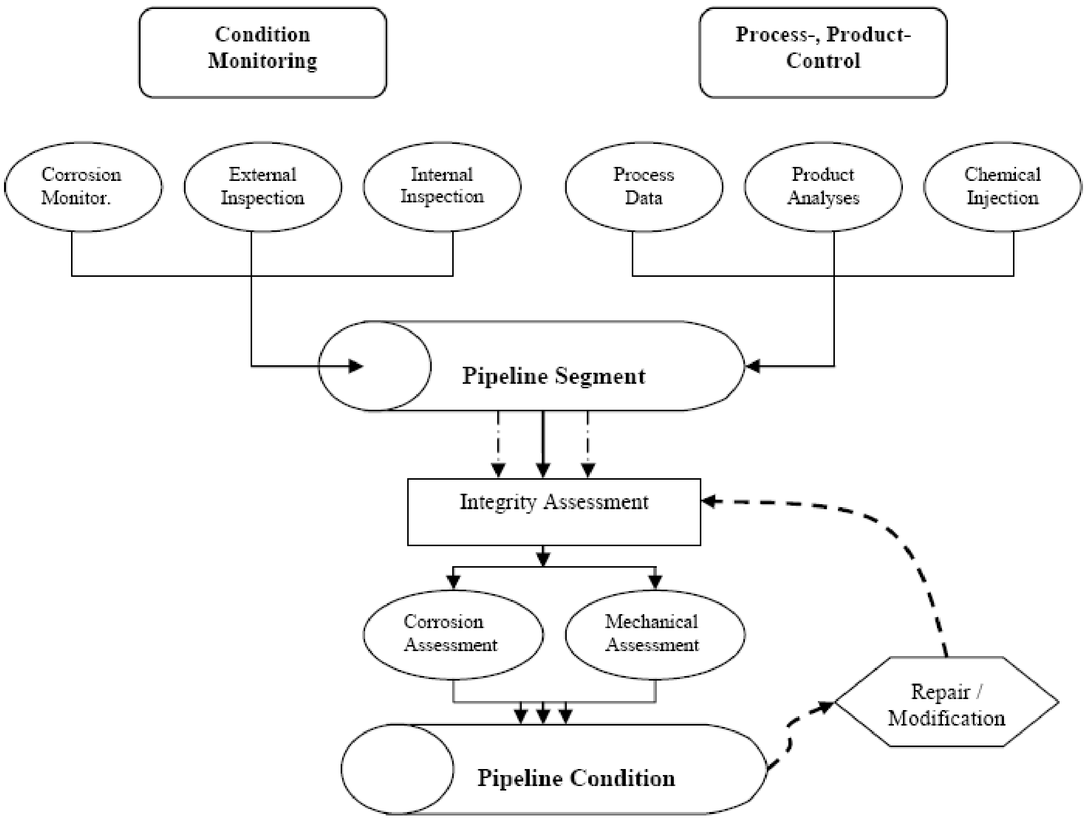


Figure 22: Activities necessary to control the integrity of the pipeline system [8]

Cathodic protection, [91]
External corrosion is controlled by the use of coating in combination with a cathodic protection system in case of coating damages.

The recent installed cathodic protection systems have very few reported problems. Where problems have occurred, for example with field joints, the cathodic protection system usually has sufficient capacity to provide the additional current demand while still achieving the required life. With the release of the latest revisions of the cathodic protection standards from DNV, ISO and

NORSOK, this has now changed. A large measure of the conservatism, particularly in respect of coating breakdown, has been removed, and significant reliance is placed on achieving high standards of coating application. The move to high integrity coatings, and the removal of conservatism from the design codes, may lead to use of pipeline anodes with much wider spacing than hitherto. However, it must be realised that the attenuation equations used to calculate, and sometimes to justify, wide anode spacing rely on knowing the conductance of the coatings used. While estimates of conductance for new coatings could be obtained, little data appear to be presently available in the public domain. Values for coatings after some years in service can only be guessed. Research focused on determining conductance on new and aged coatings, together with actual measurement of attenuation on in-situ pipelines would be valuable.

Testing of welding, [81]
For the girth welding of pipes, welding procedure qualifications regarding mechanical and corrosion properties are well specified. More often DNV-OS F-101 makes the basis for the extent of the qualifications. Testing is performed on as welded test specimens and on specimens that are deformed to simulate the installation process. The latter is also artificial aged to simulate ageing of line pipe material during operation. Testing of deformed and aged material is related to operational issues.

7.3 Literature review with respect to flexible risers

From the reviewed documents concerning offshore industry applications, ref. Table 39 and

Table 42 in Appendix C, there are a few documents treating risers in connection to ageing or life extension, see Table 16:

Table 16: System/context documents reviewed

Documents/reference	Flexible riser topics
Reports	
SEAFLEX, *Flexible Pipes. Failure modes, inspection, testing and Monitoring,* [76]	Degradation mechanism, failure modes, maintenance, and recommendations for life extension assessment
SINTEF, *Robust material selection in the offshore industry – flexible risers,* [81]	Degradation mechanisms, failure modes and system description.

7.3.1 Standards etc.

The governing standards for design, fabrication, installation and operation of flexible pipes are the API 17J and 17B specifications. These specifications are now in the process of being re-issued as ISO standards.

The early operational temperature limitations were not conservative and problems were experienced with ageing of the PA 11 plastic material (nylon) when used as pressure barrier. Operation outside humidity and related temperature limits has occurred causing reduced service life and riser replacement. The ageing causes embrittlement and cracking of the pressure barrier.

In order to establish safe operational limits for PA-11 pressure barriers, research and development work were initiated, resulting in revised ageing curves. API 17TR2 gives reasonable correlation between predicted and actual ageing of PA-11. Test coupons machined from actual flexible riser structures installed in gas injection and oil production lines and retrieved for testing have partly verified good correlation between actual degradation and the API 17TR2 predictions when the curve for pH 4 is applied.

Recent research shows that the ageing of PA-11 is more complicated than assumed in API TR 17TR2, even though adherence to the recommendations in API TR 17TR2 seems to be giving a significant reduction of ageing damages. More research is needed to establish more refined, less conservative and practical recommendations.

Ageing of the external sheath due to UV-exposure may be a long term problem even if this is not reported to be a significant problem today. Ageing of anti wear tape used between the armor layers may be a problem for pipes operating with high temperature, especially if the annulus is filled by condensed water diffused from the pipe bore, or filled by breaches in the external sheath.

Failures due to ageing of other polymer materials used in the flexible pipes are rarely seen compared to the PA-11 / Nylon failures. Adherence to the recommendations in API 17J/B is important if ageing problems should be avoided.

Failure due to material hydrolysis of bend stiffeners made of polyurethane has been experienced. Changes in type of polyurethane material used and increased knowledge of temperature limitations appear to have solved this problem.

For integrity management of risers, DNV is in the process of completing a recommended practice document.

7.3.2 System specific degradation mechanisms and failure modes

Flexible risers in operation are subjected to a number of degradation mechanisms that are limiting for the useful service life.

Due to the complicated and composite structure of a pipe wall, a large number of degradation mechanisms are possible. In this section mechanisms as known from service experience and full-scale tests are described. Focus is on failure modes that are related to material properties and material selection.

With respect to flexible riser fatigue, it should be noted that for the Norwegian offshore sector with close to 200 flexible risers, the average riser has been in service for only about 50% of its intended service life (typical design service life is 20 or 25 years) [75].

API 17B RP lists and describes all of the most probable failure modes and defects for a flexible pipe, see Table 17.

Failures have also been experienced with pipe clamps where the highly pre-stressed and anode protected bolts have cracked due to hydrogen embrittlement [75].

Figure 23 gives an overview of different failure modes in operation from an UKOOA report where data from a large number of fields covering both UK and Norwegian sector of the North Sea were collected.

Table 17: Failure modes and mechanisms for un-bonded flexible pipes (API 17B RP, [75])

Global failure	Possible failure mechanisms
Collapse	• Collapse of **carcass** and/or **pressure armor** due to excessive tension • Collapse of **carcass** and/or **pressure armors** due to excess external pressure • Collapse of **carcass** and/or **pressure armor** due to installation loads or ovalisation due to installation loads • Collapse of **internal pressure sheath** in smooth bore pipe
Burst	• Rupture of **pressure armors** because of excess internal pressure • Rupture of **tensile armors** due to excess internal pressure
Tensile failure	• Rupture of **tensile armors** due to excess tension • Collapse of **carcass** and/or **pressure armors** and/or **internal pressure sheath** due to excess tension • Snagging by fishing trawl board or anchor, causing overbending or tensile failure
Compressive failure	• Birdcaging of **tensile armor wires** • Compression leading to upheaval buckling and excess bending
Overbending	• Collapse of **carcass** and/or **pressure armor** or **internal pressure sheath** • Rupture of **internal pressure sheath** • Unlocking of interlocked **pressure armor layer** or **tensile armor layer** • Crack in **outer sheath**
Torsional failure	• Failure of **tensile armor wires** • Collapse of **carcass** and/or **internal pressure sheath** • Birdcaging of **tensile armor wires**
Fatigue failure	• **Tensile armor wire** fatigue • **Pressure armor wire** fatigue
Erosion	• Of **internal carcass**
Corrosion	• Of **internal carcass** • Of **pressure armor** or **tensile armor** exposed to seawater, if applicable • Of **pressure armor** or **tensile armor** exposed to diffused product

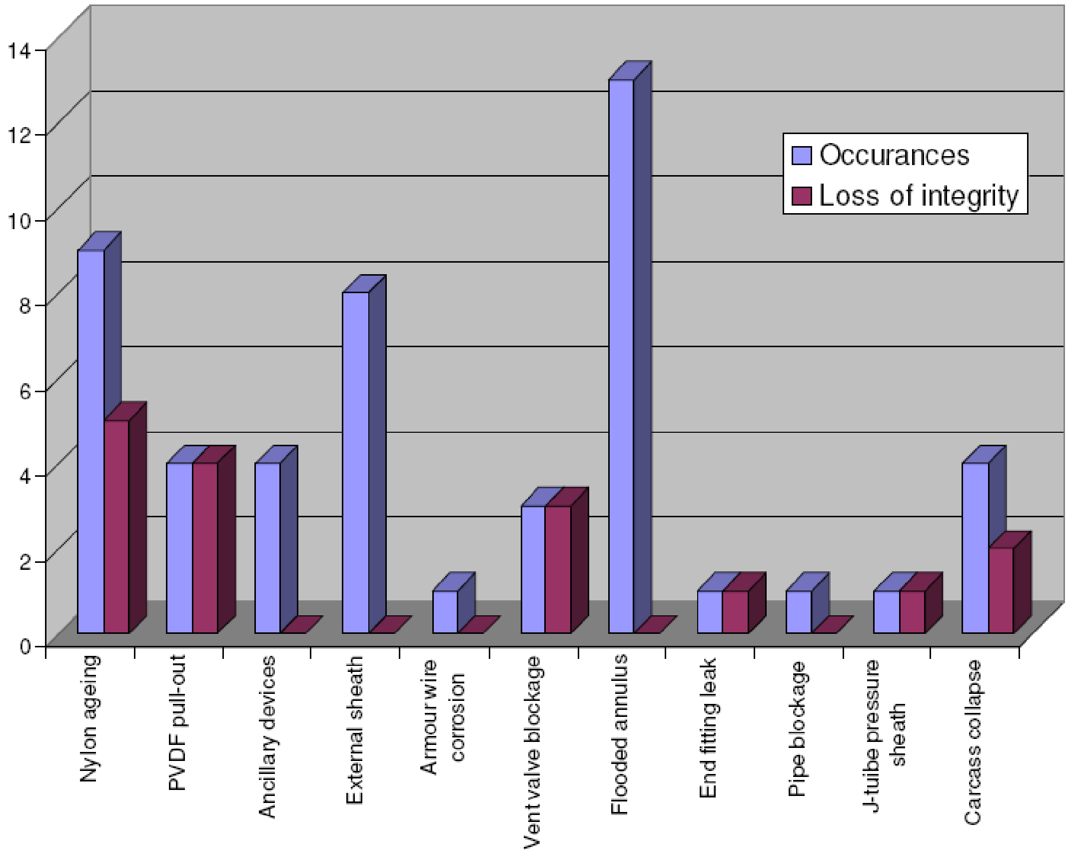


Figure 23: UKOOA statistics on riser operational failures, UK + Norway [75]

7.3.3 Barrier degradation mechanisms and failure modes

Carcass

The carcass may be subjected to a large number of failure modes; overstretching, fatigue, radial collapse, wear, erosion, corrosion and damage from pigging and similar operations.

Fatigue or wear damage of the carcass has not been reported in the open literature. Due to the structure and loading on the carcass, fatigue is not a likely failure mode, except as secondary damage due to initial damage in the production phase or due to pigging or the like.

The carcass may be subjected to erosion and erosion-corrosion in production risers for gas-condensate fields with sand production. Full scale tests have demonstrated significant material loss under conditions representing realistic operational conditions. Prediction tools have limited accuracy, and the design envelope for safe operation is uncertain.

The full scale tests have shown that corrosive environments with CO_2 will give enhanced erosion rates. Plain corrosion has not been reported for the carcass.

Liner

Rilsan® (PA11) is until now the most used liner-material in flexible risers. There are several degradation mechanisms for polyamide like thermal degradation, oxidation, photo degradation, absorption of water etc. However, for PA11 in the actual humid environment free of oxygen, the dominating process will be hydrolysis. Hydrolysis results in scissoring of the polymer chains and cause brittleness of the material. There has been large uncertainty about how to predict hydrolysis rate in order to ensure 20 years life time of the product. The hydrolysis rate increases rapidly with temperature and somewhat less with increasing sourness. Most of the failures related to degradation of Rilsan (as on Njord) however, seem to have been caused by underestimated water content in the fluid. In addition, Atofina claims on their web page that there has never been documented a flexible pipe failure caused by failure of polyamide-11 operated within the recommended service window. The operators however claim that there were large divergences between different aging models until the API TR 17 RUG was prepared by the Rilsan User Group – founded in 1998 consisting of a large number of operators and suppliers.

Sealing and fixation of the liner in the end termination has proved to be a problem. Improved end coupling design has appeared to alleviate the problem of liner pull-out. However, with improved fixation, fatigue crack growth through the liner has become a possible failure mode. Due to the short history of the improved design, no pipe design has yet been proved through service history to have a 20 year design life. More work into the mechanisms of sealing and fixation in the end termination should be undertaken.

Liner materials are subjected to long term deterioration mechanisms, like hydrolysis, deplastification creep and ageing. In order to meet ever more challenging operational conditions, new material grades of thermoplastics are being introduced at a rate which does not allow accumulation of service experience. Thus, qualification is to a large extent based on accelerated tests under simulated conditions. The methods used for qualification testing and the design criteria should be evaluated critically.

Pressure armor
In a pipe that is subjected to cyclic bending, the contact points of the profile will slide cyclically, with considerable contact stress. Due to the varying bending, the contact pressure will vary cyclically. This is a problem particularly for the Zeta profile where the contact stress causes cross-wire bending. The sliding may thus result in significant cyclic stresses in the cross-wire direction and possibly fatigue failure. The fatigue life may be affected by fretting at the contact points. The associated failure mode is cracking parallel to the wire axis.

Ovalisation of the pipe due to curvature variations and possibly side loads from a bend stiffener or a bellmouth will give cyclic stresses longitudinal to the armor profile, and possible fatigue cracking normal to the axis of the armor.

The presence of aqueous environments with H_2S and/or CO_2 may have a significant effect on fatigue strength. Such environments are probable. Gas will permeate through the liner from the high pressure well flow. Fresh water may also permeate from the bore, or there may be sea water ingress through damage in outer sheath.

At the contact points the armor may be subjected to wear.

Tensile armour
Possible failure modes for tensile armor may be listed as: overload in tension, possibly in combination with internal pressure, causing tensile failure overload in bending or compression causing wire disarray or birdcaging overload in torsion causing unwinding of armor or birdcaging fatigue corrosion fatigue fretting fatigue wear hydrogen induced cracking corrosion.

The overload modes of failure are not related to material properties, but to design and operational conditions.

No cases of service failure due to fatigue of tensile armor have been reported in the open literature. On the other hand, very few dynamic risers on the Norwegian Shelf have seen more than ten years of service loading, which is approximately 50% of a typical design life.

Over bending combined with high hydrostatic pressure (deep water) and compression have lead to failures of the tensile armour wires by overstressing or wire buckling. This failure mode, which is only applicable for deepwater, is referred to as lateral buckling, [75].

Armor wires
Fatigue of armor wires is in many cases a limiting factor for the design life of flexible risers. A pipe annulus may contain species that are aggressive with respect to steel, and which could affect fatigue strength significantly. In a consistent design methodology these effects should be taken into account.
The environmental factors which should be considered may be listed as follows:

- Sea water flooding of the annulus, due to leakage of the outer polymer sheath. Depending on the nature of the leak, and distance from the leak, sea water in the annulus could be depleted of oxygen, or possibly saturated with air. Efficiency of cathodic protection is likely to decay rapidly at some distance from the leak. Over the same distance Oxygen content also is likely to become reduced, due to restricted flow of water and consumption. Sea water may be combined with H_2S and/or CO_2 due to permeation from the product flow.
- Permeation of species from the product flow, notably water (H_2O) which may condense and accumulate in the annulus, in combination with permeated H_2S and/or CO_2.
- Risers which have been subjected to sea water ingress may be repaired, flushed with inhibitor and re-installed. Inhibitor fluid, possibly with some residual sea water and with H_2S and/or CO_2 due to permeation from the well flow, could have a detrimental effect on residual fatigue life.

Outer sheath
Leakage by damage of the outer polymer sheath, caused during installation or operation, or by malfunctioning venting valves. This would lead to sea water flooding of the annulus. Depending on the nature of the leak and the distance from the leak, sea water in the annulus could be depleted of oxygen, or possibly saturated with air. Efficiency of cathodic protection is uncertain. Sea water may be combined with hydrogen sulphide (H_2S) and/or carbon dioxide (CO_2) permeating from the bore. There is also a possibility for Microbial Induced Corrosion (MIC) as sulphide reducing bacteria (SRB) may develop in stagnant seawater.

For a flexible riser subjected to cyclic bending, the outer sheath will experience the largest cyclic strains. The outer sheath is also at a low temperature, and is thus conceptually vulnerable to damage. However, no fatigue failures of the outer sheath due to normal operational conditions have been reported.

Above the waterline, the outer sheath may be subjected to direct sunlight, which may cause ageing. However, this has not been reported as a problem.

On the other hand, a large number of failures have been reported, due to two main reasons:

- Damage due to rough handling, impact, etc. during installation or operation.
- Failure of the venting system, causing pressure build-up in the annulus and failure of outer sheath by bursting.

Water ingress has also been caused by malfunctioning or even lacking venting valves.

We also refer to Appendix D for different degradation mechanism and failure modes relevant for flexible risers in general.

7.3.4 System specific LE assessment

No specific assessments for flexible risers are found in the literature review. However [75] highlights the following recommendations based on experiences from life extension projects:

- Keep track of all documentation for every specific riser through out the full life span, including design, fabrication, installation, maintenance and operation
- Keep a log of the usage of the flexible pipe, re-termination, repairs, movement and changes etc. If the pipe is moved to another location keep all documentation from previous sits
- Keep all time traces of temperature and pressure relevant for each specific flexible pipe
- Keep a log of chemical usage in the flexible pipe, synchronised in time such that temperature may be estimated together with use of e.g. methanol

7.3.5 Maintenance & ageing related to flexible risers

API 17B and API 17J list a large number of tests that are relevant for qualification of flexible risers. Some of these tests are non-standard, and described in the API documents.

It should be noted that damaging interferences with neighbouring risers has been experienced during installation and recovery of flexible pipes. The consequences have been damages to the external sheath, loss of subsea anchor position/integrity and loss of buoyancy modules. Careful planning, training and execution are required to prevent such failures, especially during replacement operations on floaters with several risers and mooring lines [75].

Inspection

Inspection methods currently in use for flexible pipes in operation offshore are:

- Subsea ROV general and close visual inspection
- Deck level manual general and close visual inspection
- Climber close visual inspection (above water)
- Internal remote camera inspection

Testing

Testing methods currently in use for flexible pipes in operation are:

- Pipe pressure testing after installation, modifications, repair etc.
- Annulus vent function testing in order to detect blocked or malfunctioning vent valves, vent ports or problems with the vent system pipe work
- Annulus vacuum or pressure testing to identify intact external sheath and estimate liquid content
- Annulus gas sampling and analysis to identify annulus environment and possible corrosion processes
- Age testing of polymer coupons exposed to production and/or injection flow
- Bore fluid composition test to reveal content of CO_2 and H_2S etc.

Monitoring

Monitoring methods currently in use for flexible pipes in operation offshore are:

- Pipe bore pressure monitoring, pressure drop between subsea and topside sensors and pressure gradients/cycles
- Pipe bore temperature monitoring, temperature gradients/cycles

- Annulus vent flow pressure and flow monitoring
- Environmental load monitoring and/or floater motion and offset monitoring
- Bore flow rate, especially in relation to pressure drops

Repair
Repair methods for flexible pipes:
- Dry repair of external sheath damages by plastic welding and replacement sheath sections
- Dry repair of external sheath damages by stainless steel clamps
- Wet installation of a variety of external sheath repair clamps by ROV or divers
- Wet installation of a rigid steel clamp to strengthen pipe and seal of the external sheath by divers
- Wet installation/casting of plastic clamp to seal off external sheath damages
- Disconnection, retrieval and dry-termination of end fittings
- Re-establishing of annulus vent by drilling new vent access in the end fitting, epoxy filling ports or through the external sheath

7.4 Literature review with respect to Subsea Production Systems

Subsea equipment treated in this section is described in Section 7.1.3. From the reviewed documents concerning offshore industry applications, ref. Appendix C, there are a few documents treating subsea equipment in connection to ageing or life extension, see Table 18:

Table 18: System/context documents reviewed

Documents/reference	Process topics
Articles	
Ageing of materials, [91]	Degradation mechanisms
Reports	
DnV, *Joining methods – Technological summaries*, [10]	Welding of stainless steels for subsea applications (page 33)
DnV, *Material risk – Ageing offshore facilities*, [8]	Degradation mechanisms, failure modes and maintenance of subsea equipment

7.4.1 System specific degradation mechanisms and failure modes

Template
Templates are normally made from low alloy carbon steel and protected against corrosion by a combination of coating and sacrificial anodes. For the Norwegian continental shelf, the templates are integrated units with manifold and external fishing gear protection for protection of wellhead systems and the manifold.

Except from corrosion template degradation mechanisms are related to unfavourable effect of load combinations and operation outside original design criteria such as change in foundation due to sea bed erosion, new tie-ins and external impact from BOP loads or TPD [8].

Failure modes from corrosion are related to lack of electric continuity to all protected parts or coating not intact leading to excessive anode consumption. Also anodes may fall off after some time in operation due to inadequate design/quality [8].

Manifold
For the Norwegian sector of the North Sea the manifold is an integral part of the template and it can be a retrievable unit from the template. The manifold is a safety critical element and involves a number of mechanical components (valves, connectors, and sensors) in addition to the manifold piping [8] .

The **manifold piping** is often made from 22Cr Duplex and 25Cr Super Duplex materials, with external hydrogen induced stress cracking (HISC) as the main degradation mechanism. There have been a number of activities in order to get an understanding of the failure mechanisms of components made of such materials. A recommended practice (DNV RP F-112 Design of duplex stainless steel subsea equipment exposed to cathodic protection), were released in October 2008 in order to avoid such failures. Current recommendations have today a conservative approach with respect to allowable working stress level in the material. When the metallic pipe material is exposed to seawater (i.e. insulation deteriorated) and the CP is not sufficient, this will lead to accelerated degradation of the pipe [8].

Degradation of **insulation** can in addition to HISC be due to the combination of absorbed seawater with elevated temperature due to hot produced fluids or from mechanical damage (TPD, operation, deflection and strain absorbed by pipe material causing cracking, etc.) [8].

For the **mechanical moving components** degradation mechanisms involves degradation of material, marine growth, and calcareous deposits. This can lead to increased friction and wear and subsequent leakages to sea from actuator housings. With respect to the internal environment, internal corrosion and erosion are considered the most relevant failure mechanisms [8].

Subsea X-mas trees
Ref. Chapter 6.

Control system
Subsea control modules are frequently replaced. The average lifetime is in the order of less than 10 years. Failure of the control module causes the wells to be shut down. Common failures are failures in electronics and electrical connectors, failure in control valve and internal leakage.
Over time, failure in cables for power and signal transmission due to migration of water through insulation, etc., may take place. Degradation of the control system takes place due to wear, exposure to sea water and well fluids, high temperatures, hydraulic fluids, etc.

Subsea separation and boosting
No experience available due to limited time in operation (< 5 years).

7.4.2 System specific LE assessment

No specific assessments for subsea production equipment only are found in the literature review.

7.4.3 Maintenance & ageing related to subsea production systems

Literature findings related to maintenance and ageings related to various subsea production components is given below.

Template
Inspection programme should typically cover the following items [8]:

- The CP system; looking for excessive consumption of anode mass and damaged/missing anodes

- Recording of anode potential and steel if practically possible
- Coating damages, both due to general degradation and as effect of contact with fishing gear
- General damage to structure from fishing gear
- Hatches, handles and other elements that serve a function or can generate a snag point
- Inspect earth cabling used to ensure electrical continuity.

Manifold
Manifold inspection and testing shall cover following checks [8]:
- General condition to pipe coating
- General condition to components, valves, actuators and instruments
- Inspect all connector to trees and pipelines
- Pressure test
- Visual inspection to detect foreign objects.

Subsea X-mas tree
Ref. Chapter 6.

7.5 Life Extension assessment

7.5.1 Information on design, materials and operation

Reference is made to:
- NORSOK U-001- Subsea Production Systems, rev. 3, October 2002.
- ISO 13628. Petroleum and National Gas Industries- Design and Operation of Subsea Production Systems.
- NORSOKY-001 Subsea pipelines
- Offshore Standard DNV-OS-F101, Submarine Pipeline Systems, October 2007
- API 17B and 17J (flexible pipes)

Table 19 shows input information for pipelines, risers and subsea systems that is needed to perform the LE analysis, while Table 20 gives a detailed description of which process- and operation information that is needed. In addition the most actual condition monitoring sources are given.

Table 19: Important input information for pipelines, risers and subsea systems

TYPE OF INFORMATION					
DESIGN & INSTALLATION		**OPERATION**		**LIFE EXTENSION PERIOD**	
No.	**Description**	**No.**	**Description**	**No.**	**Description**
1	Material(s), protection, insulation	10	Info. about maintenance (repair) and modification	20	Info. about planned mainte-nance (repair) and planned modification
2	Design life calculations	11	Process/operation parameters	21	Process-/operation parameters (changes from design)
3	Drawings	12	Info. from condition monitoring	22	Changes in classification due to change in operation parameters
4	Valid standards and RP	13	Info. from inspection/testing	23	Length of Life Extension period
5	Operation and process info.	14	Info. from similar operation		
6	Installation loads	15	New standards and RP		
7	Installation accidents	16	New tools/design methods/ experience since design		
8	As-installed/built documentation				

Table 20: Overview of important information (process and operation) and actual condition monitoring sources

SYSTEM NAME	PROCESS PARAMETERS	OPERATION PARAMETERS	CONDITION MONITORING
Manifold piping, valves and connection to X-mas trees	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity	Solid particles Corrosion inhibitor Chemical addition Loads and vibration	CM Pressure and temperature Wall thickness Vibration Inspection
Control and monitoring systems		n/a	n/a
Template with protection structure (including other subsea structures)		Loads Support (soil cond.)	CP
Subsea separation and boosting systems	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity	Solid particles Corrosion inhibitor Chemical addition Loads and vibration	CM Pressure and temperature Wall thickness Vibration Inspection
Subsea power and frequency converters	n/a	n/a	n/a
Control umbilical	Fluid composition		Pressure Electrical resistance
Flowline (multiphase)	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity	Solid particles Corrosion inhibitor Chemical addition Loads and vibration	CM Pressure and temperature Wall thickness Vibration Inspection Stress/strain
Pipeline (processed or partly processed)	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity Dew point	Corrosion inhibitor Loads and vibration	CM Pressure and temperature Wall thickness Vibration Inspection Stress/strain
Riser	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity	Corrosion inhibitor Loads and vibration	CM Pressure and temperature Wall thickness Vibration Inspection Annulus vent[1)]

[1)] Flexible pipes

7.5.2 Evaluation of ageing mechanisms and failure modes

Table 21 below shows the most relevant degradation mechanisms for the subsea systems.

Table 21: Summary of the most relevant degradation mechanisms for the well completion systems

SYSTEM NAME	MOST ACTUAL DEGRADATION MECHANISM [1,2)]
Manifold piping, valves and connection to X-mas trees	A, B5, B6, D1, E1, F1, F2, F3, G, H, I, K, L
Control and monitoring systems	B4, B5, B6, F2, G, I, L
Template with protection structure	B5, B6, I

SYSTEM NAME	MOST ACTUAL DEGRADATION MECHANISM [1,2]
(including other subsea structures)	
Subsea separation and boosting systems	A, B4, B5, B6, D1, F1, F2, G, H, I
Subsea power and frequency converters	B4, B5, B6, F2, G, I, L
Control umbilical	B1, B2, B4, B5, B6, F1, F2, G, I
Flowline (multiphase)	A, B1, B5, B6, D1, E1, F1, F2, F3, G, H, I, L
Pipeline (processed or partly processed)	A, B1, B5, B6, D1, E1, F1, F2, F3, G, H, I, L
Riser - bonded	A, B1, B5, B6, D1, D2, E1, F2, F3, H, I, L
Riser – unbounded (flexible pipe)	A, B1, B5, B6, C, D1, D2, E1, F2, F3, G, H, I, K, L

1) See List in Section 3.1
2) Depending on actual material used

7.5.3 Maintenance for pipelines, riser and subsea equipment

Various maintenance actions for pipelines, riser and subsea equipment are reviewed.

Upgrade
Repair and/or replacement of components or complete piping systems are a possible outcome from the analysis. This also includes upgrade of the cathodic protection system (sacrificial anodes) and repair of damages in flexible pipes.

Monitoring
Monitoring process and operation parameters is important for the pipeline, riser and subsea system.

The most important process parameters to monitor are:

- Pressure
- Temperature
- Content of solids (sand)
- Fluid composition (inclusive water content)

For rotating equipment like e.g. pumps and compressors and other components under varying load condition monitoring through vibration analysis is an important diagnostic tool.

Corrosion monitoring based on the ER-principle (FSM-Roxar and RCCP-Cormon) or UT (Ultramonit-Sensorlink) has been installed subsea. The Sand detection and/or erosion monitoring based on the ER-principle are also used on subsea wellhead piping.

Inspection
The inspection program for subsea pipelines and flowlines is often based on a RBI analysis. For internal inspection intelligent pig is most frequently used. Another method for short pipelines and riser is video/camera inspection.

Visual inspection with diver or video/camera is often used for external inspection. Thickness measurement with UT and methods for detection of surface defects by use of ROV is also used.

Maintenance
The output from the LE analysis can also be an update of the maintenance program.

Testing
Pressure testing can be used to verify that the systems fulfil the defined pressure requirement. Pressure testing is frequently used to control the integrity of the flexible pipes. Testing is also used to control the functionality of valves (e.g. safety valves).

7.6 Challenges and lack of knowledge

The following possible challenges/concerns should be addressed to increase the state of knowledge for pipelines, risers and subsea production systems:

- Subsea production systems
    - Structural integrity monitoring system
    - Sand disposal system
- Methods for subsea inspection
    - Structures
    - Pipelines
    - Flexible pipes
- Reliable corrosion monitoring system for installed pipelines

8 Topside process equipment

The LE process for process systems is now investigated. First, a description and break down of the system is given. Then the literature review of LE for these systems is summarised. Next we comment on the various steps of the LE process. In particular we point out the most relevant degradation mechanisms for each part of the system, i.e. sub-systems (considered as barrier element), and see how the generic results of Chapter 2 can be applied.

8.1 System description

The process system can be separated in the main hydrocarbon system and utility systems. NORSOK Standard P-100 “Process systems” contains a list of actual systems. These systems are listed in Table 22. P-100 contains a detailed description of the equipments belonging to the different systems (not repeated in this document).

Table 22: List of main HC system and utility systems from NORSOK P-100

SYSTEM NAME	SYSTEM NO.	BELONGS TO
Topside flowlines and manifolds	16	Main hydrocarbon system
Separation and stabilisation	20	
Crude handling	21	
Gas compression	23, 26, 27	
Gas treatment	24	
Gas conditioning	25	
Water injection	29	Utility systems
Cooling medium	40	
Heating system	41	
Chemical injection	42	
Flare	43	
Oily water treatment	44	
Fuel gas	45	
Methanol injection	46	
Chlorination	47	
Sea water	50	
Fresh water	53	
Open drain	56	
Closed drain	57	
Compressed air	63	
Inert gas	64	
Hydraulic power	65	

Figure 24 shows a schematic lay-out of a typical main hydrocarbon system. This system is proposed divided into six (6) main blocks which individually can be analysed:

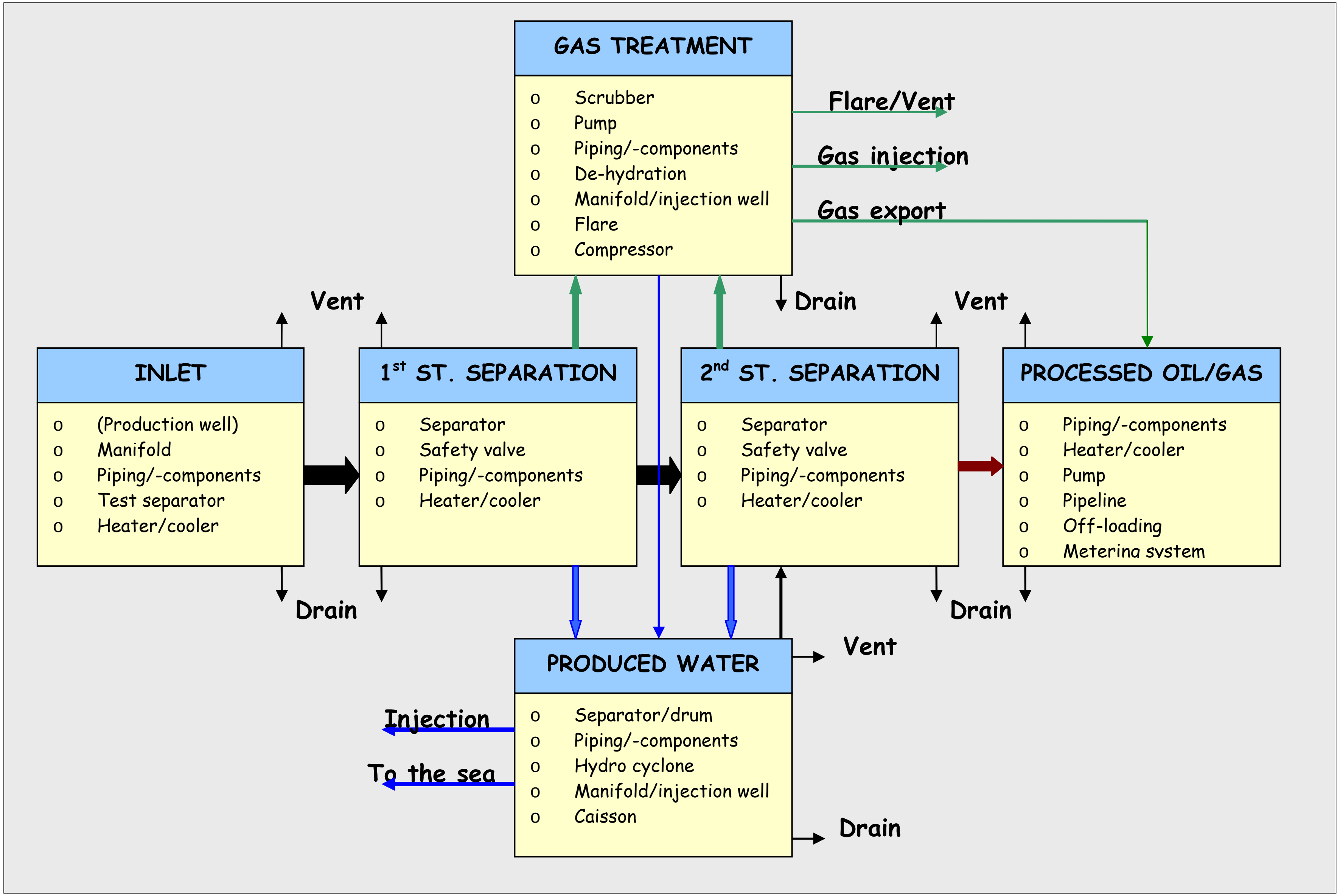


Figure 24: Schematic layout of the main HC system

1. **Inlet** – from wells through flowlines and the manifold and to the inlet of the 1st Stage Separator (including Test Separator and heater) [*System 16*]
2. **1st Stage Separator** – oil/gas line from inlet to inlet 2nd Stage Separator [*System 20*]
3. **2nd Stage Separator –** oil/gas line from inlet 2nd Stage Separator to heater/cooler on crude oil/gas line [*System 20*]
4. **Processed oil/gas –** from heater/cooler and onward until export [*System 21*]
5. **Produced water –** water from Test Separator, 1st Stage Separator, 2nd Stage Separator and Gas Treatment System and to injection or seawater disposal including all equipment [*System 44*]
6. **Gas treatment system –** gas from Test Separator, 1st Stage Separator and 2nd Stage Separator through the complete system ending up at gas injection and/or export [*System 23, 24, 25, 26, 27*].

The life extension assessment shall principally be done for all the systems given in Table 22 including all the main units within each system. However, a screening should preferably be done to reduce the workload during the LE analysis for the process system. One simple procedure is to use ”acceptable” and ”not-acceptable” consequence as the screening parameter independent of failure or non-failure. The result will be a list of systems to be included in the LE analysis and systems not to be further analysed. ”Acceptable” and ”non-acceptable” consequence needs to be defined in advance.

8.2 Literature review with respect to process equipment

There are a number of threats to integrity on topside topside process equipment that increase with the age of a facility; corrosion, erosion, wear, environmentally assisted cracking, fatigue, physical damage, materials deterioration, blockages, fouling and scaling, and defective equipment [91].

Corrosion is a major hazard for topside steelwork, usually protected by paint and coatings. The state of these coatings is an issue for LE, since loss of steel wall thickness could lead to possible structural collapse [68].

Most of the internal corrosion problems in process equipment and piping are associated with the corrosive contents of the produced well fluids, such as dissolved gases e.g. CO_2 and H_2S. The constitution of the well fluids changes with life and older fields tend to be sourer, leading to an increasing rate of corrosion [91].

[23] identifies the following process equipment with high probability of failure due to ageing:

- Pressure vessels
- Boilers
- Piping and pipe work
- Flexible hoses
- Storage tanks
- Protective features and buildings.

Results from [13] show the following contribution of the most dominating ageing mechanisms and ageing effects for some equipment classes on a nuclear plant:

- Accumulators: Gasket failure (42%), float control valve wearing (23%), instrumentation fittings/joints (11%), weld failure (9%), contamination in fuel (7%), corrosion (galvanic and general) (4%)
- Tank failures: Instrumentations fittings/joints (46%), weld failure (36%), galvanic corrosion (9%), general corrosion (9%)
- Vessels: Corrosion (34%), weld failure in liner (33%), weld crack (22%), anchor bolt failure (11%)
- Summary of HPI failure causes from NPE, NPRDS, LERs and plant-specific data: Wear (28%), Improper lubrication (18%), Corrosion (18%), time-related degradation (11%), dirt (11%), fatigue (7%), misalignment (5%), improper maintenance (4%).

For examples of ageing mechanisms, and how to detect them for different equipment, see Appendix C of [77].

From the reviewed documents concerning offshore industry applications, ref. Appendix C, there are a few documents and guidelines treating process systems in connection to ageing or life extension, see Table 23:

Table 23: System/context relevant documents

Documents/reference	**Process topics**
Articles	
Ageing of materials, [91]	Overview of degradation mechanisms.
Managing life extension in ageing offshore Installations, [85]	Degradation mechanisms and ageing effects. Vessel example
Reports	
DOE&EPRI, *Ageing Management Guideline for Commercial Nuclear Power Plants – Tanks and Pools*, [13]	Degradation mechanisms and failure modes
HSE, *Plant Ageing* [23]	Degradation mechanism, failure modes and examples of LE assessment and maintenance.
Poseidon, *Recommendations for design life extension regulations*, [69]	Degradation mechanisms steelwork
TWI, *Requirements for Life Extension of Ageing Offshore Installations*, [87]	Addresses main process equipment, technical safety (active and passive fire protection, fire and gas detection) and the structure in this area in connection to ageing and extended life.

8.2.1 Standards

NORSOK P-100 Process equipment, Rev. 02, November 2001
NORSOK M-001 Material Selection, Rev. 01 – 04 (04 – August 2004)

8.2.2 System specific degradation mechanisms and failure modes

Ageing effects of topside equipment in general include, but are not limited to [85], [87]:

- Wear of moving/rotating equipment, pumps and compressors
- Reducing corrosion allowances (in vessels and pipe work)
- Reducing erosion allowances (on valve seats and other high velocity areas).

The ageing process includes not just a general degradation of systems but also includes the change of demands on the system posed by evolving requirements and circumstances, which can include the following:

- Changing production demands:
    - Reservoir fluid variations
    - Water cut increase (may change from approximately 0% to 90%)
    - Reservoir fluid variations
    - Production fluid temperatures rise
    - Additional cooling requirements.
- Oil becoming sour, leading to
    - Accelerating corrosion
    - Safety impacts due to toxicity.

[21] points out different types of corrosion, erosion, fatigue, creep and wear as relevant degradation mechanisms for topside equipment.

Below, we sum up degradation mechanisms and failure modes for specific topside process equipment found in the reviewed documents.

HC system
Over 60% of leaks on HC systems are caused by ageing processes such as fatigue, corrosion, erosion, degradation [87].

Lifting equipment
Fatigue and other ageing (e.g. wear) of lifting equipment components increases the likelihood of component failure (e.g. gears, bearings, brakes, shaft, cables, slings etc.) [87].

Storage tanks
If not properly maintained, tanks can suffer corrosion leading to wall thinning, particularly in unprotected, coastal or damp locations. Where the level of fluid oscillates over a narrow range, the walls of tanks have been known to develop fatigue cracks at eh liquid level [23] .

Non-metallic storage tanks (e.g. high-density polyethylene or polypropylene) need to be considered for atmospheric deterioration, as they can become embrittled and crack over a long period in ultraviolet sunlight. The possibility of internal chemical attack should also be considered, as should creep at ambient temperature [23] .

The probability of corrosion of pressure vessels for the storage ammonia and chlorine is well recognised, but careful management and inspection of their containment is still required. LPG tanks are regarded as non-corrosive, but there have been a few instances of cracks/corrosion from other sources and contaminants where integrity management has lapsed [23].

Pressure vessels and boilers
Like tanks, unprotected vessels are susceptible to corrosion, fatigue and wall thinning, particularly at crevices, external supports and saddles. Liquid impinging onto a surface from a height or passing through a nozzle at high velocity can cause erosion and well thinning to affected areas. Vibration and fretting of heat exchanger tubes are well known, yet often poorly managed. In heated vessels and boilers, temperature gradients and differences can be a source of thermal fatigue as found, for example, in varying firing boilers. Some heat transfer conditions can result in accelerated corrosion rates [23].

Figure 1 in [85] shows typical degradations and production changes with time on a vessel.

Piping (and pipework systems)

Piping and pipework are, statistically, the source of most leaks and loss of containment in systems containing hazardous fluids or pressure. However, piping and pipework systems are often excluded from inspection. If not properly managed, piping and pipework can be susceptible to damage form corrosion (internal and external), erosion, fatigue, creep, accumulated plastic deformation, leakage from gaskets, loose fittings, loss of insulation or protective coatings, mechanical damage, internal scaling or fouling. Fatigue of small-bore attachments can be a particular problem where there is vibration from rotating equipment or flow-induced vibration, [23].

8.2.3 System specific LE assessment

Fitness-for-service (FFS) assessment (also known as Engineering Critical Assessment or ECA) is a re-evaluation of the structural integrity of an item of equipment for further service, taking into account damage and deviations from design basis. The objectives of an FFS assessment are similar to LEA, i.e. to determine whether equipment is safe in its current condition, predict lifetime given that further damage may occur and install suitable inspection and monitoring programme, [23], [87].

There are many fitness-for-service assessments concerning specific equipments, ref. [23] page 19. One of most commonly procedures and the most relevant for the purpose of this project (i.e. for structural process equipment and welded component) is the API Recommended Practice 579 (2000) used for metallic equipment, pressure vessels piping and tankage, [23] .

API 579 is a standard for pressure containing equipment in the refining and petrochemical industries. In 2007 API and ASME produced a joint update called API 579-1/ASME FFS-1 (2007) which include all topics in API 579 in addition to FFS assessments addressing damage mechanisms experienced in other industries.

8.2.4 Maintenance & ageing related to topside process equipment

Discussions upon maintenance&ageing are given in Appendix B.3.1 and Appendix B.3.2, respectively.

8.3 Life Extension assessment – Topside process equipment

8.3.1 Information on design, materials and operation

For facilities designed and put in operation since the NORSOK Standards were introduced late 1990-ties, the material selection has been based on NORSOK M-001. This document describes which materials to be used for the different systems including pipings and units (components) given in Table 22. However, the alternative materials described in M-001 differ from the materials that originally were selected for the elder facilities in the Norwegian Sector of the North Sea. Table 24 shows a broad summary of the main materials used before NORSOK M-001 and after M-001 was introduced.

Step 1 of the Life extension procedure describes in general terms the Background Information (from Design and Operation phase) that need to be collected and reviewed before any Life Extension analysis is started. For the process system the information described in Table 25 need to be collected and systemised.

In addition information about Process- and Operation parameters as described in Section 3.1.3 is important to make available. The referred list is a general list of important parameters. Table 26 contains a detailed list of the important process and operation parameters for the process system to be collected.

Finally the process system has different types of condition monitoring system in place. Section 3.2.2 gives a general overview of the most important information that can be retrieved. Table 26 also includes a list of the most important condition monitoring sources for the different systems.

Table 24: Main material selection for hydrocarbon and utility systems – before and after introduction of NORSOK M-001

SYSTEM NAME	SYSTEM NO.	BEFORE M-001	WITH M-001
Topside flowlines and manifolds	16	Carbon steel with some stainless steel in the gas systems	Carbon steel Stainless steel (AISI 316, 22% Cr, 25% Cr, 6Mo) Inconel 625 overlay Titanium GRP or plastic lining
Separation and stabilisation	20		
Crude handling	21		
Gas compression	23, 26, 27		
Gas treatment	24		
Gas conditioning	25		
Water injection	29	Carbon steel 22% Cr	Carbon steel Carbon steel with lining/coating Stainless steels (13% Cr, 22% Cr, 25% Cr) GRP
Cooling medium (not seawater)	40	Carbon steel AISI 316	Carbon Steel AISI 316
Heating system	41	Carbon steel AISI 316	Carbon Steel AISI 316
Chemical injection	42	Carbon steel AISI 316	Carbon Steel AISI 316 6Mo Titanium
Flare	43	Carbon steel AISI 316	Carbon Steel AISI 316 6Mo Alloy 800HT
Oily water treatment	44	Carbon steel GRP	Carbon steel GRP 6Mo Titanium 22% Cr and 25% Cr AISI 316 (no oxygen)
Fuel gas	45	Carbon steel	Carbon steel
Methanol injection	46	Carbon steel AISI 316	Carbon Steel AISI 316
Chlorination	47	Titanium Plastic material	Titanium Plastic material
Sea water	50	Carbon steel Carbon steel + lining Cu-alloys Stainless steels (AISI 316, 22% Cr, 6Mo)	Stainless steel (25% Cr, 6Mo) Cu-alloys Titanium GRP Ni-alloys
Fresh water	53	Carbon steel AISI 316	AISI 316
Open drain	56	Carbon steel	Carbon steel GRP
Closed drain	57	Carbon steel	***No oxygen:***

SYSTEM NAME	SYSTEM NO.	BEFORE M-001	WITH M-001
			Carbon steel or AISI 316 ***With oxygen:*** GRP 6Mo Titanium 22% Cr and 25% Cr
Compressed air	63	Carbon steel AISI 316	AISI 316
Inert gas	64	Carbon steel	Carbon steel AISI 316
Hydraulic power	65	Carbon steel	Carbon steel AISI 316

Table 25: Important input information for the process system

TYPE OF INFORMATION					
DESIGN & INSTALLATION		**OPERATION**		**LIFE EXTENSION PERIOD**	
No.	**Description**	**No.**	**Description**	**No.**	**Description**
1	Material(s), protection, insulation	10	Info. about maintenance (repair) and modification	20	Info. about planned maintenance (repair) and modification
2	Design life calculations	11	Process/operation parameters	21	Process-/operation parameters (changes from design)
3	Drawings	12	Info. from condition monitoring	22	Changes in classification due to change in operation parameters
4	Valid standards and RP	13	Info. from inspection/testing	23	Length of Life Extension period
5	Operation and process info.	14	Info. from similar operation		
6	Installation loads	15	New standards and RP		
7	Installation accidents	16	New tools/design methods/ experience since design		
8	As-installed/built documentation				

Table 26: Overview of important information (process and operation) and actual condition monitoring sources

SYSTEM NAME	SYSTEM NO.	PROCESS PARAMETERS	OPERATION PARAMETERS	CONDITION MONITORING
Topside flowlines and manifolds	16	Oil/water/gas composition Temperature & pressure CO_2/H_2S content and pH Oxygen & chloride cont. Velocity Dew point Bacterial activity	Solid particles Corrosion inhibitor Chemical addition Loads and vibration	CM[1)] Wall thickness Vibration Inspection
Separation and stabilisation	20			
Crude handling	21			
Gas compression	23, 26, 27			
Gas treatment	24			
Gas conditioning	25			
Water injection (deaerated sea water)	29	Oxygen Temperature Pressure	Chemical addition (oxygen scavenger) Vibration	CM[1)] Wall thickness Inspection Vibration
Cooling medium (not seawater)	40	Chloride content Temperature		CM[1)] Inspection
Heating system	41	NA	NA	Inspection

SYSTEM NAME	SYSTEM NO.	PROCESS PARAMETERS	OPERATION PARAMETERS	CONDITION MONITORING
Chemical injection	42	Oxygen content	NA	Inspection
Flare	43	NA	NA	Inspection
Oily water treatment (produced water)	44	Temperature Pressure	Corrosion inhibitor	CM[1)] Inspection Wall thickness
Fuel gas	45	NA	NA	Inspection
Methanol injection	46	NA	NA	Inspection
Chlorination	47	Residual chlorine level Temperature	NA	Inspection
Sea water	50	Temperature Residual chlorine level	NA	Inspection
Fresh water	53	Chloride level	NA	Inspection
Open drain	56	NA	NA	Inspection
Closed drain	57	Oxygen content	NA	Inspection
Compressed air	63	Water content	NA	Inspection
Inert gas	64	Water content H_2S content	NA	Inspection
Hydraulic power	65	NA	NA	Inspection

[1)] Corrosion Monitoring

8.3.2 Evaluation of ageing mechanisms and failure modes

For the process system all the degradation mechanisms described in Section 3.1.1 are valid. However, the most frequent degradation mechanisms are:

- B – Corrosion
- C – Creep
- D – Flow induced induced metal loss
- E – Fatigue
- F – Hydrogen related cracking
- G – Material deterioration (polymer gaskets)

Table 27 shows a summary of the most relevant degradation mechanisms for the different systems. However, which degradation mechanism that will occur depends on the actual material(s) and the operation conditions.

Table 27: Summary of the most relevant degradation mechanisms for the process system

SYSTEM NAME	SYSTEM NO.	MOST ACTUAL DEGRADATION MECHANISM [1,2)]
Topside flowlines and manifolds	16	A, B1, B3, B5, B6, B7, C, D1, D2, F2, G
Separation and stabilisation	20	
Crude handling	21	
Gas compression	23, 26, 27	B3, B5, B6, C, E2, G,
Gas treatment	24	
Gas conditioning	25	
Water injection (deaerated sea water)	29	B1, B3, B4, B5, B6, D2, D3, E2
Cooling medium (not seawater)	40	CE, CF
Heating system	41	C2, C5, C6, C, E2, G
Chemical injection	42	B2, B4, B6
Flare	43	B5, B6, C, E1, E6, J
Oily water treatment (produced water)	44	B1, B3 (?), B4, B5, B6,
Fuel gas	45	B3, B5
Methanol injection	46	B5, B7

SYSTEM NAME	SYSTEM NO.	MOST ACTUAL DEGRADATION MECHANISM [1,2]
Chlorination	47	B2, B6
Sea water	50	B1, B2, B4, B5, B6, D2, D3
Fresh water	53	B5, B6
Open drain	56	B1, B4, B5, B6, E2
Closed drain	57	B1, B2, B4, B5, B6, E2
Compressed air	63	B5, B6, E2
Inert gas	64	B5
Hydraulic power	65	B2 (external), B5, B6

1) See List in Section 3.1
2) Depending on actual material used

8.3.3 Maintenance for topside process systems

Upgrade
Repair and/or replacement of components or complete systems are a possible outcome for components in the process system. This also includes upgrade of coating and insulation systems.

Monitoring
Monitoring process and operation parameters is important for the process system. The most important parameters to monitor are:

- Pressure
- Temperature
- Content of solids (sand)
- Oxygen
- Salt (resistivity)
- Fluid composition (inclusive water content)

For rotating equipment like e.g. pumps and compressors and other components under varying load condition monitoring through vibration analysis is an important diagnostic tool.

Finally corrosion and erosion monitoring with ER-probes and/or UT-sensors are often used. Weight Loss Coupons are also often installed to monitor the corrosivity of the fluid and/or the effect of corrosion inhibitor.

Inspection
The inspection program is normally established based on a RBI analysis. Different methods are used to inspect the process system. *Visual inspection* is most frequent used to establish a global (and local through Close Visual Inspection) external status of a system. For surface defects not clearly visible, dye penetrant and magnetic particle testing is often preferred. To inspect inside compartments with restricted access, video and/or boroscope can be used.

To examine possible "failures" inside a material or inside a component a range of NDT techniques are available. The most frequent used techniques are UT and radiography. Chapter 3.2 of [23] gives a short description of available methods including the preferred method(s) relative to a known degradation mechanism.

Maintenance
The output from the LE analysis can also be an update of the maintenance program.

Testing
Pressure testing is often used to verify repair of piping system and to verify that the component fulfil the defined pressure requirement. Testing is also used to control the functionality of valves (e.g. safety valves).

8.4 Challenges and lack of knowledge

The following possible challenges/concerns should be addressed to increase the state of knowledge for the topside process system:

- Corrosion Under Insulation
  - Reliable inspection methods
  - Design of insulation system (incl. insulation material and surface coating)
- Fatigue of small bore piping due to vibration
  - Construction of small bore piping
  - How to avoid small bore piping with high weights?
- Systems (monitoring equipment, modelling) for estimation of remaining fatigue life of components under varying loads
- Inspection and monitoring methods for composite materials
- Effective NDT methods for
  - Welds on duplex stainless steel
  - Complicated components like e.g. valves
  - Heat exchanger tubes/plates
- Non Invasive Inspection (NII) of pressure vessels
- Souring of well fluid due to increased H_2S content from injection water break through
  - How to “follow” the integrity of the materials in the system due to the increased H_2S content?
- Inspection and monitoring of wear on pumps and compressors
- Optimisation of maintenance planning through combining Reliability Centered Maintenance (RCM) and RBI
- More reliable estimation of material degradation through combining modelling, monitoring and inspection
  - Development of degradation models
  - Availability of reliable monitoring and inspection data (including information about accuracy)
- More use of “noble” alloys like e.g. stainless steel, nickel alloys and titanium require to establish “safe operation windows”
  - For the actual alloys and environments: Which combination of operation parameters will give a safe operation with low probability of failure?
- Sand production
  - Modelling of erosion caused by sand particles
  - Equipment for quantification of sand content in a flow.

9 Safety systems

The LE process for safety systems is now investigated. First, a description and break down of the system is given (from a barrier point of view). Then the literature review of LE for these systems is summarised. Next we comment on the various steps of the LE process. In particular we point out the most relevant degradation mechanisms for each part of the system (barrier element), and see how the generic results of Chapter 2 can be applied.

9.1 System description

The following systems are covered in the NORSOK S-001, Technical safety:

- Structures
- Containment
- Open Drain
- Process safety
- Emergency Shut Down (ESD)
- Blow down (BD) and flare/vent system
- Gas detection
- Fire detection
- Ignition source control (ISC)
- Human-machine interface (HMI)
- Natural ventilation and Heating, ventilation and air conditioning (HVAC)
- Public Address (PA), alarm and emergency communication
- Emergency power and lighting
- Passive Fire Protection (PFP)
- Fire fighting system
- Escape and evacuation
- Rescue and safety equipment
- Marine systems and position keeping
- Ship collision barrier.

Some of the above systems (e.g. Escape and evacuation) are mentioned in Chapter 4 and discussed with respect to obsolescence issues.

NORSOK S-001 [50] also has specific chapters on management and layout. The present report will restrict to safety systems that are somehow related to the process and we suggest to arrange these in the following set of "barriers", see Figure 25:

1. Containment (i.e. process integrity).
2. Process Control system (PCS), incl. alarms and operator intervention.
3. Process protection systems, as Process Shut Down (PSD) system, Pressure Relief Valves (PSV).
4. FGD/ESD-system, incl. isolation, Blow Down, ignition source control (ISC), HVAC.
5. Active fire Fighting Equipment (FFE), including firewater monitors, firewater pumps, ring main, deluge, etc.
6. Passive fire protection systems, including firewalls, passive fire protection, open and closed drains, etc.
7. Escape and evacuation routes.

8. Rescue and safety equipment.

In order to maintain the integrity of the process, the first barrier will be the continuously operating PCS. Then additional barriers are introduced as "shells" according to when they are activated after a process upset. Note that we have chosen to include PC system as one of the "barriers". The PCS is in particular important in order to reduce the number of demands on the "true" safety systems such as PSD, ESD and FGD.

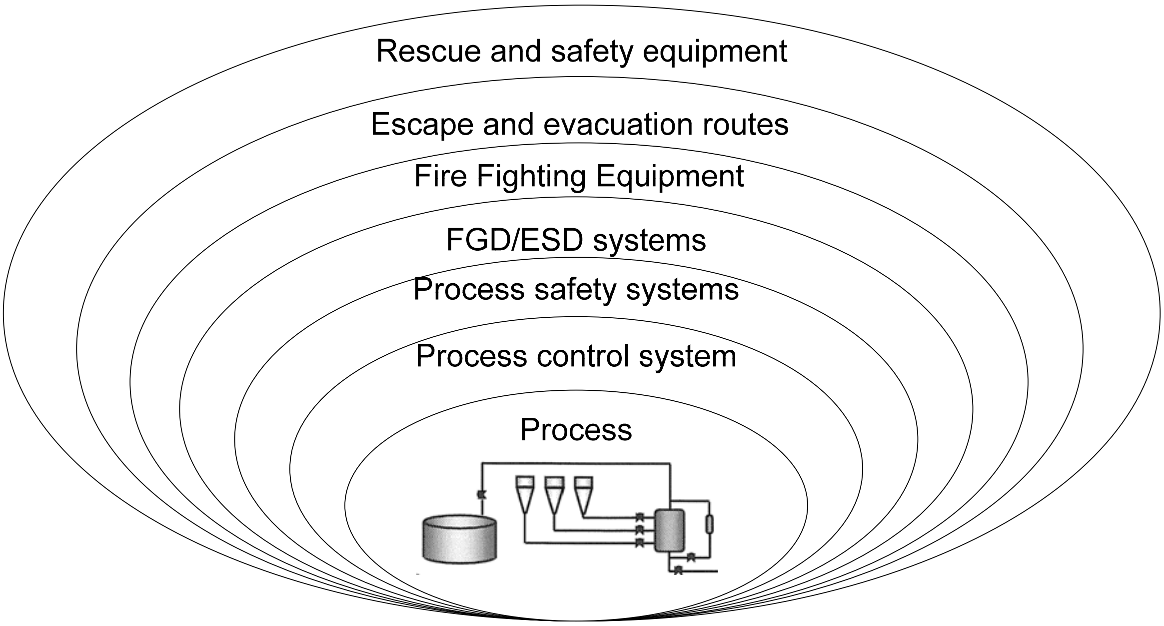


Figure 25: Safety "barriers" – "The onion model"

Barrier 1 (containment) is treated in Chapter 8, and the barriers 6 - 7 will not be discussed in the present report. So below we restrict to consider the barriers 2-5, with focus on 2-4. These will be broken down into barrier elements, which are analysed according to the life extension process.

Main safety systems related to the course of events resulting in an accident:

- Process control, incl. condition monitoring (CM)
- PSD system
- PSV
- ESD and FGD (Fire and Gas Detection) systems

Note that we here include PC system as a "barrier"; as this is important for the number of demands on the safety systems. A typical PC and safety systems configuration is illustrated in Figure 26 (simplified).

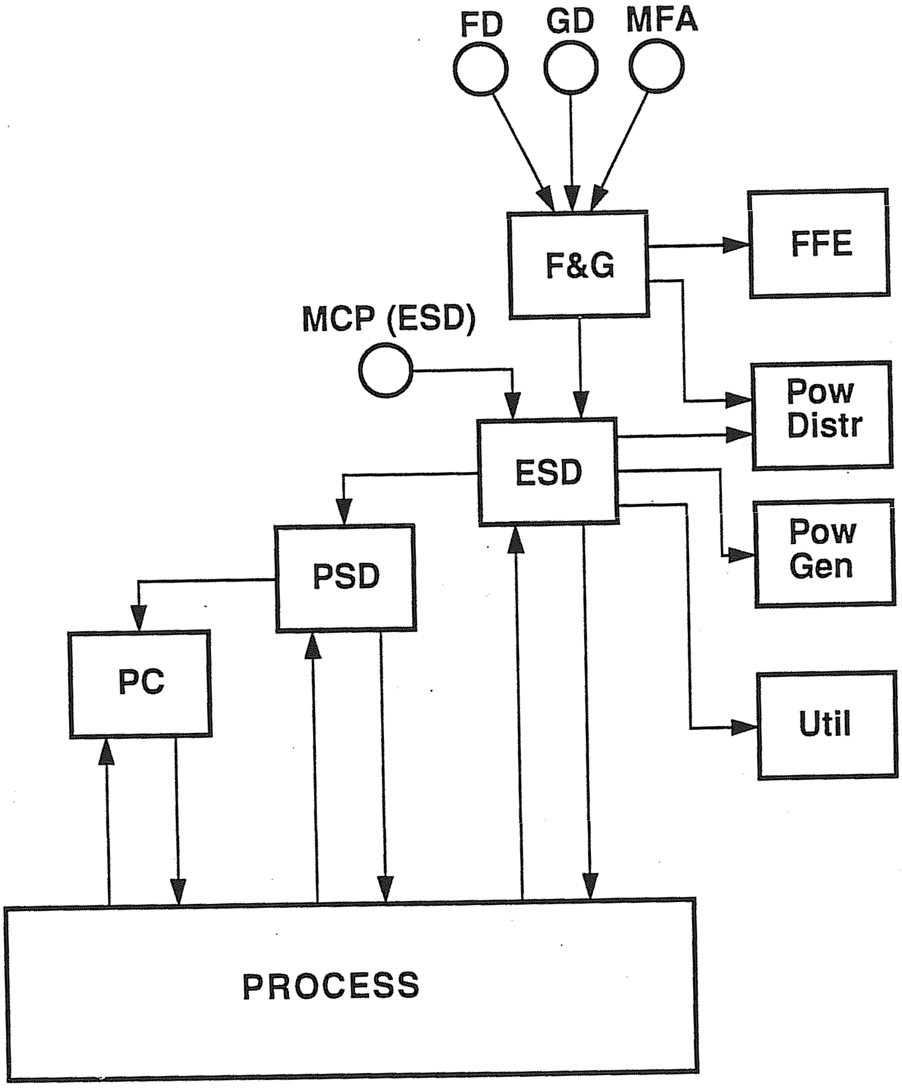
The four subsystems ("barriers") discussed here are broken down as follows:

- Process Control (PC) system:
  - Electronics, incl. cabling
  - Sensors (pressure, temperature, flow, level) , condition monitoring
  - Actuators (valves)
  - Alarms
  - Human interface

- Process safety systems
    - Process sensors (transmitters/switches)
    - PSD logic, incl. cabling
    - Pilot/solenoid valves
    - PSD actuators (Shutdown valves)
    - PSD, bursting discs and FSV (check valves)
    - Power
    - Human interface.
- ESD, FGD, etc.
    - ESD logic and cabling (incl. PB)
    - FGD sensors (gas detectors, fire detectors)
    - Ignition Source Control (ISC)
    - ESVs
    - Isolation and blow down
    - HVAC
    - Power.
- Fire fighting equipment, etc. (cf. NORSOK S-001, [50])
    - Firewater supply system
    - Firewater pump arrangement
    - Deluge system
    - Sprinkler system
    - Foam system
    - Manual fire fighting
    - Hydrants and hose reels
    - Helideck fire fighting system
    - Extinguishing systems in enclosed compartments
    - Water mist system
    - Gaseous agents
    - (Passive fire protection)
    - (Open drain).

In this report, we only address briefly the bullets concerning the active fire fighting system. However, it should be noted that experiences show that the performance of the passive fire protection, for instance, has been rather reduced due to ageing and degradation mechanisms such as corrosion, scaling, delamination and chipping.

It should be noted that many components are similar for the different sub-systems, e.g. valves, logic (ESD and PSD) and detectors.



MFA: Manual Fire Alarm
GD: Gas Detector (HC, O_2, H_2S, etc.)
FD: Fire Detectors (smoke, flame, heat, etc.)
F&G: Fire and Gas
FFE: Fire Fighting Equipment (fire pumps, ring main, deluge, etc.)
MCP: Manual Call Point (Manual ESD command)
ESD: Emergency ShutDown
PSD: Process ShutDown
PC: Process Control

Figure 26: Process control and safety systems configurations (simplified)

9.2 Literature review: LE for safety systems

From the reviewed documents concerning offshore industry applications, ref. Table 39 and

Table 42 in Appendix C, there are a few documents and guidelines treating safety systems in connection to ageing or life extension:

Table 28: System/context documents

Document ref.	Safety system topics
Articles	
Ageing of materials, [91]	Overview of degradation mechanisms.
Reports	
COWI, *Ageing rigs – Review of major accidents. Causes and barriers,* [7]	Electronic and mechanical equipment, degradation mechanisms learnt from historical accidents.
HSE, *Plant Ageing,* [23]	Degradation mechanism and failure modes.
TWI, *Requirements for Aging Offshore Installations,* [87]	Addresses main process equipment, technical safety (active and passive fire protection, fire and gas detection) and the structure in this area in connection to ageing and extended life.

Note that [87] also lists topside barrier systems seen as critical to the safety on a typical oil and gas production facility, ref. Table 3, page 14 in [87]. These are essentially systems as descried above.

9.2.1 Standards (safety systems)

The NORSOK Standard on Technical safety, (NORSOK S-001) describes the principles and requirements for the development of the safety design of offshore facilities for production of oil and gas. This standard may also be used for mobile offshore drilling units.

NORSOK S-001, [50] together with ISO 13702, [37] defines the required standard for implementation of technologies and emergency preparedness to establish and maintain an adequate level of safety for personnel, environment and material assets.

The NORSOK standard also gives a number of references to standards constituting provisions and guidelines that shall be used unless otherwise agreed. Some of the most important are:

- API RP 14C. Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms.
- IEC 61508, [33]. Functional Safety of electrical/electronic/programmable electronic safety related systems
- IEC 61511, [34]. Functional Safety – Safety Instrumented systems for the process industry.
- OLF Guidelines No. 70. Guidelines for the application of IEC 61508 and IEC 61511 in the petroleum activities on the continental shelf.

In particular, IEC 61508/61511 and the OLF guideline 070, give specific safety requirements on various safety systems; specifying Safety Integrity Level (SIL), which impose both qualitative and quantitative requirements. The quantitative requirement is normally given in terms of the maximum PFD (Probability of Failure on Demand), i.e. the probability that the safety function fails upon a demand. It will be essential for LE approval to demonstrate that these requirements are maintained during the LE period.

9.2.2 Degradation mechanisms for safety related equipment

Below, we sum up degradation mechanisms for safety critical systems found in the reviewed documents.

Process control
Degradation of equipment is usually strongly linked to the process operating conditions in terms of the environment, loads and duty. Process control is therefore an important part of the equipment management strategy. Its aims are to ensure that equipment operates within its safe operating limits, while optimising performance and minimising degradation, and it is a key instrument to prolonging equipment life [23].

Process conditions are often changed over the life of a plant, maybe as a result of changes in product, process or capacity. There may also be changes in conditions at times of shutdown, start-up, cleaning/decontamination. It is important to recognise and review the impact of such changes, and good co-operation between operators, maintenance and materials engineers is a significant part of process control [23].

Electronic equipment
Safety instrumented systems consists of electronic equipment, such as control panels and sensor systems. All types of electronic equipment consist of components with a finite life time. Therefore the performance of equipment will degrade with time. Usually defective electronic components cannot be repaired but have to be replaced. Some systems (such as modern control panels) have self-testing features. Control panels are also postponed to wear [7].

Protective devices
Safety valves, bursting discs, level gauges, pressure relief equipment including vent lines and stacks and other devices are vital means for protecting equipment against overpressure and are often an indicator of problems elsewhere in the system. Protective devices are prone to ageing mechanisms such as fouling, condensation and calibration inaccuracy [23].

ESD, PSD and Blow-down valves
Degradation mechanism for valves (including shut down valves and pressure relief valves) are wear and corrosion. ESD and blow-down system valves and pipework may operate less efficiently due to wear, corrosion, fouling etc. [87].

All types of barriers which rely on mechanical equipment will be prone to degradation over time, e.g. closing mechanisms /ventilation and ballast valves). The moving parts become worn, lubrication deteriorates with time, friction increases and corrosion appears. Proper maintenance remedies these effects [7].

Fire and gas detectors
Reduced sensitivity of gas, smoke and fire detectors with age due to poisoning of sensors, mechanical damage, window deterioration (in infra-red detectors) [87].

Fire fighting system
The fire fighting system is briefly described below with respect to ageing and degradation, all based on lectures on the seminar “Safety challenges of ageing facilities”, Stavanger October 29-

30, 2008. This includes challenges during upgrading/modification, main degradation causes, and finally specific degradation mechanisms and challenges for fire pumps, ring main and deluge system, respectively.

Examples of challenges in upgrading/ modification of the fire fighting system are:

- Does the fire fighting system have sufficient capacity according to the possible scenario? Changes in the definition of possible scenario from design/ previous modification may require more fire pumps or increased capacity of the pumps. The fire scenario may be reconsidered, due to new knowledge, increased production or changes in production parameters (e.g. production of gas instead of oil).
- Which requirements should be fulfilled, the latest or the requirements from the date when the facility was designed?
- Are the possible accident scenarios similar to what the fire fighting system originally was designed for?
- Is the capacity of the existing sprinkler system sufficient?
- Combination of existing and modified/new equipment, how much of the equipment should be modified?
- Design and modification documentation doesn't exist.
- Modification of the fire fighting system may cause unbalance
- Experiences have shown that redesign is preferred instead of repair or replacement of the existing system.
- Before and after a modification of the fire fighting system, it is important that updated as-built documentation is available. Such documentation is often hard to find.

The main causes of reduced performance of the fire fighting system are

- Corrosion, leading to clogged nozzles
- Marin growing leading to increased friction and clogged nozzles
- Degraded fire pumps, generator or control valves.
- Repaired and replaced components/equipment may reduce the system functionality according to the original system.

Some of the sub-systems (ref. NORSOK S-001) are briefly described below with respect to ageing and degradation:

Fire pumps
Fire pumps degrade due to erosion, corrosion (causing the failure mode leakage) and marine growing.

Ring main
The ring main is a complex system of pipes/hoses and is therefore difficult to monitor and to get a complete overview of. The ring main on ageing facilities, where different modifications have been performed during the facilities service life, is often rather complex and contains several cross sections.

Deluge system
The main challenges of ageing deluge systems are clogged nozzles, due to corrosion, sediments and marine growing. Subsequently this will reduce the system performance on an actual demand. Maintenance (inspection) of the fire fighting system is therefore important.

Testing (and the required testing frequency) of the deluge systems and their nozzles, is often said to increase the rate of degradation, corrosion and clogging of nozzles, as the testing carries (sea)water into the system which remains in the system. Alternative to original testing methods (and testing intervals) may be considered. However, the functional tests of safety systems or safety functions should be as near a real demand as possible.

Examples of compensating measures to reduce clogging of nozzles and hoses:
- *Corrosion*: Drainage, fresh water washing, strainer
- *Sediments*: Drainage, fresh water washing
- *Marine growing*: Hypochlorite injection, drainage, strainer

Table 29 below lists degradation mechanisms and failure modes for different barriers and barrier function according to [87].

Table 29: Barriers and effect of ageing [87]

Barrier	Barrier function	Ageing processes
Gas detection	Minimising HC leaks and reducing the risk of fire and explosion by detection of gas leaks to enable action to be taken	Degradation of gas detectors due to ageing (e.g. window deterioration)
ESD systems	Minimising the risk of fire and explosion by a system to shut-down operations in the event of a HC leak	Reduced capacity of the ESD system due to ageing processes (e.g. corrosion of valves)
Fire and smoke detection	Reduce the risk of escalation of fire by detection of fire and smoke to enable action to be taken	Degradation of fire and smoke detectors due to ageing processes
Active fire protection	Reduce the risk of escalation of fire by protection of the facility against fire by an active protection system	Fire water systems degrading due to corrosion
Passive fire protection	Reduce the risk of escalation of fire by protection of the facilities against fire by a passive protection system, including the use of materials protecting critical members from temperature rise	Loss of performance of PFP coatings due to ageing
Blast walls	Limiting the extent of an explosion and protecting critical equipment and personnel by provision of blast walls	Supports for blast walls deteriorating due to corrosion
EER	Enable the orderly evacuation form the facility if required by provision of EER facilities	Loss of performance of EER facilities (e.g. access ways) due to ageing processes (corrosion)

9.2.3 Failure modes

Failure modes for safety systems mainly belong to the category *Malfunction* (see Section 3.1.2). As pointed out there, this should be specified further for specific equipment, and we refer to the OREDA handbooks [63] and [64] and the PDS handbooks [66] and [67]. For instance for valves, typical failure modes are (also see Appendix E):

- Fail To Open (FTO)
- Fail To Close (FTC)
- Spurious operation (closing/opening)
- External leakage
- Internal leakage.

- Structural deficiency

These more specific failure modes should then be related to relevant physical degradation mechanisms. Similarly, for transmitters, frequent failure modes are:

- Fail to function on demand
- Erratic output
- High (Low) output.

Note that the OREDA handbook separates between critical and degraded failures, which can provide information to model degradation, using actual data.

Note that for safety assessment it is sufficient to distinguish between the failure modes *Safe* (spurious operation) and *Dangerous* (fail to operate on demand) for the safety systems; e.g. see standard IEC 61508. However, this is not a very fruitful categorisation with respect to ageing/degradation. Further, the standard distinguishes between detectable (by self test) and non-detectable failures. We certainly focus on the *non-detectable*, (that is not detected "immediately" by the built-in automatic self-test).

9.2.4 LE assessment for safety systems

IEC 61508/61511 both have a strong focus on the life cycle perspective; i.e. that safety shall be maintained throughout the entire life (all phases) of a plant. However, LE is not given specific attention in the standards.

There also exist *general* examples of life extension frameworks/assessment [77]. However, no LE assessments being relevant for safety critical equipment only has been found in the literature review.

9.2.5 Maintenance & ageing related to safety systems

Since safety systems are not in active use, they may have "dormant failures", and so testing is essential for these systems; (e.g. see IEC 61508, IEC61511, OLF 070). First, there shall be *functional testing* at regular intervals. Further, a lot of components have built in "self test" mechanisms, implying that several failures modes may be detected on line by these diagnostic features. For example erroneous or no output from a process sensor will often be detected by the system itself. The diagnostic coverage (DC) of the built in self test specifies the fraction of failures that will be detected by such tests.

With respect to manual functional testing it is often assumed that these tests have a coverage of 100%, i.e. all failures not covered by self testing will be revealed during functional testing. However, in practice also these tests are imperfect (e.g. PDS handbook).

9.3 Life Extension assessment for safety systems

We first comment on an example of the LE process for the process safety system. Next we give some general comments/findings relevant for LE of safety systems.

9.3.1 Life Extension Case: Process safety systems

The following barrier elements should be analysed for the process safety systems ("barrier" 3):

- Process sensors
- PSD logic, incl. cabling

- Pilot/solenoid valves
- PSD actuators (Shutdown valves)
- Pressure relief (PSV), bursting discs and FSV (check valves)
- Power
- Human interface.

Note that for safety systems it may be more efficient to sort and investigate the various systems according to “type of equipment” (e.g. transmitters, valves), as the same type of equipment may occur in various barriers. As an example, the following types of equipment are here considered for analysis (see Table 30):

- Process sensors
- Safety logic (PCS, PSD, ESD, F&G), incl. cabling, interface modules, I/O cards, relays, etc.
- Pilot/solenoid valves
- Valve actuators and valve body (Shutdown valves in PSD and ESD)
- Pressure relief valves (PSV), bursting discs and FSV (check valves)
- Power supply (electrical / hydraulic / pneumatic).

Table 30: Example of analysis of material degradation for safety systems

SYSTEM	COMPONENT	COMMENTS[2]	DEGRADATION MECHANISM(S)	FAILURE MODE(S)
PC / ESD / ESD / F&G	Logic (incl. I/O))	Safety logic / PLC	Excessive temperature / humidity	Spurious operation Fail to function on demand
		Relays	Fatigue due to high number of movements/cycles	Stuck No / low contact
		Cabling	Fatigue	
PC / PSD	Process transmitters	Piping connection, membrane (stainless steel), sensor, chamber, electronics, 20mA output signals	Blockage (of piping connection) Corrosion Fatigue (External vibration)	(Leakage through membrane/ chamber) Malfunction
PC / PSD / ESD	Pilot/Solenoid valves		Excessive growing Contamination Humidity Corrosion Fatigue / degradation Sticking	Fail to open Fail to close Spurious operation
PSD / ESD	Shutdown valve	Valve body	Internal environment (sand, hydrates, ice, etc.) Fatigue due to vibration etc. Erosion	Structural defiency Internal leakage External leakage
		Actuator	Fatigue Contamination of actuating medium	Fail to close Fail to open Clogging of supply / return line

Note that in the analysis of safety systems we should rather than PoF include “demand rate” and *PFD* (“Probability of Failure on Demand”) in the analysis. It is the product of the *demand rate* and the *PFD* that corresponds to PoF in the general case.

[2] Type of conponent, important subcomponens, voting, etc.

9.3.2 General information

We here focus on aspects that are specific for safety systems, and will not discuss in detail mechanical components, also treated in other parts of the report.

1. Information on design, materials and maintenance/operation

Some general information on design, operational conditions, etc, being relevant for LE of safety systems are summarised below.

- *Design*
  - Degree of redundancy is essential for safety systems. For instance “parallel measurements” of PT gives essential information for follow up; cf. monitoring. Further, redundancy may be required for safety valves to satisfy safety requirements (cf. SIL).
  - Voting logic (when there is redundancy) is essential for safety systems: one-out-of-two (1oo2) is much safer than two-out-of-two (2oo2), etc.
  - Transmitter vs. switch is important for safety; (transmitters giving better monitoring and for instance reduces danger of CCF).
  - Type of logic; now essentially computer based.
  - Valves (ESVs), for example how much actuator force has been included (i.e. safety margins), materials applied, use of passive fire protection on valves.

- *Demand-frequency* on safety system (frequency of fires, leaks) is relevant, and it should also be considered whether *systems triggering demands on safety systems* are affect by ageing.
  - Thus, control system is also relevant to investigate with respect to LE.
  - E.g. glycol systems deteriorate; i.e. giving more leaks (and thus higher demands on safety systems).
  - Number of cycles / movements for mechanical parts such as e.g. relays.

- *Functional testing* of safety systems is essential
  - Involves visual inspection and provides good opportunity to assess actual state.
  - Assumption of ”as good as new” after test is questionable, (at least for ageing equipment).
  - Quality of maintenance is important, in particular testing and inspection. Operator must demonstrate high quality of tests (and subsequent maintenance).
  - The SSC or barriers may degrade by the increasing number of functional testing as the equipment age.

- *Automatic self test* (for various safety systems components like logic and sensors) is important to detect various failures “instantly” (and essentially “remove” the effect of these, if handled effectively)
  - High degree of self-test preferred.
  - Frequency of self-tests should not be too high, as excessive self-testing may itself contribute to deterioration of some equipment, (example fire loop).

- *Operator competence* may prove critical; e.g. manning being reduced and partly moved onshore. Should be critically evaluated.

2. Evaluation of ageing, deterioration mechanisms and failure modes
A few points regarding LE evaluation are listed

- Actual *age*, i.e. *time since replacement*, gives essential information
  - Logic is often replaced (before design life).
  - PT and valves etc often not replaced.
  - Detectors: new optical; old types are catalytic.

- *Aging, failures* and *failure modes*
  - Electronics: a common assumption is that there is no ageing effect for these.
  - I/O relays deteriorate after a given number of operations (switches); cf. contact of Digital Output (DO) cards. Thus “age” for these components should be given as number of operations (of the relay). They are designed for a certain number of operations, and should then be replaced.
  - Beware of *leakage points*, e.g. transmitters.
  - Transmitter failure could be caused by wrong impedance.
  - State of *cabling* important and its state must be assessed; e.g. connections; (note: vibrations), water intrusion. This is particularly important as it can be the cause of CCF (and possibly not tested as regularly as most other equipment).
  - *Power supplies*: electrolytic condensers “dry out” and must be replaced.

3. Risk Assessment
It is a specific feature of the safety systems that they represent barriers for major hazardous events like fires and explosions (reducing probability and/or consequence). These systems themselves are seldom the cause of risk. However, the following is noted:

- Electric equipment in general is a well-known *cause* of fire.
- *Lightening* is a hazard (possible cause of safety system failures); also resulting in *CCF*. Thus, lightening protection is important.

Otherwise, the risk assessment should take into account the points listed above (in 1. and 2.). However, the need of detailed risk assessments is for many parts of the safety systems is considered to be moderate only:

- The ability to decide the state and also replace units if required is generally rather high for (modules of) the safety systems.
  - This should reduce the need for elaborate assessments of risk and LE. Priority should be given to systems not tested/inspected regularly, and to the quality of testing/inspection, (and follow up of detected deteriorations).
  - It could be a more serious challenge that components are outdated (taken out of production or not supported any more). Thus, system competence/knowledge may not be maintained. This is a challenge for LE that must be handled.

Further, for critical equipment being identified from above discussion it should be relevant to perform more detailed analyses than the one outlined in Chapter 2 and Chapter 3. This could imply further development and application of probabilistic Markov models (See Section 3.4) to predict the distribution for time to (critical) failure, conditioned on the current state of the equipment.

4. Maintenance and compensating measures
Here we focus on safety systems (PSD, ESD, etc.), and most relevant maintenance actions and compensating measures then are:

- Increased (more frequent) periodic (functional) testing
- More complete (higher quality) testing/inspection and follow up.
- Evaluate degree of and frequency of diagnostic self-tests.
- Replace / rebuild old systems, e.g.
    - Replacing switches with transmitters
    - Replace logic (if old type)
    - Introduce redundancy, (e.g. transmitters/detectors)
    - Replace old ESVs
    - Replace cabling.
- Introducing new *Indicators:*
    - ESVs and similar valves: *closing time* is considered a good indicator of valve status/degradation.

9.4 Challenges and lack of knowledge

The following possible challenges/concerns should be addressed to increase the state of knowledge for safety systems:

- The common assumption that tested systems are as "good as new" should be challenged for various equipment (both mechanical and electrical); not necessarily valid during an LE period.
- It is difficult to evaluate the quality of functional testing and inspection. So what is the actual "coverage" of the functional tests? (In many of today's analyses it is erroneously assumed that this coverage is 100%).
- The exact deterioration process and time to failure distribution is hard to assess, and new knowledge should be achieved by developing probabilistic models for system state of critical components, using real offshore failure data.
    - choice and fit of life time distribution
    - how to address common cause failures/simultaneous failures? For ageing facilities it is a concern that probability of failure for several components increase; so that several components may fail simultaneously, leading to multiple site failures.
- Lack of knowledge about ageing and ageing mechanisms for certain equipment types. For safety systems ageing of electronic systems may be a challenge.
- Approach for identifying status (remaining life) of cabling can be a challenge; (not subject to the same degree of testing as most equipment).
- *Obsolescence* can be a challenge as old control/safety systems are getting outdated. This will often result in lack of support and spare parts of old systems, and also that competence on system "disappears".

10 Conclusions

This chapter presents main tasks and possible challenges for operators applying for LE of an offshore facility. Relevant research and development (R&D) work is also indicated.

10.1 General tasks and challenges for the LE process

As a facility approaches the end of its design life, the operator must carry out various activities to assure technical, operational and organisational integrity of the facility during a possible LE period. The necessary main activities to provide for this are:

- Update the technology, operational procedures, etc. according to the requirements of today's regulations.

- Obtain knowledge about the state of the facility, find out how the integrity level is affected by ageing, degradation, obsolescence, etc, and next decide how to prevent the ageing phenomenas.

- Establish an LE management plan and follow-up the plan throughout the LE period until decommissioning.
    - The LE management plan shall take care of the extra activities to make sure that the facility's integrity level is maintained during the LE.
    - The LE management plan shall be adjusted to today's and (expected) future type of operation, organisation and requirements.

So it is required that the operator initiates a number of activities in order to carry out an LE, and first of all a good LE process must be established. Challenges could appear e.g. for the following tasks:

- Establish a good screening process; (which SSC are critical with respect to ageing?)

- Specify a good analysis for identifying obsolescence and organisational challenges as (e.g. providing a check list):
    - Will the facility meet weight challenges due to need of new equipment during extended production?
    - Will there be adverse effects of combining old and new equipment?
    - Will the personnel's competence/knowledge be maintained for old SSC?
    - Will there be spares available for all SSC?

- Establish a good process for identifying cost-effective measures to close identified challenges (gaps).

- Establish a reliable estimation of material degradation:
    - Provide *data* on the operational history and present condition of degradation
    - Establish good *models* to predict the future degradation (for main degradation mechanisms); based on the operational/process conditions. This includes modelling of the relation between degree of degradation and probability of failure (PoF).

- Also consider uncertainties and future changes being external to systems. Are there ageing mechanisms not related to the system itself, e.g. geological and geotechnical hazards, marine growth and climate/weather changes that should be included in the ageing analysis as well?

- Assure that safety will not be sacrificed during the LE period:
  - Provide knowledge and models to determine the effect of maintenance and modifications.
  - Establish data and methods for condition monitoring and inspection during the LE period. Decide which indicators to apply in the LE period to identify the level of degradation.
  - Carry out an overall risk assessment to assure that safety will not be sacrificed at any time in the LE period. Also establish (risk) acceptance criteria for when LE should be permitted.

- Provide sufficient competence to carry out the LE process and to follow up during the LE period.

10.2 Concerns and possible challenges for specific systems

In general the greatest challenges may be related to verification of structure and passive systems, as active systems topside usually are replaceable. Based on interviews with different companies in the industry, [84], three of the companies present the following as their greatest challenges with respect to ageing and LE:

- Passive fire protection
- Flexible pipes, cranes, structure, control system (spare parts)
- Wells and well integrity, structures/containment/piping, ESD/F&G systems, pumps, turbine and compressors

Specific challenges and concerns, identified for the various systems investigated in the present report are summarised below, (see previous chapters).

1. Material handling and cranes (obsolescence and organisational issues)
The following are important issues, which the operator must consider as part of an LE assessment:

- *Installation lay-out and logistics*. Is there more equipment on board, resulting in sight reduction or restricted lay down areas or material handling routes? Is there sufficient flexibility to meet possible future challenges with respect to logistic needs? Can plans for future layout changes cause challenges related to visibility for operator?
- *Material handling*. Does existing equipment comply with present and future needs and regulations?
- *Crane state*. Is there a possibility of some equipment getting outdated (e.g. lack of spares)? Will competence of relevant personnel be available?
- *Crane load*. Are changes anticipated for the LE period that severely will increase the crane utilisation?
- *Health, Safety and Environment*. Is the equipment acceptable for lifting or evacuation of personnel (according to current requirements)? Are working conditions for the crane operator (noise etc) according to current requirements? Will emissions comply with existing or future requirements. Will environmental changes result in increased wind, more waves or turbulence.

2. Wells (physical degradation)
The following are possible challenges/concerns regarding the state of knowledge for the well completion system:

- Lack of knowledge of material properties (including degradation mechanism)
- Methods for down hole inspection and monitoring of material behaviour
- Lack of knowledge of fatigue and fatigue models, especially fatigue of subsea wellheads and X-mas. How long is it reasonable to operate with respect to fatigue impact on the wellhead?
- Lack of knowledge of wear and wear models (wear in the production line due to rotating production string for platform wells and subsea wells and wear on risers for subsea wells due to rotating drill string).
- Lack of knowledge of loads during drilling, production and work over
- Lack of knowledge about geological effects from subsidence, such as "slippage" between layers (faults)
- Fatigue of wellhead and conductor casing including horizontal X-mas tree (subsea)
- Modelling of erosion caused by sand particles.
- **(Obsolescence and organisational issues):** Hand-over documentation and and transfer of critical information / essential well-data during licence acquisitions, change of operater and difficulties for key personnel.

3. Transport systems: pipelines and risers (physical degradation)
The following are possible challenges/concerns regarding the state of knowledge for pipelines and risers:

- Monitoring system structural integrity of subsea production systems
- Effect of sand disposal system (subsea)
- Methods for subsea inspection
- Reliable corrosion monitoring for pipelines

4. Process equipment (physical degradation)
The following are possible challenges/concerns regarding the state of knowledge for process equipment:

- Corrosion Under Insulation
- Fatigue of small bore piping due to vibration
- Systems for estimation of remaining fatigue life of components under varying loads; (monitoring equipment)
- Effective NDT methods for some equipment
- Non Invasive Inspection (NII) for pressure vessels
- Effect on integrity of material due to increased H_2S content
- Inspection and monitoring of wear on pumps and compressors

5. Safety systems
Safety systems have some challenges, differing from those of other systems. For instance, safety systems are in nature "dormant systems", requiring functional testing.

- The effect of functional testing must be considered. For instance, does the assumption "good as new" after testing hold for ageing equipment?

- It may be required to develop specific (probabilistic) degradation models, and this may represent a challenge:
  - choice and fit of life time distribution
  - How to address common cause failures/simultaneous failures? For ageing facilities it is a concern that probability of failure for several components increase; so that several components may fail simultaneously, leading to multiple site failures.
- Ageing of electronic equipment and cabling may represent a challenge.
- Obsolescence (“outdated” technology) can be a challenge for some equipment.

10.3 Knowledge gaps related to ageing

In this report the following knowledge gaps have been identified:

- Understanding and assessing degradation mechanisms and modelling of degradation mechanisms for various materials and equipment.
- Developing and applying reliable methods for subsea inspection and monitoring.
- Understanding and increasing awareness of common cause failures of equipment due to ageing.
- Assessing the effects of and utilising methods for monitoring of facility loads.
- Understanding ageing of electronic equipment and cabling.
- Optimising test interval for safety systems with respect to material degradation due to ageing.
- Understanding the results of testing, inspection and monitoring of process equipment with respect to degradation mechanisms.
- Understanding the consequences of combining old and new equipment.
- Assessing the effects of subsidence on relevant SSC, such as structure, helideck and free fall lifeboats.

10.4 Further research and development

In the report, the following recommendations for research and development have been found:

1. Initiating an interdisciplinary project on analyses of degradation mechanisms of critical systems, comprising:
   a. Modelling of the main degradation mechanisms, also considering the combined effect of various degradation mechanisms, common cause failures, effect of risk reducing measures and effect of operational conditions.
   b. Development of systems for data collection and use of field experience with degradation failures.

2. Developing a general guideline for design of the LE processes encompassing the entire facility, e.g. by means of a case study.

3. Improving maintenance management systems for ageing and life extension so that all three ageing aspects are being “processed” in parallel, in order to evaluate and improve the operator’s maintenance systems prior to and during life extension. Such management would mean improved awareness and overall knowledge of the SSC on the facility, e.g. combinations of old and new equipment, availability of spare parts, common cause failures, new types of operation and new technology.

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Appendix A: Definitions and abbreviations

A.1: Definitions

This report will apply the following definitions:

Ageing (physical ageing) – General process in which the characteristics of a system, structure or component (SSC) gradually change with time or use, [26].

– Physical phenomenon which involves a modification of the physical and/or chemical characteristics of the material, [51].

– A process of degradation related to the progression of time and/or the use of the facility and the systems related to the facility, [60].

Ageing management – Ensuring the availability of required safety functions with account taken of changes that occur with time and use. This requires addressing both physical ageing of SSC, resulting in *degradation* of their performance characteristics, *obsolescence* of SSC, i.e. their becoming out of date in comparison with current knowledge, standards and regulations, and technology, and *organisational ageing*. ([28], slightly edited)

Availability – The ability of an item (under combined aspects of its reliability, maintainability and maintenance support) to perform its required function at a stated instant of time or over a steted period of time [73].

Best Available Techniques (BAT) – A key principle in the IPPC[3] Directive 96/61/EC defined as follows: "The most effective and advance stage in the development of an activity and its methods of operation, which indicate the practical suitability of particular techniques for providing, in principle, the basis for emission limit values designed to prevent or eliminate or, where that is not practicable, generally to reduce emission and its impact on the environment as a whole." [35].

Ageing effects – Net changes in the characteristics of an SSC that occur with time or use, and are due to ageing mechanisms. For examples of negative effects, see ageing degradation, [26] .

Barrier – Defenses that prevent a vulnerable target from being exposed to hazardous energy in an accident event, [14]

Barrier function – The function the barrier is intended to perform to prevent the realisation of a hazard or limit the hazard by stopping the chain of event, [14].

Barrier system – The technological, human or organisational system that is ensuring that the barrier function is fulfilled, [14].

Common cause failure – Failures of different items resulting form the same direct cause and where these failures are not consequences of each other, [51].

Condition monitoring – Evaluation of the condition and behavior of SSC in service using data form design, inspection and instrumentations, [41] (slightly edited).

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[3] Integrated Pollution Prevention and Control

- The continuous or periodic measurement and interpretation of data to indicate the degraded condition (possible failure) of an item and the need for maintenance, [51].

Criticality analysis – Quantitative analysis of events and faults and the ranking of these in order of the seriousness of their consequences, [51].

Decommissioning – Process of shutting down a platform and removing hazardous materials at the end of its production life, [39].

Degradation – Changing to a lower technical state. Another word used is deterioration. According to [38] *Deterioration* is a process that adversely affects the structural performance, including reliability over time due to

- naturally occurring chemical, physical or biological actions,
- repeated actions such as those causing fatigue,
- normal or severe environmental influences,
- wear due to use, or
- improper operation and maintenance of the structure.

Degradation mechanism – A specific process that gradually changes the characteristics of an SSC with time or use. Examples are curing, wear, fatigue, creep, erosion, microbial fouling, corrosion, embrittlement and chemical or biological reactions, [26].

Design service life – Assumed period for which a structure is to be used for its intended purpose with anticipated maintenance, but without substantial repair being necessary, [39].

Exemption – The authorities' decision to accept a non-conformity relative to regulatory requirements, [60].

Examination – The whole process of verifying conformity with a requirement for integrity, including planning, inspection, evaluation, and/or leak or pressure testing.

Extended service life – assumed period beyond the service life for which a facility is to operate and still obtain an acceptable technical and operational integrity.

Facility – A fixed installation installed on the Norwegian Continental Shelf that is not defined as a mobile installation. Can be a fixed platform, floating platform or pipeline, [60].

Failure – The termination of the ability of an entity to perform a required function, [30], [51]. *Ageing failure* is a failure whose probability of occurrence increases with the passage of time (independent of the operating time), [51].

Failure mode – The effect by which a failure is observed, [30].

Failure cause – The circumstances during design, manufacture or use, which have led to a failure, [30].

Failure mechanism – The physical, chemical or other process which has led to a failure, [51]; (ref. degradation mechanism)

Fault – The state of an item characterised by its inability to perform a required function, excluding the inability during preventive maintenance or other planned actions, or due to lack of external resources, [51].

Fitness for service (FFS) assessment – Quantitative or qualitative engineering evaluation of the structural integrity of a component containing a flaw or damage, carried out to a published procedure. Also known as “Fitness for Purpose (FFP) Assessment” or “Engineering Critical Assessment”, [23].

Gap – An identified difference between systems in place and facilities design and a recognised and accepted standard e.g. the standards in and referre to in the Facilities Regulations, [60].

Indicator of ageing - A sign or evidence that some damage has already or is about to occur, and can be thought of as symptoms of ageing damage.

Influencing parameter – Environmental influence – Mechanical, physical, chemical or biological influence which may cause degradation of the materials constituting a structure, which in turn may affect its serviceability and safety in an unfavourable way, [43].

Inspection – Conformity evaluation by observation and judgement accompanied, as appropriate, by measurement, testing or gauging to verify that the execution is in accordance with the project work specification, i.e. all information and technical requirements necessary for the execution of the works, includes documents and drawings, etc. as well as references to relevant regulations, specifications, etc. [41].

- A careful and critical scrutiny of the item of equipment for determining its condition, the purpose of which is to discover flaws that can give rise to danger. Inspections can include non-destructive testing, as well as visual surveys, replication of a surface, and materials sampling to determine the physical and metallurgical condition of the equipment.
- Check for conformity by measuring, observing, testing or gauging the relevant characteristics of an item, [51].

Life enhancement – The methods/process to obtain an acceptable technical and operational integrity throughout the extended service life.

Life extension – The period of extended lifetime of a facility.

Life extension assessment / LE process – The process to evaluate if life extension of a facility and its SSC is acceptable.

Maintainability – Ability of an item under given conditions of use, to be retained in, or restored to, a state in which it can perform a required function, when maintenance is performed under given conditions and using stated procedures and resources, [51].

Maintenance – Set of activities performed during the working life of the structure in order to enable it to fulfil the requirements for reliability, [40].

– Combination of all technical, administrative and managerial actions during the life cycle of an item[4] intended to retain it in, or restore it to, a state which it can perform the required function, [51].

Mitigation – Plan covering the need for upgrading (repair/replacement), monitoring, inspection and testing.

[4] Any part, component, device, subsystem, functional unit, equipment or system that can be individually considered.

Monitoring – Frequent or continuous, normally long-term, observation or measurement of structural conditions or actions, [38].

– Activity, performed either manually or automatically, intended to observe the actual state of an item, [51].

Non-conformity – An identified difference between the physical condition and/or standard on the facility and the requirements in the applicable regulations, [60].

Obsolescence – SSC becoming out of date in comparison with current knowledge, standards, technology and needs, [28] (slightly edited).

Redundancy – The existence of more than one mean at a given instant of time for performing a required function (based on [51]).

Reliability – Ability of an item to perform a required function under given conditions for a given time interval, [51].

Repair – Activities performed to preserve or to restore the function of a structure that fall outside the definition of maintenance, [40].
– Physical action taken to restore the required function of a faulty item, [51].

Risk factor – Conditions or circumstances that can promote or accelerate degradation, or a lack of control (not necessarily sufficient for ageing to occur), [23].

Risk Based Inspection (RBI) – A methodology which aims at establishing an inspection programme based on the aspects of probability and consequence of a failure, [42].

Robustness – Ability of a structure to withstand events with a reasonable likelihood[5] of occurring without being damaged to an extent disproportionate to the cause, [40].

Service life extension – See Extended service life.

Structure integrity (structural robustness) – Ability of a structure not to be damaged by events like fire, explosions, impact or consequences of human errors, to an extent disproportionate to the original cause, [43].

Subsea – Structures and equipment for offshore oil and gas production and transportation located below the sea level or on the seabed.

Technical and operational integrity – Ability of the facility and the operational measures, to maintain the safety of the facility and perform intended operations, in all phases of the extended life.

Test – An experiment carried out in order to measure, quantify or classify a characteristic or a property of an item, [30].

Testing:

- *Destructive testing*: An examination by destructive methods used to detect hidden damage, [41].

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[5] We will use *probability* in the present report

- *Non-destructive testing (NDT):* Operation that covers the testing of any material, component or assembly by means that do not affect its ultimate serviceability, [23].
- *Small-scale testing* is proposed to evaluate in-service degradation, [88].
- *Large scale testing* is proposed to evaluate the overall performance of fatigue design rules and to investigate the effects of weld quality, [88].
- *Compliance test*: Test used to show whether or not a characteristic or a property of an item complies with the stated specification, [51].

Topsides – Structures and equipment placed on a supporting structure (fixed or floating) to provide some or all of a platform's functions.

Useful life – Under given conditions, the time interval beginning at a given instant of time, and ending when the failure intensity becomes unacceptable or when the item is considered non-repairable as a result of a fault, [30].

Well integrity – An applicaton of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well, [30].

A.2: Abbreviations and Acronyms

Below is a list of abbreviations and acronyms used in this report.

AC	-	Acceptance Criteria
AISI	-	American Iron and Steel Institute
ALARP	-	As Low As Reasonable Practicable
AM	-	Ageing Management
AMP	-	Ageing Management Programme
API	-	American Petroleum Institute
ASME	-	American Society of Mechanical Engineers
BAT	-	Best Available Technique
BOP	-	Blowout Preventer
BS	-	British Standard
BWR	-	Boiling Water Reactor
CBM	-	Condition-Based Maintenance
CI	-	Condition Indicators
CUI	-	Corrosion Under Insulation
CM	-	Condition Monitoring
CM	-	Corrective Maintenance
CP	-	Cathodic Protection
CoF	-	Consequence of Failure
DOE	-	U.S. Department of Energy
DNV	-	Det norske Veritas
D&W	-	Drilling and Well
EAOL	-	Extended Anticipated Operating Life
ECA	-	Engineering Critical Assessment
EER	-	Emergency, Escape and Rescue
EN	-	European Norm
EPRI	-	Electric Power Research Institute
ESD	-	Emergency Shut Down
ESV	-	Emergency Shut down Valve
FAC	-	Flow-Accelerated Corrosion

FBE	-	Fusion Bonded Epoxy
FD	-	Fire Detector
FDF	-	Fatigue Design Factor
FFE	-	Fire Fighting Equipment
FFS	-	Fitness-For-Service
F&G	-	Fire and Gas
FGD	-	Fire and Gas Detection
FUI	-	Fatigue Utilisation Index
GALL	-	Generic Ageing Lessons Learned
GD	-	Gas Detector
HC	-	Hydro Carbon
HE	-	Hydrogen Embrittlement
HIC	-	Hydrogen Induced Cracking
HIPPS	-	High Integrity Pressure Protection System
HPCS	-	High Pressure Core Spray (BWR system)
HPI	-	High Pressure Injection (BWR system)
HPIC	-	Hydrogen Pressure Induced Cracking
HSE	-	Health and Safety Executive (UK)
HSE	-	Health, Safety and Working Environment
HVAC	-	Heating, Ventilation and Air Condition
IAEA	-	International Atomic Energy Agency
IASCC	-	Irradiation Assisted Stress Corrosion Cracking
IGSCC	-	Intergranular Stress Corrosion Cracking
I&M	-	Inspection and Monitoring
IMR	-	Inspection, Maintenance and Repair
IMS	-	Integrity Management System
INEL	-	Idaho National Engineering Laboratory
I/O	-	Input/Output
IOR	-	Increased Oil Recovery
IPPC	-	Integrated Pollution Prevention and Control
ISO	-	International Organisation for Standardisation
KPI	-	Key Performance Indicator
LC	-	Life Cycle
LE	-	Life Extension
LER	-	Licensee Event Report
LTSR	-	Long Term Safety Review
MCC	-	Motor Control Center (or Molded-Case Circuit) (Nuclear)
MCP	-	Manual Call Point
MFA	-	Manual Fire Alarm
MIC	-	Microbiologically Influenced Corrosion
MoC	-	Management of Change
MTO	-	Man – Technology – Organisation
NCS	-	Norwegian Continental Shelf
NEI	-	Nuclear Energy Institute
NDT	-	Non-Destructive Testing
NII	-	Non-Invasive Inspection
NPD	-	Norwegian Petroleum Directorate
NPP	-	Nuclear Power Plant
NPRDS	-	Nuclear Plant Reliability Data System
NS	-	Norsk Standard (Norwegian Standard)
OLF	-	Oljeindustriens landsforening (The Norwegian Oil Industry Association)
OMAE	-	Offshore Mechanics and Arctic Engineering

OREDA	-	Offshore Reliability Data
P&A	-	Plug and Abandon
PARLOC	-	Pipeline and Riser Loss of Containment
PAS	-	Public Address systems
PC	-	Process Control
PFD	-	Probability of Failure on Demand
PFP	-	Passive Fire Protection
PIMS	-	Pipeline Integrity Management System
PM	-	Preventive maintenance
PoF	-	Probability of Failure
PSA	-	Petroleum Safety Authority, Norway
PSD	-	Process Shut-Down
PSV	-	Pressure (Safety) Relief Valve
PT	-	Pressure Transmitter
PVDF	-	Poly Vinyl Di Fluoride
R	-	Risk
RAC	-	Risk Acceptance Criteria
RBI	-	Risk Based Inspection
R&D	-	Research and Development
ROV	-	Remotely Operated Vehicle
RP	-	Recommended Practices
SIM	-	Structural Integrity Management
SCC	-	Stress Corrosion Cracking
SCE	-	Safety Critical Element
SCS	-	Steel Catenary Riser
SCSSV	-	Surface Controlled Subsurface Safety Valve
SOHIC	-	Stress Oriented Hydrogen Induced Cracking
SSC	-	Systems, Structure, Components
SRB	-	Sulphate Reducing Bacteria
TPD	-	Third Party Damage
TST	-	Technical Safety Systems
TWI	-	The Welding Institute, UK
UiS	-	University in Stavanger, Norway
UKOOA	-	United Kingdom Offshore Operators Association
VIV	-	Vortex Induced Vibrations
WC	-	Tungsten Carbide
WH	-	Wellhead
XT	-	X-mas Tree

Appendix B: Literature review of ageing and life extension

B.1: Ageing management

Ageing equipment is equipment for which there is evidence or probability of significant deterioration and damage taking place since new, or for which there is insufficient information and knowledge available to know the extent to which this possibility exists [23].

In general there are limited experiences from ageing and life extension of offshore facilities. There are a number of facilities now reaching an age of 20-30 years. None of the facilities that have been given permission for an extended operation period have ended the period permitted (at least on the NCS). There are no common approaches in addressing LE among the reviewed documents

Ageing is often referred to as *the general process in which characteristics of SSC (Systems, Structures or Components) gradually changes with time or use*. This definition focuses on technical "durability" and is also most often referred to in the literature. However, ageing could also be related to getting "old and outdated"; the word "obsolescence" is then often used. That is, ageing may be triggered by other technological, or even social or economic factors: performance inferior to that of new and more modern equipment; concepts, design or materials surpassed by new technologies; incompatibility or obsolescence of the control and command system and software; lack of spare parts; profitability limit reached; more stringent regulations; stricter safety margins and finally, evolution in the operating profile of facilities and in environmental regulations, (see Section 1.1 of ESReDA, 2006), [15].

The ESReDA book, *Ageing of Components and Systems*, ([15]) states that there are two perceptions of ageing:

1. A "reliability-based" concept, implying that *either* a failure (loss of function) has occurred, *or* the unit can operate (but perhaps degraded); or
2. A "physical ageing" concept, which corresponds to the slow, continuous process of degradation of the equipments properties and functions.

In the first case, the focus is on the life time (distribution), failure rates, etc. Table 31 from (ESReDA, 2006) compares these two concepts. We comment to this table that "influencing covariables" (or *covariates*) which is mentioned under "indicators sought" are perhaps not indicators, but they are actually equally relevant for modelling of the reliability-oriented and physically-oriented approaches.

Table 31: The two concepts of ageing (ESReDA, 2006), [15]

Concept	Reliability-oriented	Physically-oriented
Components concerned	Essentially active components	Essentially passive components
Degradation mechanisms	Many	Often only one
Failure modes	Many	Often only one (that can be prevented thanks to monitoring)
Speed of appearance of ageing	Relatively rapid, sometimes sudden	Slow, a continuous process
Modelling	Probabilistic (Attempt to find a lifetime law using a sample of observed failures)	▪ Physical, if knowledge is sufficient, as the single degradation mechanism is known ▪ Or statistical, based on degradation data observed at more or less regular time intervals
Principal data (input data)	Failures (loss of function)	Degradations (e.g. test data, wear-out data, inspection data)
Other data used	Survival data (right censored) Expert assessments	When possible, physical data. Expert assessments Analogous feedback
Indicators sought	Failure rate / intensity Probability of failure Mean lifetime	Failure rate/intensity Remaining life Influencing covariables
Domain	Reliability and maintenance, RCM methodology	Physical probabilistic methodologies, Condition based maintenance

There are number of ways to illustrate ageing management in the literature; some are on component level while others are on plant level, some focus on the sequence of steps in the management while others are method focused.

IAEA, [27], differentiates between three steps of ageing management, (also see [77]):

1) Understanding ageing
2) Monitoring ageing
3) Mitigating ageing.

The different steps of ageing management are outlined and illustrated in Figure 27.

The operators' analyses and evaluations shall demonstrate an understanding of how time and ageing processes will affect HSE, technical integrity, overall facility robustness and resource exploitation and identify measures required to mitigate the impact of time and ageing processes [56].

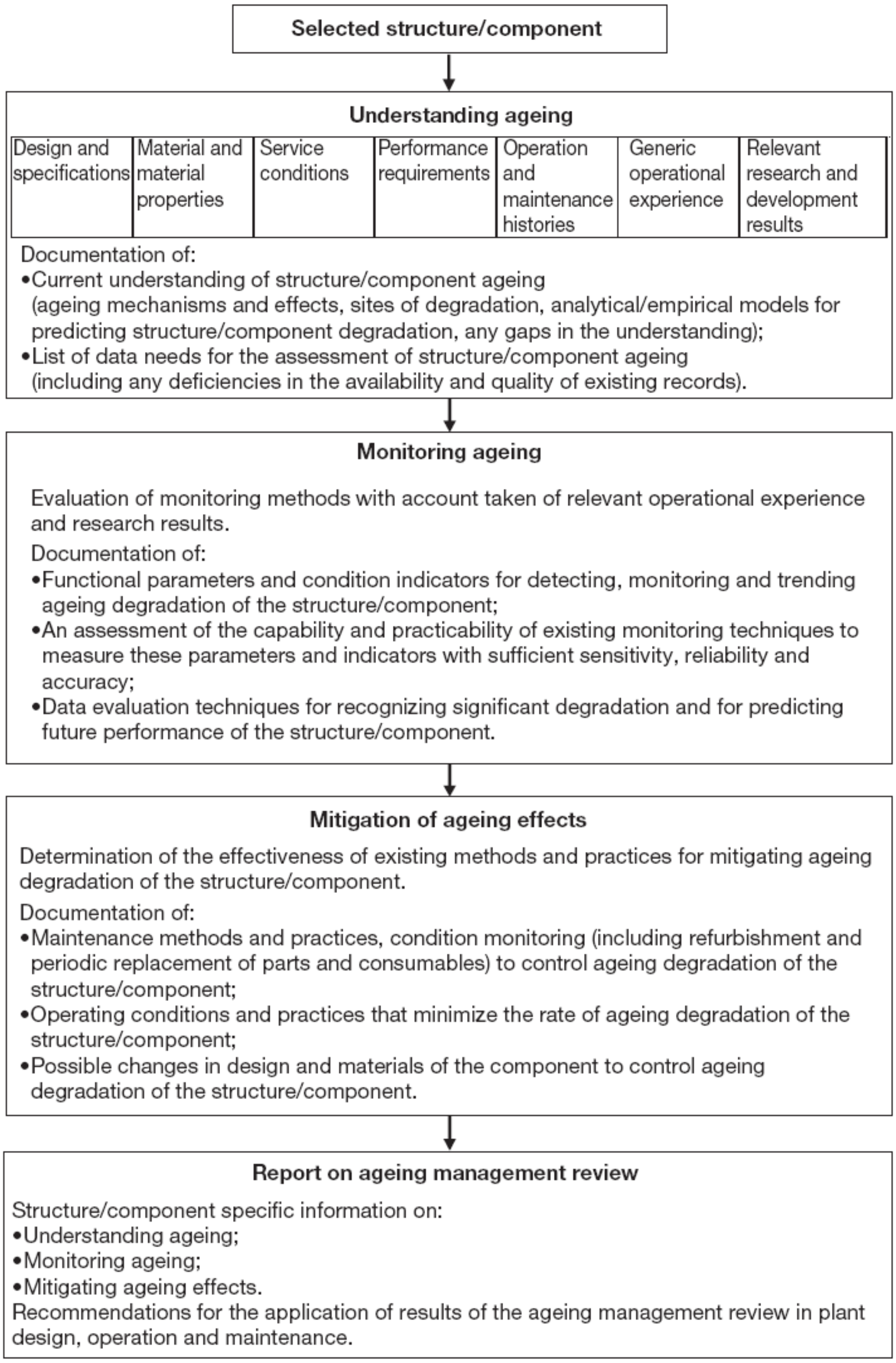

Figure 27: Illustration of the review of the management of ageing, [28]

IAEA, [28], also gives a systematic approach to managing ageing, shown in Figure 28, consisting of a cycle with the following steps:

1) Development and optimisation of activities for ageing management of SSC
2) Operation/use of SSC
3) Inspection, monitoring and assessment of SSC
4) Maintenance of SSC.

Understanding ageing of the SSC is a prerequisite for managing ageing, i.e. in each of the above steps.

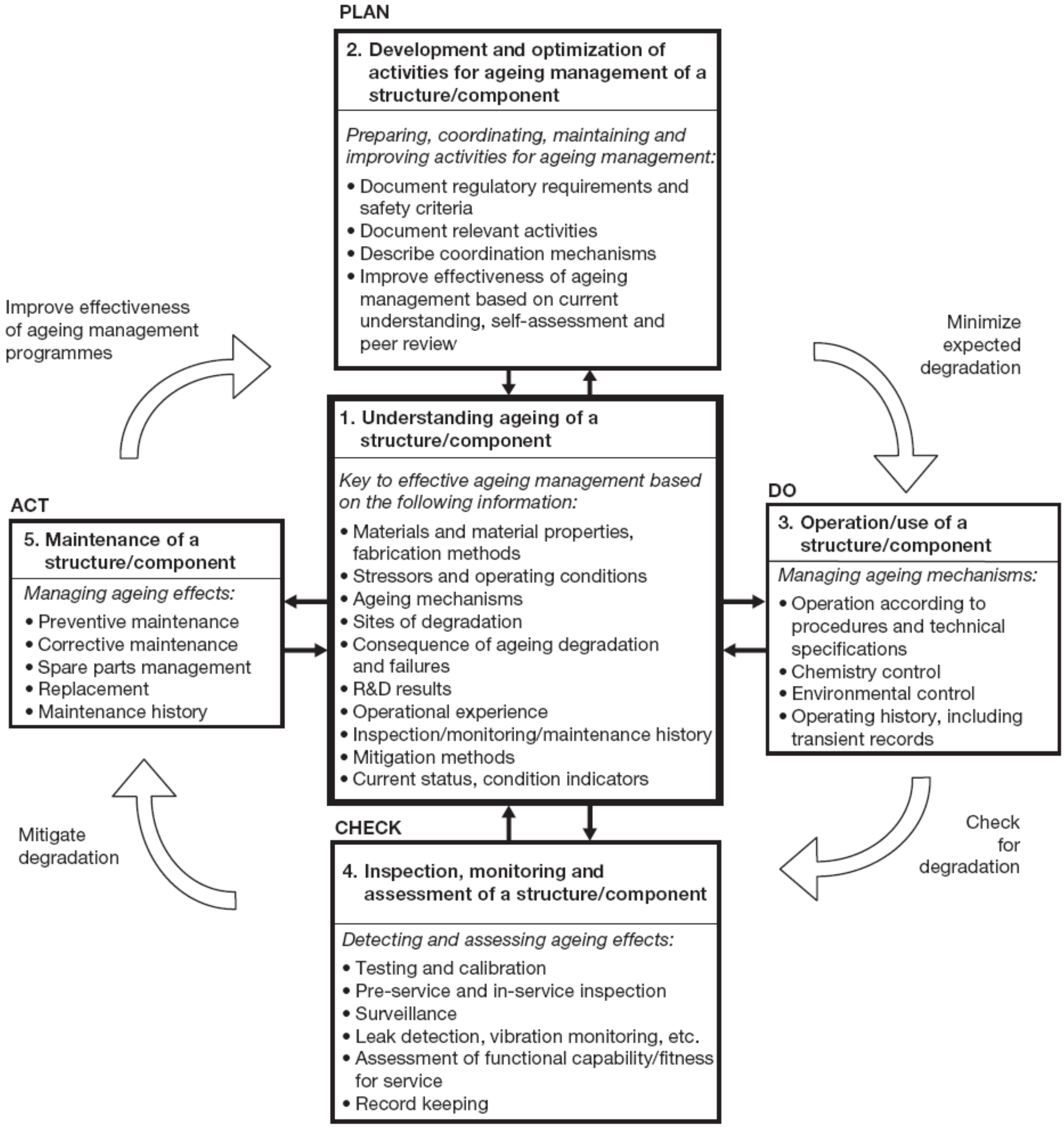

Figure 28: Systematic approach to managing ageing, [28]

According to Chockie, [6] there are four general types of ageing management programs:

- **Prevention –** to preclude certain levels of ageing degradation from occurring (e.g., coating programs to prevent external corrosion of a tank)
- **Mitigation –** to reduce or slow ageing effects (e.g. chemistry programs to mitigate internal corrosion of piping)
- **Condition monitoring –** to inspect for the presence of and extent of ageing effects (e.g., visual inspection of concrete structures for cracking and ultrasonic measurement of pipe wall for erosion-corrosion induced wall thinning)
- **Performance monitoring –** to test the ability to perform its function (e.g., heat balances on heat exchangers for the heat transfer intended function of the tubes).

Further, [6] describes the following ageing management "elements", see [77] for details:

- Preventive maintenance
- Parameters monitored or inspected
- Detection of ageing effects
- Monitoring and trending
- Acceptance criteria
- Corrective maintenance
- Confirmation processes
- Operation experience.

Active and passive SSC
Table 31 allocates active and passive components to the reliability-oriented and the physically-oriented ageing approach, respectively. Actually, the nuclear industry highlights the distinction between *active* and *passive* components, and has a focus on passive, long-lived SSC in order to reduce the ageing process to manageable proportions.

The age related degradation of active components has the characteristic of affecting their functional performance during normal operation. The effect may be immediate (e.g. failure of power supply) or gradual (e.g. progressive increased valve closure time). Here the effect of gradual degradation of an active component is often detectable, and this allows time to take action before the components actually fails to perform its function. In addition, active components are often subject to maintenance (testing and replacement).

On the other hand age related degradation of passive components may not be as easily detectable as for the active components, since the SSC appears to function normally until the moment when it fails. Further, passive components are maintained (inspected) less frequently than active components, [87].

The definition of active and passive components may be adjusted when applied to offshore installations. Equipment that is kept in standby or is used or tested infrequently, such as the fire deluge systems, the ESD valves or the HVAC dampers, may - although in principle active - be treated as passive. In total, this simple distinction between active and passive components does not seem sufficient to decide how main risks due to ageing of offshore equipment shall be assessed, but it gives a first rough classification, [87].

B.2: Life extension assessment

The reviewed literature includes discussions on life extension assessments (or fitness-for-service assessments), i.e. not being system specific, but rather apply for a whole facility. Some literature related to the "LE process" is shortly reviewed in this section. This also includes maintenance management programmes that can be modified to a part of an LE assessment.

In particular when considering to extend the life of existing structures, it is of great importance to evaluate whether there is a possibility for failure modes of the existing structure that was not considered in the design phase [88].

The LE process shall in total verify that the failure rate estimated at the end of design life will not be reached until the end of the extended life. Probably additional mitigation measures must be put into effect in order to keep the failure rate below the acceptance criteria throughout the extended lifetime.

NORSOK Z-008, [51], is applicable for preparation and optimisation of maintenance programs for plant systems and equipment including topside systems and subsea production systems (structures, risers and pipelines excluded). A process diagram to establish a maintenance program is given in Chapter 7 in the standard, and is shown in Figure 29. This breakdown is here introduced to handle the maintenance and to come up with a maintenance program during operation, but it might also serve as a tool in the LE process.

Note that Z-008 also suggests a system classification according to criticality (consequence).

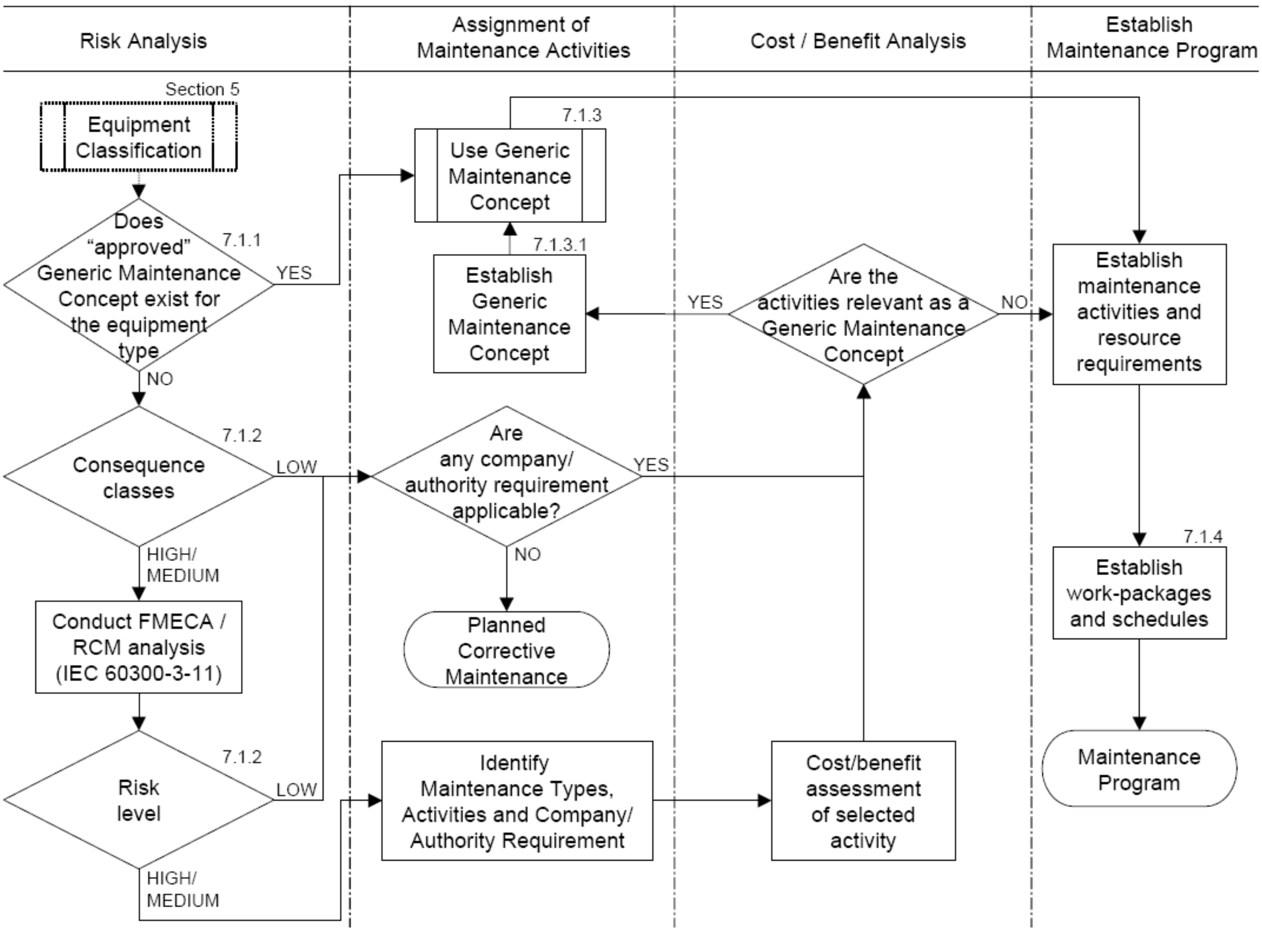

Figure 29: Process diagram, establishing maintenance program (NORSOK Z-008, [51])

Long Term Safety Review (LTSR)
A Long Term Safety Review (LTSR) of structural safety critical elements has been recommended when LE is envisaged. This could be a part of a future safety case submission. The stages in the LTSR include, [68]:

- Defining the end of the anticipated operating life (based on the notional design life or 20 years as a minimum).
- Defining the target extended anticipated operating life (EAOL) (based on field life and other factors)
- Undertake a LTSR to confirm continued integrity of the structural safety critical elements (SCEs) to the end of the EAOL, taking account of relevant hazards and threats to structural

integrity. The LTSR should also establish the current configuration, materials properties and physical condition of the structure, through assessment of past records and recent testing and inspection data. A further requirement for the LTSR is to carry out a full structural assessment of the structural SCEs, based on best available data and checking against modern codes and standards. A redundancy analysis is also recommended to demonstrate that in the event of reasonably foreseeable damage to the facility sufficient structural integrity would remain to enable action to be taken to safeguard the health and safety of personnel on board.

- Identify any shortfall in the long term integrity of the structural SCEs.
- Implement any improvements required to maintain the integrity of the facility over the EAOL.
- If improvements are unable to extend the operating life then a revision to the anticipated operating life is required.

OLF checklist for LE process
OLF has presented a checklist of "elements that should be considered during the assessments of continued safe drilling and well operations", [59]. However, many of the issues listed here are relevant for *all* systems (the overall facility) when life extension is considered. The drilling and well specific issues of [59] are presented in Section 6.2.2, while the general issues are listed below. These are highly relevant for the general LE process, (cf. Chapter 2).

First, [59] provides some *general considerations and requirements*, (here slightly edited, and formulated as *not* being well/drilling specific):

1. Status on the system, with description of current service life, technical condition, main capabilities, and conformity to current regulations/exemptions. Relevant incidents and KPI records expected to be followed up.
2. Main degradation mechanisms and corresponding control measures relating to "safety critical equipment".
3. Technical integrity situation and possible changes in the related risk-picture (locally and towards other parts of the installation)
4. Future activity level and modification plans
5. Future capabilities required to monitor, access, operate and maintain the SSC during the extended lifetime
6. Condition of utility systems to support future activities.

The issues 1, 4, 5 and 6 on the above list point out important (operational) information of the SSC, which must be collected in the LE process. Issue 2 points to the need of investigating degradation mechanisms of critical equipment, and issue 3 to the need of risk analyses, (in particular to investigate "changes of risk").

Next, [59] lists some *recommendations* related to the LE process:

- Start the development of the extension application early, and include personnel with sufficient competence within the respectively systems.
- Proper verifications, realistic plans and committed execution should be emphasised.
- Know how to adhere to the NORSOK standards of relevance for the respectively systems.
- Ensure that the life extension assessment is up to date.

Contents of application for LE
[87] suggests that the typical contents of the application for consent to LE should include (but is not restricted to) the following points, see [77]:

- Identify hazards and the barrier systems available to prevent or mitigate these hazards
- Identify integrity/functionality of equipment required for the barrier systems to perform their function
- Assess design and current performance
- Assess future performance
- Identify asset management plan (maintenance schedules, for monitoring, testing, repairs, replacements) that will ensure continue performance of barrier systems.
- State management structure, competencies and number of asset specific and support workforce that would be employed to manage and maintain the ageing facility during the LE period.
- Assess the period of LE that would be acceptable to regulator
- Considerations of uncertainty (ref. below).

The OLF Guideline No. 122, [60], outlines "a proposal for the preparation of the application of renewed consent required prior to use of a facility exceeding the consent period, which may coincide with the initial design life". This Guideline is intended to be compatible with the relevant PSA and NPD guidance notes for their respective regulations, and it includes the following topics:

- Involvements of interested parties / Responsibilities
- Contents of the Consent Application and Description of the Process including
    - A "suggested contents list for an application for consent" (Appendix 2)
    - Schematics of the application process (Appendix 3)
- Use of the facilities (in the period that is applied for)
- Timing for the application; (application for consent for LE shall be submitted one year before the current lifetime expires)
- Period for application
- Analyses and evaluations to be carried out by operator
- HSE and Technical Integrity. The following analyses and evaluations shall be carried out (to demonstrate a satisfactory standard for HSE and technical integrity):
    - Structural Integrity
    - Technical Integrity and Conditions
    - Gap analysis against Facilities Regulations
    - Changes to Operational Conditions
    - Maintenance (inspection)
    - Barriers
    - Wells
    - Drilling systems
    - Pipelines
    - Verification of 'as built' documentation (provide a verification of the physical match between the facilities and 'as built' documentation)
    - Risk Assessment; (carry out analyses and evaluations to verify that risk levels are within acceptable limits in the period that has been applied for)
    - Emergency Preparedness and Response
    - Environment; (show how the impact on the environment can be improved in the period applied for)
    - Working Environment
    - Compliance with the regulations

  - Technology; (provide any evaluations of the application of technology and techniques that is new to the facilities and can be used to improve the HSE standards)
  - Organisation; (provide an analysis of how the experience, competence and knowledge can be retained at a satisfactory level in the period that is applied for)
  - Management of Change (MoC); (describe the process for MoC; describing both technical and organisational change)
  - Exemptions; (exemptions that have been identified by operator and granted by authorities must be in the application for consent)
- Resource Exploitation
- Conditions for Consent; (work should include plans for the implementation of technical and organisational improvements identified in the application process)
- Decision Process; (summarise alternatives for future use of the facilities and provide an overview of major decisions that have been taken with regard to the LE)
- Verification and Approval
- Experience Transfer; various examples related to real cases are given in Appendix 5; (operator should ensure that experience on LE from other installations and operating areas is applied to analyses and evaluations carried out)
- Implementation
- System and conditions that should be evaluated, (Appendix 4)
- Overview of Information Duty Requirements, (Appendix 7).

B.3: Maintenance management

Maintenance management is illustrated as a superior process where products are produced with low HSE risks and high production assurance. The basic model proposed as industry best practice is shown in Figure 30, based on The Petroleum Safety Authority Norway (PSA) “Basisstudie” from 1998.

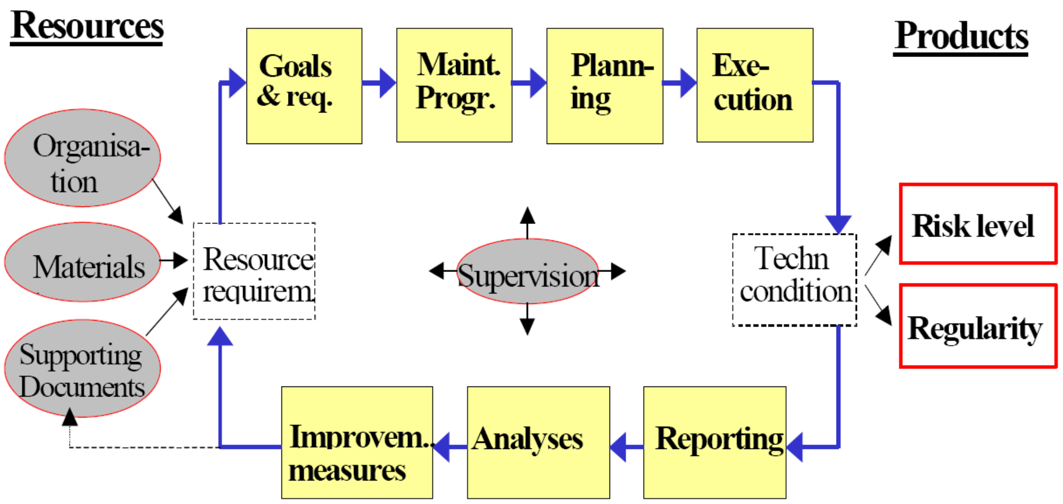

Figure 30: Maintenance management process, [57]

Before entering a life extension period an update of the existing maintenance program is necessary for a set of functions within a system.

For instance, a function previous identified in consequence “low” must now be classified in consequence “medium” due to increased probability of leakage and pollution. In addition, the access to spare parts may become more restricted as equipment ages, and the identification of need for spare parts must be evaluated based on the new maintenance program.

Beside that, the maintenance control model may change when applied to the LE process of ageing facilities. As for today, it is not proven that the maintenance control model shown in Figure 30 is insufficient for covering aspects in an LE. In the report "Maintenance for aging installations – a review" (only available in Norwegian, [77]) a suggestion for an expanded maintenance management model is presented. Among other elements, the expanded model has a higher focus on the use of data/experience and indicators for monitoring purpose.

[4] points out that the difficulty comes in selecting the correct maintenance tactic. From a technical viewpoint, you need to understand how the failure happened and if there was any way you could prevented it. The following tips about how equipment should be maintained are given:

- Failure is not usually related directly to age or use
- Failure is not easily predicted, so restorative or replacement maintenance based on time or use will not normally help to improve the failure odds
- Major overhauls can be a bad idea because you end up at a higher failure probability in the most dominant patterns
- Age-related component replacements may be too costly for the same reason
- Which failure pattern you choose should follow a careful scrutiny of the data
- Unless the equipment comes into direct contact with the product or a processed material (like steam or component raw materials in pipes), or unless it is a simple device, age probably will have little impact on whether it fails. Therefore, condition-based maintenance is the most effective.
- Knowing the failure pattern does not necessarily tell you what maintenance tactic to use.

B.3.1: Maintenance terminology

Figure 32 illustrates the maintenance terminology and relations between preventive maintenance, condition based maintenance, etc. from NS-EN 13306, [51].

Preventive maintenance

Preventive maintenance (PM) is defined in NORSOK Z-008 ([51]) as *maintenance carried out at predetermined intervals or according to prescribed criteria and intended to reduce the probability of failure or the degradation of the function of an item.* PM seeks to reduce the probability of failure. It may involve inspection, adjustments, lubrication, parts replacement, calibration, and repair of items that are beginning to wear out.

PM and optimisation of intervals should according to [51] be based on:

- Consequences of function failures
- Probability of function failures
- Functional redundancy
- Detectability of failure and failure mechanisms, including the time available to make necessary mitigation to avoid critical function faults
- Required availability of safety critical functions

In [46] it is stated that the frequency of PM should not be considered based on neither the failure frequency nor the criticality of the item. Instead, as failures are occurring during the final stages of degradation, it should be based on the PF-curve which shows how a failure starts and deteriorates to the point at which it can be detected (the possible failure point "P"). Thereafter, if it is not detected and suitable action taken, it continues to deteriorate until it fails ("F"). The amount of time which elapse between the point where a possible failure occurs and the pint where it deteriorates into a functional failure is known as the P-F interval. Unless there is a good reason to do otherwise, it is usually sufficient to select a checking interval equal to half the P-F interval. However, the uncertainty and the time to respond on the possible failure must be taken into account. A PF curve is illustrated in Figure 31. It is a prerequisite that we are able to detect when the degradation has passed the point “P” and that we know the length of the P-F interval.

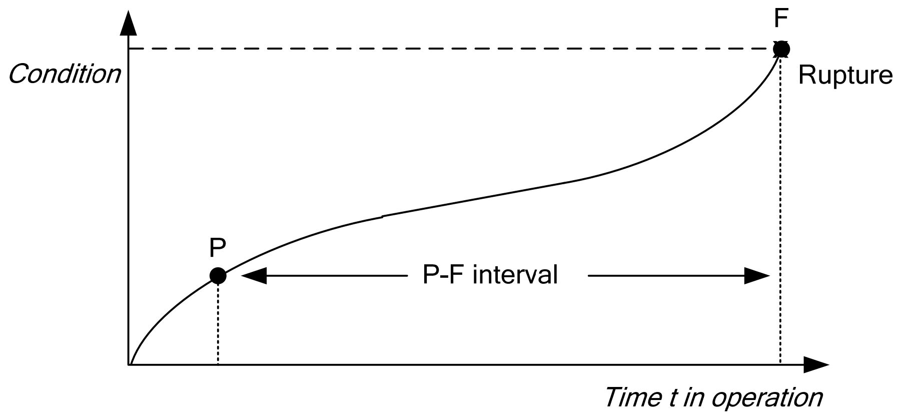

Figure 31: Illustration of PF interval

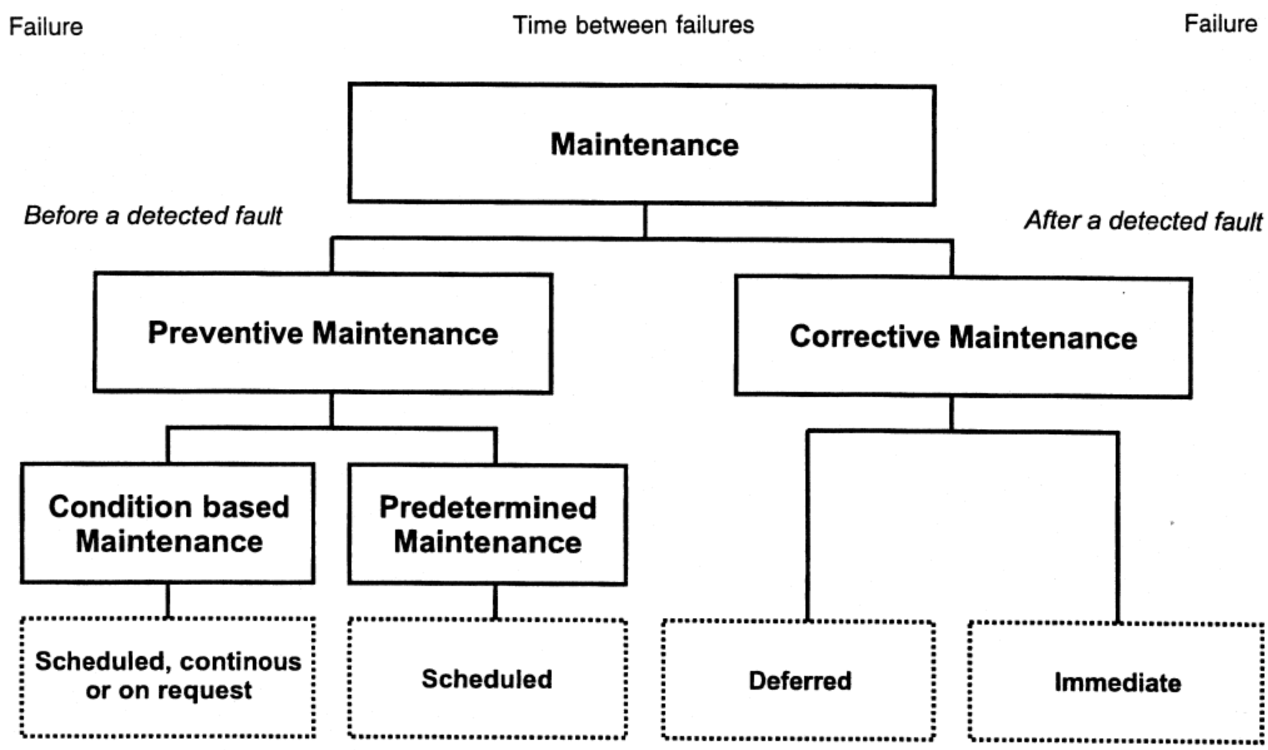

Figure 32: Maintenance terminology – Overview [32]

The two types of preventive maintenance are, [32]:

1. *Predetermined maintenance*: PM carried out in accordance with established intervals of time or number of units of use but without previous condition investigation (NS-EN

13306). Other analogues term used in the literature are Age-based maintenance [73] and time-based maintenance [23]. Scheduled maintenance is in [51] defined as PM carried out in accordance with an established time schedule or established number of units of use.

2. *Condition-based maintenance* (CBM): PM based on performance and/or parameter monitoring and the subsequent actions. Performance and parameter monitoring may be scheduled, on request or continuous [51]. Another definition of CBM is PM tasks based on measurement of conditions variables, and carried out when the conditional variable approaches/passes a threshold value. The condition variables may be monitored continuously or at regular intervals. The CBM policy requires a monitoring system that can provide measurements of selected variables, and a mathematical model that can predict the behaviour of the system deterioration process. The type of maintenance action and the date of the action are decided based on an analysis of measured values. A decision is often taken when a measurement (of a variable) passes a predefined threshold value. The threshold values make it possible to divide the system state space into different decision areas, where each area represents a specific maintenance decision This type of maintenance policy for systems with an increasing failure rate is often called control limit policy.

[46] proposes an additional type of maintenance that will not fall within the above mentioned categories, that is *detective* maintenance known as functional checks or failure-finding tasks, i.e. tasks designed to check whether something still works. Detective maintenance applies only to hidden or unrevealed failures and therefore affects protective devices only.

Inspection

Inspection is defined as a check for conformity by measuring, observing, testing or gauging the relevant characteristics of an item. Generally inspection can be carried out before, during or after other maintenance activity [51]. Inspection for damage is a key activity for all equipment containing hazardous fluids and/or pressure where the maintenance of containment integrity is vital for continued safe operation. This is particularly so as equipment deteriorates [23].

Risk Based Inspection (RBI) is an approach of inspection planning based on the probability and consequences of failure. RBI has been implemented in the oil industry – manly for process and utility systems and for structures - to optimise the inspection program. Reference is given to two documents for process systems RBI ([2], [9]).

Also note that [23] presents an inspection methodology, ref. Figure 8 of [77].

Monitoring

In [51] *monitoring* is defined as an activity, performed either manually or automatically, intended to observe the actual state of an item. Monitoring is distinguished from inspection in that it is used to evaluate any changes in the parameters of the item with time. Monitoring may be continuous, over time interval or after a given number of operations, and is usually carried out in the operating state.

Modification

In [51] *modification* is defined as a combination of all technical, administrative and managerial actions intended to change the function of an item. It should be noted that by modification is meant neither replacement by an equivalent item nor a maintenance action, but has to do with changing the required function of an item to a new required function. Modification is not part of maintenance.

B.3.2 Maintenance and ageing

Based on the literature review executed in [77], the following key issues within maintenance of ageing facilities are identified:

1. How to detect ageing mechanisms and ageing effects?
2. How to mitigate to ensure that technical integrity is maintained?
3. Is maintenance for better or worse, i.e. does maintenance increase or decrease risk (e.g. due to human factors and advancing technology)?

The above issues are mainly discussed in Chapter 3 (No. 1 and No. 2) and Chapter 4 (No. 3). Some literature findings related to the three issues are given below.

1. Detection

An ageing detection programme may consist of the following, [25]:

- **Inspection and visual examination based on periodic in-service inspection programme** (part of the preventive maintenance programme). Evidence of ageing problems can appear progressively or suddenly. A rigorous inspection and visual *examination* plan based on a periodic in-service inspection programme or on a schedule for all selected components and systems should be established. It may also be part of the preventive maintenance programme.
- **Monitoring**: Ageing effects may be detected by a change in measurable parameters. For example, increase in temperature or pressure may be an indication of the accumulation of corrosion products in the tube of a heat-exchanger and instrument drift may be an indication of electronic component degradation. Periodic condition monitoring provides intermittent information and therefore has more chance of missing rapid deterioration. However, in general, deterioration due to normal ageing mechanisms is relatively slow, and periodic condition monitoring is suitable providing that the intervals are not excessive. Parameters should be measured periodically in a consistent manner and the readings should be compared and assessed. Condition monitoring techniques that are commonly used for machines are vibration, corrosion and oil sampling. Thickness testing and thermography are also useful tools. Performance measures such as flow, pressure, temperature and power draw are the most effective ways of detecting fouling or blockages, [23].
- **Testing:** Many ageing effects cannot be directly measured. Testing may be used to look for signs of deterioration. Regularly scheduled tests should provide comprehensive information to assess ageing effects (e.g. resistance of cable insulation and leakage tests of confinement or containment structures, hardness change in a material due to irradiation). NDT techniques may be useful to identify ageing-related degradation (e.g. ultrasonic thickness measurements to monitor erosion of pipe walls, vibration measurements for degradation for rotating equipment). In some cases a destructive test may be necessary.
- **Performance tests:** Ageing effects can be detected by checking the performance of a system, structure or component (e.g. drifting of set points or deterioration of electronic or mechanical comps of valves and valve actuators may cause changes in the performance of a control system). Examine performance test results for evidence of trends which may indicate ageing problems.

Observe that [41] gives various inspection and condition monitoring requirements on concrete fixed offshore structures, also referred in [77].

While monitoring is the passive collection of data relating to integrity, testing is more a trial of functional performance. Scope and frequency of monitoring and testing may need to increase with extended life, [87].

2. Maintenance and compensating measures
Life extension may require compensating measures and new barriers for facilities in order to maintain a sufficient level of safety. With effective maintenance practices ageing degradation can be managed and operation life can be extended well beyond what was originally planned [6].

When equipment is modified, repaired or when there is a change in the operating conditions, it is necessary to consider the impact of the change on the safety of the equipment and the system, [23].

In the reviewed documents there are many maintenance actions and compensating measures and methods described, most of them technical and equipment specific methods. There are standards (ref. Table 43) and ageing and life extension management describing required and suggestible methods. The prevention of the effects of ageing may be accomplished by, see [25]:

- Surveillance and testing activities to assess degradation of components and system
- A preventive maintenance programme
- Periodic evaluation of operating experience
- Repair and replacement

These and other general methods are briefly described in chapter 4 of [77].

3. For better or worse?
Maintenance factors influencing the risk of the rate of ageing are given in Table 32.

Table 32: Maintenance factors influencing the risk of the rate of ageing ([23], [87])

Accelerating factor	Resultant effects
Poor understanding of equipment by maintenance resource	Increased risk of deterioration or leakage after maintenance
Lack of specification of modification or repair	Increased risk of deterioration of repairs, failure of repairs
Retightening bolting	Shortened life of bolting or gasket
Changes of spares supplier	Risk of reduced integrity from inferior components
Defects or residue after maintenance	Increased risk of corrosion or blockage
Sacrificial anodes not replaced	Ineffective cathodic protection leading to enhanced corrosion rates
Poor control of hydraulic pressure testing	Residues of water may cause corrosion. Deterioration of ‘fragile’ equipment by stressing
Damage to coatings not reinstated	Underlying material exposed to detrimental environment
Equipment modification	Design may be outside original limitations
Operating procedure modifications	Operation may be outside original limits

B.4: System breakdown and screening

System breakdown
In order to achieve effective management of the resources used for maintenance purposed, all equipment should be arranged in a hierarchy according to NORSOK Z-008, [51], given in Figure

33. Redundancy is classified on each level in the technical hierarchy. Common cause failures are not addressed in the standard.

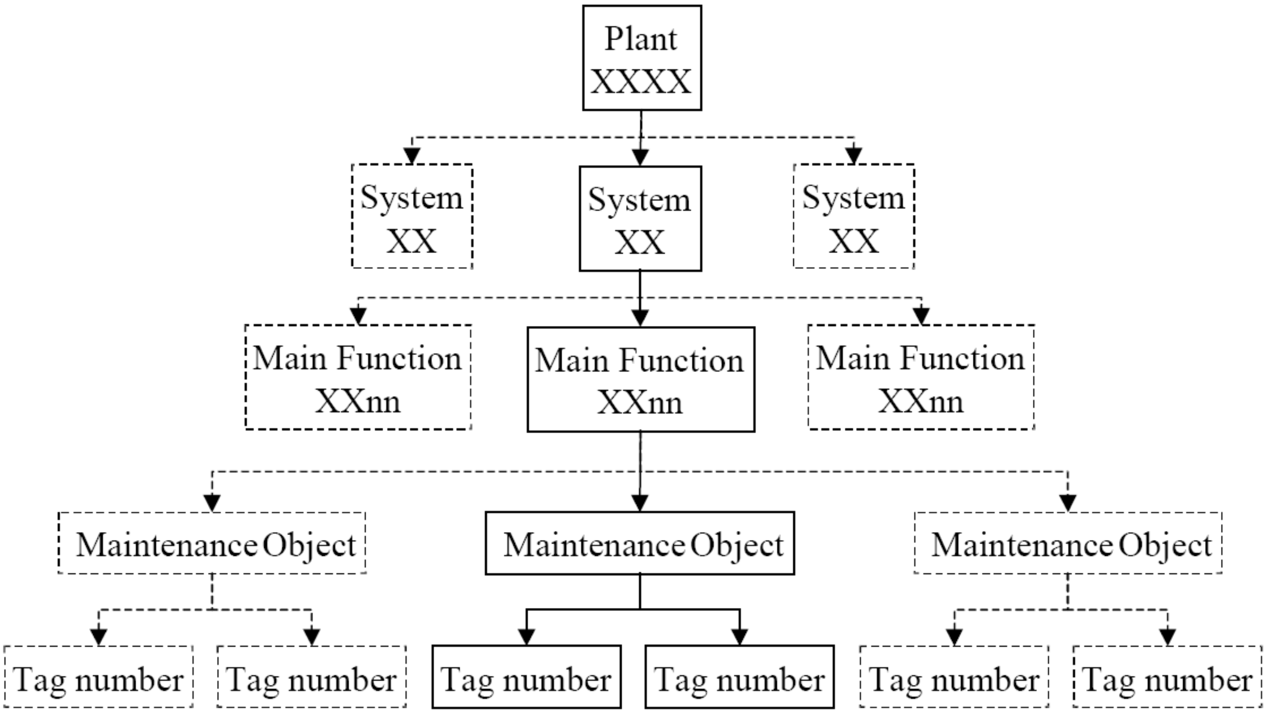

Figure 33: Illustration of equipment hierarchy; NORSOK Z-008, [51]

For the criticality classification of the main functions in [52] the following question is to be asked: *What is the effect on the system/installation if the system/facility if this function does not work or works incorrectly?* The most serious (although realistic) effect of errors/faults is to be described and a percentage reduction in the main function's performance is to be quantified if possible. If the error/fault affects more than one of the areas being assessed, this is also to be described so that it is evident from the text how the effect takes place. In addition, the time form the error/fault occurs until it affects the system/facility should be estimated. A similar assessment can be carried out for sub functions and for systems, subsystems, etc.

According to [56], the following systems should be evaluated (as a minimum):

1. Integrity Management Systems
2. Load Bearing Structure
3. Transport Systems (Pipelines, Risers)
4. Drilling and Well Systems
5. Process systems/ Topside
6. Subsea systems
7. Technical Safety Systems (TST) (EDS, evacuations F&G, PAS)
8. HSE (Accommodation, walkways, stairs, chemicals handling, illumination, MTO, noise and vibration)

Screening

It is neither practicable nor necessary to evaluate and quantify the extent of ageing for all SSC. A systematic approach should therefore be applied to focus on those SSC that can have a negative impact (directly or indirectly) on the safe operation of the facility.

Both in ageing management and maintenance management there are defined methods for system breakdown and component grouping. This is most relevant also for LE, in particular related to screening of SSC, to decide which systems should be subject to detailed analyses.

In the IAEA documents, e.g. [25], ageing managements is described on a component level, and Figure 34 illustrates the suggested grouping of components for ageing management.

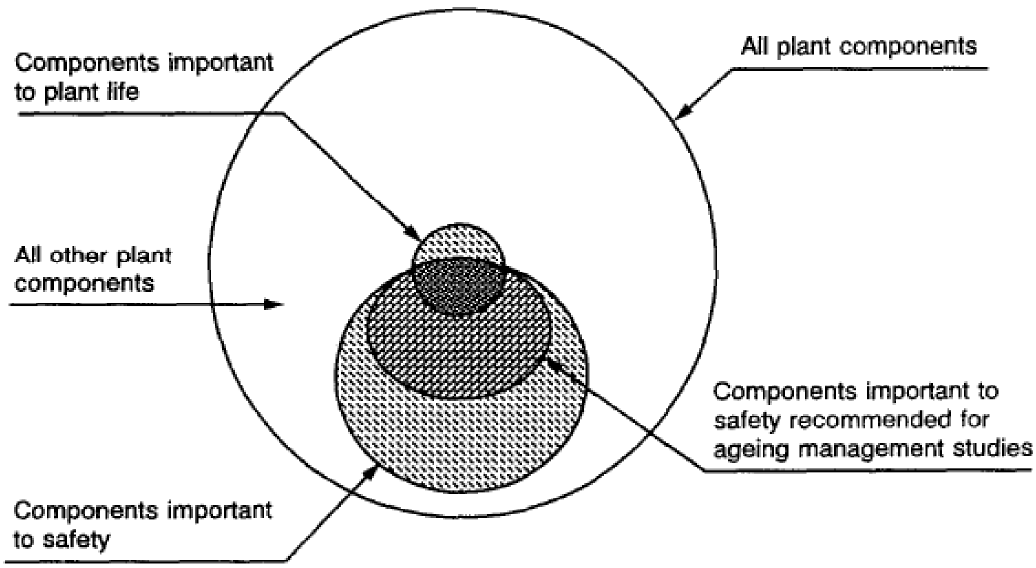

Figure 34: Grouping of components for ageing management [24]

So it is not necessary to evaluate in detail the ageing of all individual components. A systematic screening process can identify a manageable number of components whose ageing should be evaluated. Relevant questions are, see [77] and [28] for details:

1. Does the system or structure contribute to safety?
2. Would component failure result in a loss of system safety function?
3. Does ageing degradation have the possible to cause component failure?
4. Are current operational and maintenance arrangements adequate for timely detection of significant ageing degradation? (cf. condition indicators)

Figure 34 gives an outline of the screening process proposed in [28]. The process consists of question 1-3 above in addition to a final arrange of the selected SSC in generic groups.

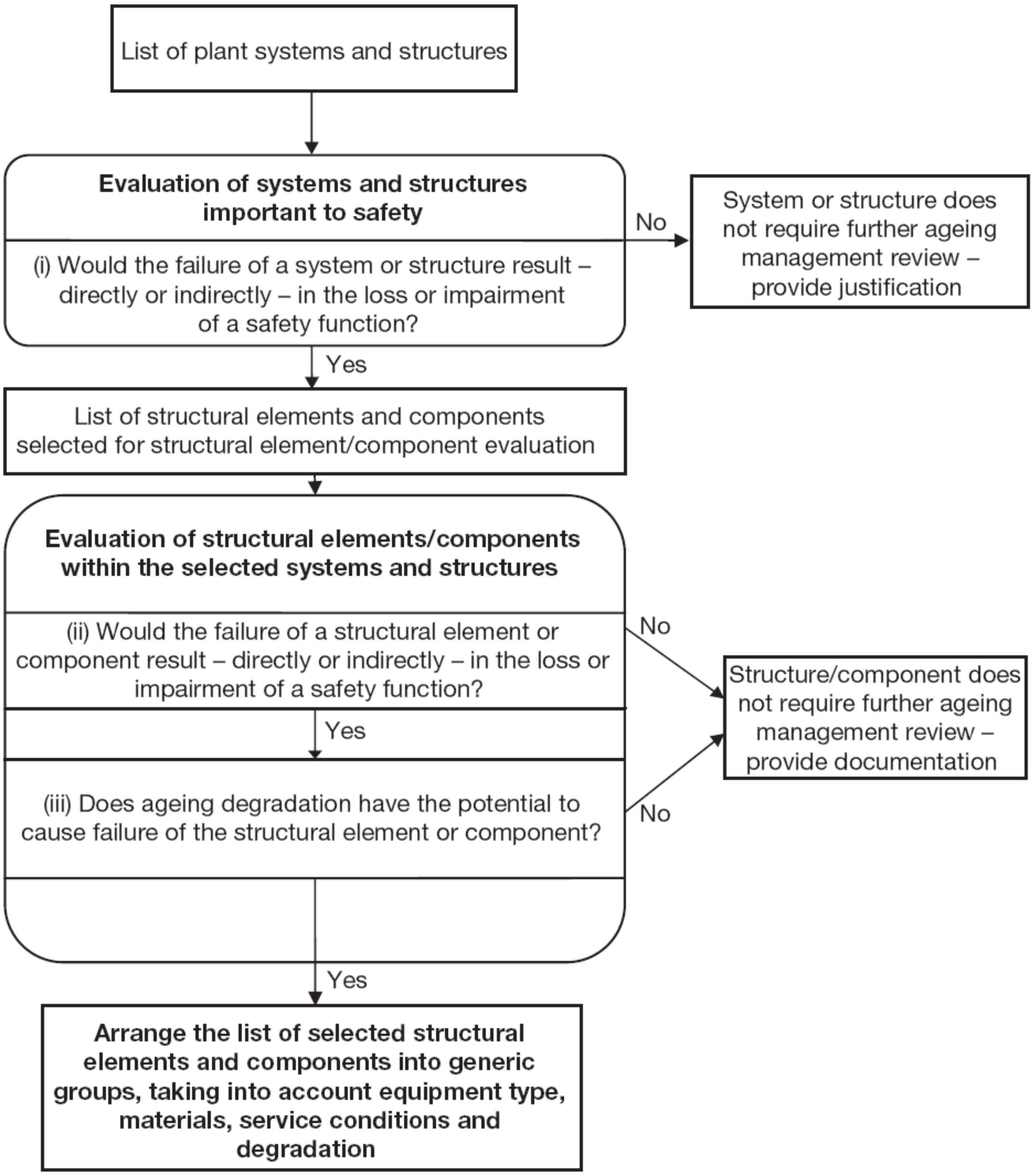

Figure 35: Outline of process for screening SSC for ageing management, [28]

B.5: Physical state of SSC

An important aspect of LE is to identify the physical state (state of degradation) for the various SSC, and to identify the various factors affecting this state, (cf. risk factors and operational conditions). In this respect also indicators for ageing and various compensating measures are important.

B.5.1: Degradation mechanisms and failure modes

Various suggestions for degradations mechanisms found in the literature are referred in Appendices of the literature review [77]. Definitions of degradation mechanisms in the present report are found in Section 3.1.1.

Resulting failure modes are given in Section 3.1.2. Basic concepts of failure analysis as *failure cause*, *failure* (*degradation*) *mechanism* and *failure modes* are sometimes confusing. Note that [72] gives a useful and systematic discussion of these concepts and the interrelation between them, see Figure 36. It is distinguished between component level, item level and system level. Shortly, a failure (degradation) mechanism at component level, can result in a failure, and then the component has a certain failure mode (specifying how the failure appears from outside), this will effect the item level and can be the failure cause to a failure at this level, etc.

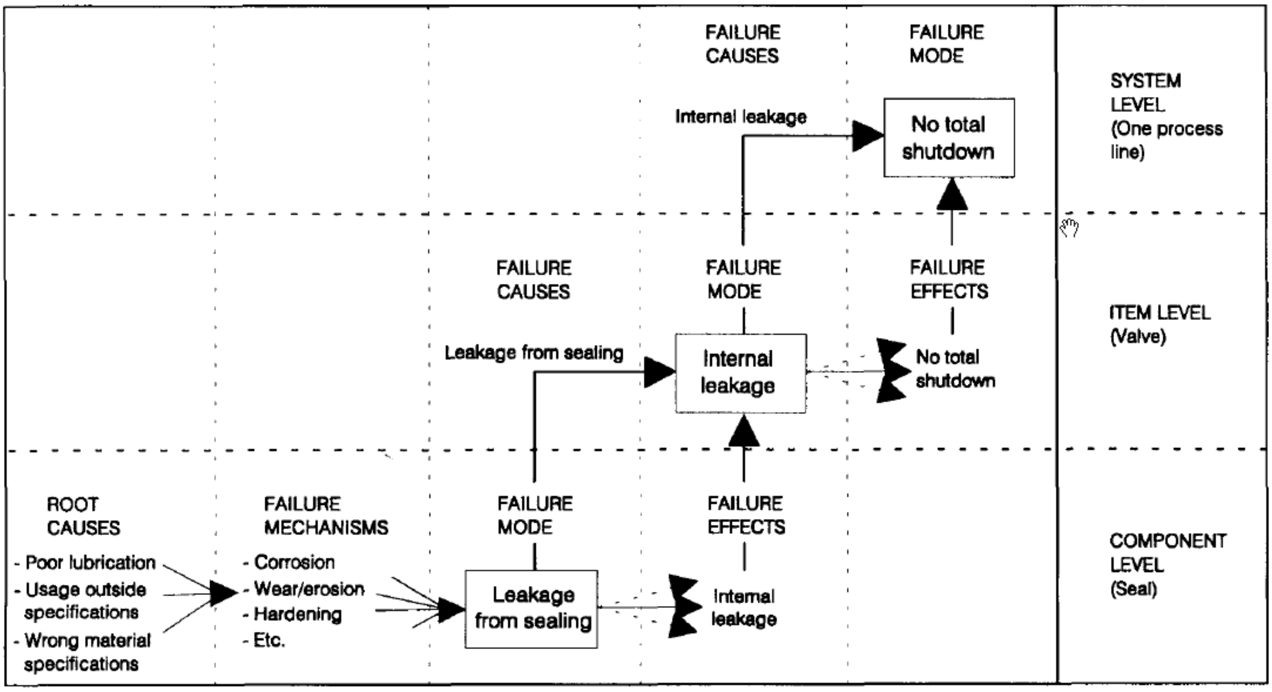

Figure 36: Relationship between failure cause, failure mechanism, failure mode and failure effect, [72]

B.5.2: Risk factors

In [23] Risk factors are defined as conditions or circumstances that can promote or accelerate degradation, or a lack of control, but are not necessarily sufficient for ageing to occur. They can be specific scenarios, occurrences or events that can predict or suggest that deterioration could occur in the future.

The risk factors may increase the probability of failure, and thereby affect the risk. Risk factors for the plant/equipment can include past events that could affect ageing. Table 33 is based on [23].

Table 33: Risk factors for ageing [23]

Risk factor	Details
Equipment age	The symptoms of ageing normally become more apparent with time, and older equipment may be expected to have more damage and deterioration than new. Age is not necessarily a risk factor. Older equipment that contained large design margins or has simply been well maintained may be still in an early Stage of life compared with newer equipment that has not been as well managed.
Equipment designed and manufactured to ‘old’ codes	Equipment designed and manufactured to supersede standards and codes may be more susceptible to ageing than more modern equipment. Parent metal quality, welder and procedure approvals, requirements and dimensional tolerances may not have been as well controlled, or at least not to current standards.

Risk factor	Details
Lack of low temperature justification	Equipment operated at low temperatures (generally below 0^oC) needs to be assessed against risk of brittle fracture, e.g. by using materials with specified low temperature impact values. Lack of low temperature justification is a risk factor for such equipment.
Outdated materials	The changes in steelmaking in the 1970s have resulted in much cleaner steels since then. Older steels can contain residuals (S and P) of 0.05%, whereas levels of 0.01% can now be obtained. The carbon level has also dropped over time as a result of modern microalloyed steels. This means that older steels have a higher tendency for cracking as a result of welding – particularly a consideration for repair welding older material.
Welding quality, defects and repairs	Poor quality of welding and joint design, are key factors promoting the onset of ageing damage. Welding has improved markedly during the last 40 years with better design, improved process control and quality standards. Modern welding consumables can also reduce the possibility of hydrogen cracking of arc welds. More effective ultrasonic NDT methods have improved the ability to detect and size weld flaws.
Equipment without fatigue assessments	Fatigue analysis considerations were not a requirement for general pressure vessels designed to the early construction standards. Often a limit to the number of stress cycles was given, but no further assessment was possible. Experience has shown that equipment designed to early codes before 1996, can experience fatigue problems in service.
Design fatigue life/ corrosion allowance utilised	Once the design fatigue life or corrosion allowance is used up, a thorough inspection and fitness-for-service assessment is normally required to extend life.
Re-occurring service problems – unplanned shutdowns	Any problem, no matter how small and insignificant, that continues to reoccur during service is an indication that conditions in the equipment are not optimised and may make it prone to degradation. Good inventory control is important for detecting these small but recurring faults.
Corrosive environments	A corrosive environment has the possibility of causing corrosion to exposed surfaces if not properly protected. Attention should be paid to crevices and stagnant areas and to regions of composition differences, such as at welds. Additionally, some materials are susceptible to stress corrosion cracking in specific environments.
Predictable deterioration	It is important to monitor the extent of predictable deterioration (e.g. wall thinning) through review of inspection reports and service history to determine the rate of ageing of the equipment. Was the predictable deterioration accurately anticipated from design?
Change of service	If the operating conditions of equipment change then it can have an increased risk of ageing until service history or experience shows otherwise. Particularly for equipment purchased second-hand.
Failure of cathodic protection systems or lack of records	If a CP system has failed, or records not adequately maintained, there is an increased risk of corrosion occurring.
Externals hazards, mechanical, thermal or fire damage	Surface impacts due to collision from moving equipment can result in small defects, which can act as initiators for mechanisms such as fatigue or corrosion. Thermal and fire damage can alter the metallurgy of a material so that it can subsequently lose strength, toughness or corrosion resistance.
Repairs	If repairs have been needed during the life of the equipment, the integrity and necessity of the repair will indicate the possibility for further problems.
Experience of ageing of similar equipment	Unless active measures have been used to prevent ageing of similar equipment it will be likely that the same problems can occur again.

B.5.3: Operational conditions

Operational conditions can contribute to ageing, acting through chemical and physical processes that affect material properties or functional capabilities. These are, based on [25]:

- Load (stress/strain) – dynamic and constant
- Environment (e.g. radiation, humidity, salinity, electrolyte composition, presence of gases)
- Process condition (temperature, pressure, relative velocity)
- Maintenance (testing , inspection, repair)

These must be taken into account when predicting the life time of SSC. They are also important when evaluating their robustness.

The relation between operational conditions and ageing mechanisms are discussed e.g. by [25], see Table 34 and Table 35 below. Further, reference is given to Appendix B of [77].

Table 34: Operational conditions, ageing mechanisms and consequences [25]

Operational condition	Ageing mechanism	Consequence/failure
Radiation	Change of properties	- chemical decomposition - strength change - ductility change - swelling - resistivity change - burn-up
Temperature	Change of properties	- strength change - resistivity change - ductility change
Stress/pressure	Creep	- changes of geometry (e.g. break, collapse)
Cycling of temperature, flow and/or load Flow induced vibrations	Motion	- displacement - change of position or set point - loose connections
	Fatigue	- break, collapse - deformation
	Wear	- deterioration of surface - change of dimension
Flow	Erosion	- strength change
Fluids chemistry	Corrosion/ galvanic cells	- release of radioactive material - strength change - deposition of particles - short circuits - leakage conditions

Table 35: Environmental operational conditions and ageing mechanisms [25]

Environmental operational conditions	Ageing mechanism	Consequence/failure
Humidity, salinity	Corrosion/galvanic cells	- leakage - release of radioactive material - strength reduction - deposition of particles - short circuits
Chemical agents	Chemical reactions	- undesirable chemical products - deterioration of structures

Wind, dust, sand	Erosion and deposition	- strength change - deterioration of surface - malfunction of components

Reference [25] also mentions non-physical operational conditions. These are presented in Table 36.

Table 36: Non-physical operational conditions and ageing mechanisms [25]

Non-physical operational conditions	Ageing mechanism	Consequence/failure
Technology progress	Shortage of spare parts, disappearance of suppliers	- maintenance difficulties
Change of safety	Obsolescence of existing safety components and systems	- interference with operation - modification of safety related components and systems
Inadequate design	Various	- accelerated ageing - may cause or support other undesired events
Improper maintenance and periodic testing	Various	- deterioration of systems

Changes in operational conditions are important. At the time of manufacture, pressure equipment normally has a validated design for a prescribed set of defined operating conditions. On the other hand, non-pressure equipment, as used for the containment of chemicals (e.g. storage tanks, hold vessels, mixers etc.) may be in service with very limited documentation of design conditions or defined operating limits. Changes to the operating regimes of both these types of equipment, or to their physical structure, commonly occur over the many years that equipment is in service. Some examples of operational changes are (see [23]):

- Changes in temperature
- Changes in pressure
- Changes in flow rates
- Modifications of process chemistry/environment
- Modification to product density
- Changes to system loading (e.g. pipe re-routing/hangers etc.)

Any of these may result in conditions outside the original design envelope or the condition under which satisfactory operations have been demonstrated. For mechanical equipment (e.g. pumps, centrifuges etc.) there may be other factors, for example, the speed of operation or the load carried. In addition, changes to drives, coupling, available spares or lubricants may alter dynamic loads, and ultimately affect integrity.

Examples of *changes* in operation parameters are higher cyclic loads, thermal shock, different flow conditions, valve closure ties, depressurisation times (see [23]).

In many cases during fitness-for-service assessment where damage has been detected, it has become clear that changes in operation increased degradation rates or introduced mechanisms that were not considered at design. Small changes that may not have been significant, as individual steps (e.g. small temperature changes, modified flush systems) became important over extended operation. It is often difficult to predict the impact of process change over an extended period, and where there is doubt increased monitoring and/or inspection is appropriate [23].

B.5.4: Indicators

We may define an indicator of ageing as a sign or evidence that some damage has already or is about to occur, and can be thought of as symptoms of ageing damage. These can be based on monitoring, e.g.

- Corrosion monitoring
- Wall thickness monitoring
- Erosion/sand monitoring
- Vibration monitoring.

However, broader definitions can also be given, and various types of indicators have been suggested to monitor ageing and ageing related phenomena.

Symptoms of ageing related challenges are, [25]

- distortion of dimensions,
- status of surfaces or materials,
- leaks,
- cracks and
- discoloration.

The report [23] presents various suggestions for ageing indicators, ref. [77]. Here [23] defines an indicator of ageing as a sign or evidence that some damage has already or is about to occur, and can be thought of as symptoms of ageing damage.

Following [87] *integrity indicators* can be based on

- Design life
- Compliance with standards
- Inspection, monitoring, testing and data trend analysis.

The standard PrEN 15341 gives a list of Maintenance Key Performance Indicators (KPI). Typical examples are:

- Total maintenance costs
- Unavailability costs related to maintenance
- Personnel costs spent in maintenance
- Maintenance time
- Maintenance man-hours
- Unavailability due to maintenance (maintenance shutdown costs)
- Total operating time
- Number of failures
- Number of failures causing damage/injury.

[15] points at the following categories of indicators/measurements:

1. Monitoring of physical parameters related to ageing
    - Visual inspection (temperature, vibration, noise, smell, etc.)

- Parameter monitoring (temperature, vibration, noise, …)
- Degradation of oil by taking samples

2. Maintenance measures
   - Visual inspection. Remove covers, take to pieces etc.
   - Physical measuring. Measuring bearings, internal surfaces, …
   - Contamination of oil by taking samples

3. Statistical methods
   - Data collection of component failure and exchanges
   - Tools for trend-spotting and alarm

4. Failure analysis
   - Failing components or old components carefully examined in search for ageing phenomena.

Further, the need to use expert judgments in the evaluations is pointed out in this book.

B.6: Hazards and undesired events

Table 37 presents major hazards and their significance for ageing [87]. So these hazards should be investigated in the risk assessment applied in the LE process.

Table 38 presents undesired events that will stress ageing.

Table 37: Major hazards, their consequences, and significance for ageing [87]

Major hazard	Consequences	Examples of the significance for ageing of systems
HC leaks	Shut down, loss of production, fire and/or explosion, asphyxiation	Over 60% of leaks on **HC systems** are caused by ageing processes such as fatigue, corrosion, erosion, degradation (HSE statistics) **Safety critical systems:** **ESD and BD system valves and pipe work** may operate less efficiently due to wear, corrosion, fouling etc.
Fire and explosion (usually as a consequence of a HC leak)	Reduced safety of personnel, damage to equipment, loss of production, structural failure, collapse, escalation	**Safety critical systems:** o Reduced sensitivity of gas, smoke and fire **detectors** with age due to poisoning of sensor, mechanical damage, window deterioration (infra-red detectors) o Reduced pumping rates and leakage of active and passive **fire systems** o Degradation of **PFP coatings** reduces heat resistant properties and fixtures weakened due to corrosion o Reduced fixing and integrity of **blast walls** due to corrosion and damage
Dropped objects	Rupture of vessels and pipe work leading to HC leaks etc, endangering personnel. Damage to safety critical systems	Fatigue and other ageing of lifting equipment components (**cranes**), e.g. gears, bearings, brakes, shafts, cables, slings etc

Major hazard	**Consequences**	**Examples of the significance for ageing of systems**
Structural collapse of topsides or topside equipment	Damage to **safety critical systems**, **pipe rupture**, HC leaks, loss of escape and rescue capability and routes	Fatigue and corrosion of **structural steelwork** can reduce load carrying capacity

Table 38: Undesired events stressing ageing [25]

Anticipated/Undesired event	**Consequence of event stressing ageing**	**Ageing mechanisms/effect**
Power excursion	Thermal and mechanical damage	- deterioration of systems - accelerated ageing
Flooding	Deposition and chemical contamination	- corrosion
Fire	Heat, smoke, reactive gases	- reduction of strength - corrosion

APPENDIX C: Reviewed reports, documents, standards and guidelines

This chapter gives references to the most of the applied literature in the report. Some main results from this literature are referred regarding models of ageing, ageing management, preventive maintenance (testing, inspection, monitoring and preventive actions), factors affecting ageing (risk factors, operational conditions) and indicators.

It should be noted, that the terminology in the present chapter may vary and/or differ from the rest of the report, as this chapter refers to reviewed literature.

The main literature reviewed is listed below and are mainly documents recommended from PSA, and include articles, reports, standards, guidelines etc. split on offshore, nuclear industry and aviation; see Table 39 - Table 41. For each reference we list the relevant topics related to ageing and life extension for offshore facilities.

In addition, Table 42 gives a summary of which of the following generic topics are described/mentioned in the various documents:

- Ageing and degradation mechanisms and failure modes (i.e. ageing effects)
- Performance indicators
- Barriers
- Indicators and detection
- Ageing management
- Mitigation and protection
- Integrity
- LE assessment
- Decision making and acceptance criteria (AC)
- Maintenance and modifications

Finally, Table 43 gives an overview of standards, guidelines etc. relevant for ageing and LE.

Note that a more comprehensive review of this literature is given in the Memo [77].

The list of literature treating ageing and LE of *specific* offshore system is rather limited. However,

Table 42 also gives which of the following specific systems that are covered (to some extent) in the various reviewed documents:

a. Wells
b. Pipelines, risers and/or subsea systems
c. Topside process equipment
d. Safety systems
e. Structures
f. Cranes

Note that only “systems” a, b, c, and d and f are discussed in the present report.

Further, system relevant documents with respect to degradation mechanisms, failure modes, maintenacne and life extension assessments are listed in the corresponding chapters on wells, pipelines/riser/subsea, process, safety systems and other.

The main topics with respect to ageing and life extension addressed in the literature review of the prioritised systems are:

1. Identification of system specific degradation mechanisms and failure modes
2. Existing, or input to, system specific LE assessment
3. Integrity

Offshore
Table 39 provides an overview of documents received from PSA and from their websites for offshore applications. Additional relevant documents are presented in the green-shaded rows at the end of the table. (--- means that no relevant information was found in the document)

Table 39: Main topics addressed in ageing and LE documents for offshore applications

Author (yr)	Document	General	Specific systems
Aalborg 2006	Safety and Inspection Planning of Older Installations	- RBI (based on cracks) - Inspection planning - Measures and indicators - Probabilistic fatigue modelling (SN-curves)	- Structures
BAE Systems 2001	Beyond lifetime criteria for offshore cranes	---	- Cranes (incl. ageing and degradation, QRA in the life of an facility, testing and inspections, ageing and degradation)
COWI 2003	Ageing rigs – Review of major accidents. Causes and barriers	- Barriers sensitive to ageing	- Structures and marine systems - (Process)
DNV 2005	Joining methods – Technological summaries	- Welding effects and NDT	- Pipelines
DNV 2006	Material risk – Ageing Offshore facilities	- Degradation mechanisms - Effect of degradation on robustness of facility - Failure modes - Monitoring and inspection - Material limitations / uncertainty / challenges - Recertification of well control equipment	- Wells - Structures (incl. concrete and steel) - Mooring systems - Pipelines
DnV 2007	Aker Kværner Subsea AS – Marathon Alvheim Wellhead fatigue HAZOP for AKS	---	- Well (incl. main contributors to reduce a Wellhead system life wrt fatigue, barriers, threats)
Ersdal 2005	Thesis on extending the life of existing offshore structures	- LE risks and hazards - Barriers and indicators	- Structures
Ersdal et. al 2008a	Life extension of mobile offshore units: How old is too old? Collaboration between the British and Norwegian Authorities (article)	- Needs wrt deterioration - Aspects of ageing - LE process - Assessment of LE (brief)	- Drilling units
Ersdal et.al. 2008b	Assessment of offshore structures for life extension (article)	- Technical, human and organisational aspects of ageing that reduce safety - Maintenance (inspection) of ageing	- Structures

Author (yr)	Document	General	Specific systems
		facilities - Methods for identifying focus areas for LE assessment - Methods for decision making - LE assessment of an existing offshore facility	
Hörnlund et.al. 2008	Ageing of materials (article)	- Functional requirement and selection for robust materials in design, and how this influences LE - Risk from ageing materials - Degradation mechanisms and failure modes - Assessment of LE; Key elements	- Structures (incl. concrete and steel) - Pipelines - Topside (incl. safety critical systems) - Drilling and wells - Mooring systems (incl. summary of degradation mechanisms and failure modes)
HSE 2000a	Fatigue Reliability of Old Semi-Submersibles	---	- Structures
HSE 2000b	Fatigue Reliability of Old Semi-Submersibles	---	- Structures
HSE 2004a*	Report on structural integrity and LE 1	- Long time safety review (data collection, hazard identification, SCEs, assessment for deterioration mechanisms and maintenance planning)	---
HSE 2004b*	Report on structural integrity and LE 2	- Safety critical element - Hazards and ageing processes - Maintenance (inspection and repair) - Current practise and LE - Standards and literature on ageing facilities and LE	---
HSE 2006	Plant ageing. Management of equipment containing hazardous fluids or pressure	- Ageing equipment at risk - References and websites - Maintenance policy - Strategies for managing degradation mechanisms - Main types of material damage and their causes - Indicators/symptoms of ageing and risk factors - Stages of progressive ageing - Inspection strategy approaches - NDT techniques and inspection methods	- Process
HSE 2007	Key Programme 3, Asset Integrity Programme	- Maintenance management and its performance - Findings from industry performance - Testing - Inspection programme and methodology	- (Safety systems)

Author (yr)	Document	General	Specific systems
ISO 2008	Pipeline Life Extension. ISO Recommended Practice	---	- Pipelines (incl. critical elements, LE process, PIMS, corrosion protection systems and corrosion assessment, condition monitoring)
May et al 2008	Structural integrity monitoring – Review and appraisal of current technologies for offshore applications	- Structural monitoring techniques/ methods - Inspection methods - Relevant codes and standards	(- Structures)
NORSOK 2008	Assessment of structural integrity for existing offshore load-bearing structures *NORSOK Standard N-006 (draft)*	- Assessment process (alternative to N-001 for ageing structures) - Collection of data - Corrosion and wear effects and protection - Fatigue and crack growth: Assessment, analysis, maintenance - Inspection, RBI	- Structures
OLF 2008a	Recommended guidelines for the assessment and documentation of service life extension of facilities. Including example of a typical Application for Consent *OLF Guideline No. 117 (draft)*	- Definitions - HSE and technical integrity and conditions - Gap analysis against regulations - Contents of assessment of LE	---
OLF 2008b	Life Extension of Facilities. Drilling and Well systems – List of issues that may be addressed	- LE general considerations, requirements and recommendations	- Wells
OLF 2008c	Recommended guidelines for Well Integrity	---	- Wells (incl. Well integrity fundamentals training, Handover documentation containment)
Poseidon 2006	Recommendations for design life extension regulations	- Elements of ageing that affect the safety of facilities - Degradation mechanisms - Hazards and failure modes - FUI and AC	- Fixed structures - Risers (limited) - Topside (limited)
Poseidon 2007b	Revised Structural Integrity Management Capability Maturity Model incorporating	- SIM terminology - Description of seven core processes wrt the five maturity levels	---
Poseidon 2007a	Report on work on ageing structures	- What can be learnt from decommissioned components - Summary of relevant standards	---
PSA 2005*	Summary of workshop on ageing and LE	- Summary of relevant papers - Phases of ageing	---
PSA 2008a	Assessment process	- LE assessment process	---
PSA 2008b	*Presentations* held on a construction conference at PSA	- Ageing mechanisms - Operator expectations in LE - Degradation mechanisms - Inspection - When FUI>1	- Structures
SEAFLEX 2007	Flexible Pipes. Failure modes, inspection, testing and monitoring	- Degradation mechanisms and failure modes, flexible risers - Integrity management, flexible risers - Inspection, monitoring, testing and	- Flexible risers

Author (yr)	Document	General	Specific systems
		repair, flexible risers - Recommendations for life extension of flexible risers	
Sharp et al 2005a	Managing life extension in ageing offshore Installations (Article)	- Generic and system specific ageing issues - SIM	- Topside equipment - Structures - Pipelines
Sharp et al 2005b	Life extension of ageing offshore installations – Role of structural integrity monitoring (Article)	- SIM an assessment	- Structures
Sharp et al 2008a	Development of key performance indicators for offshore structural integrity	- Key performance indicators (KPIs): Development of KPIs based on Hazards for structural integrity (extreme weather, fatigue, corrosion, geological, accidental), Application - List of potential KPIs for the hazards	- Structures
SINTEF 2003*	Pre-project: Robust material selection in the offshore industry	- Review of historic focus areas on material selection - Fracture and fatigue - Need for technology development - Corrosion: Protection and testing - Material concerns	- Topside process - Pipelines, risers and subsea
SINTEF 2004a	Material selection in the offshore industry	- Interaction between degradation mechanisms, lifetime predictions and design - Knowledge gaps	- Flexible risers - Pipelines
SINTEF 2004b	Robust material selection in the offshore industry – flexible risers	- Failure modes - Wear - Fatigue, corrosion fatigue - Hydrogen induced cracking - Recommendations	- Flexible risers
SINTEF 2004c	Material selection of weldable super martensitic stainless steels for linepipe material	- How a line pipe material responds to operational conditions - Corrosion, fracture, cracking - Knowledge gaps - Robustness improvement, e.g. monitoring (design and management)	- Pipelines (historical failures, degradation mechanisms)
SINTEF 2006	State of the art – ikke metalliske materialer inkludert sammenføyning	- Long lasting properties of materials - Environment influence - NDT methods incl. experiences	- Pipelines and risers - Misc: Standards, failure modes, risk and robustness, fatigue, testing for misc. systems
SINTEF 2007	Ensuring well integrity in connection with CO_2 injection	- Current practice related to well integrity - Materials, and degradation processes due to CO_2 - Well monitoring	- Wells (CO_2 injection)
Stacey et al 2008a	Life extension issues for ageing offshore installations	- Ageing - Relevant codes, standards and guidance for different LE features - Definitions of design life, LE - SIM plan - Assessment of structural integrity for LE - IMR	- Structures
Stacey et al	Structural integrity management	- SIM	- Structures

Author (yr)	Document	General	Specific systems
2008b	framework for fixed jacket structures	- Structural integrity improvement findings - Implementation of integrity management framework - IMR - Inspection strategies and methods	- Subsea
Stacey et al 2008c	Initiatives on structural integrity management of ageing North Sea installations	- Structural integrity strategy - Categorising of structural integrity into topics - IMR - Structural integrity management inspection programme (SIMIP) - Findings form inspection information on maintenance	- Structures (- Topside) (- Subsea)
Statoil 2002	Ageing and operability project. Mobile Drilling Units.	---	- Drilling units - Structures and marine systems
TWI 2007	Requirements for Life Extension of Ageing Offshore Installations	- Hazards and significance of ageing (stages of ageing) - Age related threats and damage mechanisms and the influence on equipment degradation - Barriers and the effects of and influence from ageing - Active and passive components - Integrity indicators; Inspection, monitoring testing and data trend analysis - Risk (age accelerating) factors - Generic framework for LE	- Topside process - Transportation systems - Safety critical systems
UiS 2007	Materials Testing of Decommissioned Offshore Structures	- LE strategies - Degradation mechanisms - Materials testing	- Structures

* Confidential reports

Nuclear industry (+ petroleum industry applications)

Table 40 provides an overview of documents received from PSA and from their websites concerning nuclear industry, but petroleum industry applications can occur. Additional relevant documents are presented in the green-shaded rows at the end of the table.

Table 40: Main topics addressed in ageing and LE documents for nuclear applications

Author (yr)	Document	General	Specific systems
Chockie 2006a	Ageing Management and Life Extension in the US Nuclear Power Industry	- Maintenance (inspection) of SSC (active versus passive) - Failure modes - Requirements and regulations - Relationship of maintenance and license renewal rules - LE implementation at plant - Ageing effects and mechanisms	---
Chockie 2006b	Condition Monitoring of Passive Systems, Structures and Components	- Maintenance (inspection) - Condition monitoring - Acceptance of LE; License	- Concrete structures

Author (yr)	Document	General	Specific systems
		Renewal Process	
Chockie (2006c)	Performance Monitoring of Systems and Active Components	- Maintenance - Performance monitoring - Typical Passive and Active Component Categories	---
DOE & EPRI 1996	Aging Management Guideline for Commercial Nuclear Power Plants – Tanks and Pools	- Ageing mechanisms and their significance (for different materials and process fluids) - Determination of influencing parameters - AMG (can be used as basis for other systems) - Ageing effects and AM program evaluation	- Tanks
IAEA 1992	Methodology for the Management of Ageing of Nuclear Power Plant Components Important to Safety	- Selection of components/systems for ageing - Methodology for AM study (understanding – maintenance) - Examples of ageing related component degradation and failure - Ageing degradation mechanism and susceptible materials and components - Examples of condition indicator trending as a basis for mitigating component ageing	- Component level
IAEA 1995	Management of research reactor ageing	- Definition of ageing - Service conditions contributing to ageing: Conditions – Ageing mechanism – Consequence/failure - Physical and non-physical conditions/mechanisms and effects of ageing - Selection and categorisation process of equipment susceptible to ageing - Ageing surveillance (inspection, monitoring, testing etc.) - Types of mitigation of ageing effects (inc. maintenance) - Degradation of materials - AM - Detection, assessment, prevention and mitigation of ageing effects	---
IAEA 1997	Assessment and management of ageing of major nuclear power plant components important to safety: Steam generators	-	- Steam generator and tubing, nozzles and shell (incl. degradation mechanisms, I&M, AMP, maintenance (repair and replacement)
IAEA 1998	Assessment and management of ageing of major nuclear power plant components important to safety: Concrete	- Ageing management (inspection, monitoring, assessment, remedial measures) - Ageing mechanisms and effects	- Concrete structures - Materials (incl. concrete, steel) and coatings - Seals and gaskets

Author (yr)	Document	General	Specific systems
	containment buildings	- Age-related degradation - Detecting ageing - Condition assessment	
IAEA 1999a	Assessment and management of ageing of major nuclear power plant components important to safety: PWR pressure vessels	- Ageing mechanisms (embrittlement, thermal ageing, fatigue, corrosion, wear, handling) - Inspection and monitoring (e.g. NDT) - Ageing mitigation methods concerning embrittlement and corrosion	- Vessels (incl. ageing assessment methods for relevant ageing mechanisms)
IAEA 1999b	Assessment and management of ageing of major nuclear power plant components important to safety: PWR vessel internals	- Ageing mechanisms (embrittlement, fatigue, corrosion, creep, swelling, wear) - Inspection and monitoring - Maintenance concerning the significant ageing mechanisms	- Vessels
IAEA 2000a	Advances in safety related maintenance	- Maintenance in general; Defining – Executing – Improving, performance criteria, tools & methods - Condition based maintenance - Life management	---
IAEA 2000b	Assessment and management of ageing of major nuclear power plant components important to safety: In-containment instrumentation and control cables. Volume I	- Ageing mechanisms and ageing of polymers - Main ageing mechanisms: physical and chemical, tools for identification of ageing mechanisms - CM: CI and available CM methods	- Cables
IAEA 2000c	Assessment and management of ageing of major nuclear power plant components important to safety: In-containment instrumentation and control cables. Volume II	(Rather detailed)	- Cables
IAEA 2005a	Assessment and management of ageing of major nuclear power plant components important to safety: BWR pressure vessel internals	- Ageing mechanisms (embrittlement, fatigue, SCC, general corrosion, erosion/corrosion, mechanical wear) and their significance - Maintenance (inspection, monitoring and replacement) - AM for fatigue and stress corrosion cracking - Mitigation methods	- Vessels
IAEA 2005b	Assessment and management of ageing of major nuclear power plant components important to safety: BWR pressure vessels	- Ageing mechanisms and their significance - Degradation mechanisms - Maintenance (inspection and monitoring) - Assessment methods for significant ageing mechanisms - Mitigation technologies	- Vessels
IAEA 2005c	Safety Culture in the Maintenance of Nuclear	- Ageing of plant (brief) - Ageing management; examples	---

Author (yr)	Document	General	Specific systems
	Power Plants	(brief)	
IAEA 2006	Understanding and Managing Ageing of Material in Spent Fuel Storage Facilities	- Ageing terminologies - Ageing of materials (steel, concrete) - AM - Introduction: Ageing sequence - Terms for degradation, LC and AM	- Auxiliary systems (brief in appendix I) incl. Structure – Material – Environment – Ageing effect/mechanism - Materials
INEL 1994	Ageing Study of Boiling Water Reactor High Pressure Injection Systems	- Degradation mechanisms (- Maintenance methods) - Component –Influencing parameters – Degradation mechanisms – Failure modes – Detection methods	- Process components (incl. instrumentation, electrical, pump, turbine, piping, valves): Influencing parameters – Degradation mechanisms, Failure modes, Failure cause, Ageing mechanisms & detection methods,
NUREG 2005a	Generic Aging Lessons Learned (GALL) Report – Summary, NUREG-1801, Vol. 1	- Component – Ageing effect/mechanism – AMP Listing of plant systems evaluated in Vol. 2	- Component level
NUREG 2005b	Generic Aging Lessons Learned (GALL) Report – Tabulation of Results, NUREG-1801, Vol. 2	- Structure and/or component – Material – Environment – Ageing Effect/Mechanism – AMP	- Component level
ODE 1994	Aging Management Guideline for Commercial Nuclear Power Plants – Motor Control Centers	- Applicable influencing parameters and ageing mechanisms – Activities that mitigate effects of ageing mechanisms - Effective management of ageing mechanism and maintenance for MCC systems/components	- Electrical system comps.

Aviation

Table 41 provides an overview of documents received from PSA for aviation applications.

Table 41: Main topics addressed in ageing and LE documents for aviation applications

Author (yr)	Document	General	Special systems
ATSB (2005)	How Old is Too Old? The impact of ageing aircraft on aviation safety	- Definitions of ageing - General ageing remarks - Determine system reliability - Managing aircraft ageing	---
Bristow et. Al (2000)	The meaning of life	- Ageing - Fatigue and cracking - AM	---
Bristow (2001)	Ageing airframes – A regulatory view from Europe	- AM - Corrosion prevention - Structural inspection - Repair assessment - Widespread fatigue damage	---

Summary

Table 42 summarises which key elements in ageing and life extension (to the left) and which critical systems (to the right), are referred to in the reviewed documents, listed in Table 39, Table 40 and Table 41, respectively.

Table 42: Summary – document contents

	Ageing and LE element										Critical system					
Author	**Degradation mechanisms and failure modes (i.e. ageing effects)**	**Performance indicators**	**Barriers**	**Indicators and detection**	**Ageing management**	**Mitigation and protection**	**Integrity**	**LE assessment**	**Decision making and AC**	**Maintenance**	**Structures**	**Topside process equipment**	**Wells**	**Safety systems**	**Pipelines, risers and subsea systems**	**Cranes**
Offshore																
Aalborg 2006					x	x				x	x					
BAE Systems 2001	x									x						x
COWI 2003			x					x			x	(x)				
DnV 2005	x					x				x					x	
DnV 2006	x							x		x	x		x		x	
Ersdal 2005			x	x							x					
Ersdal et. al 2008a	x							x			x					
Ersdal et. Al 2008b						x		x	x	x	(x)					
Hörnlund et.al 2008	x		x									x	x		x	
HSE 2000a											x					
HSE 2000b											x					
HSE 2004a*	x						x		x	x						
HSE 2004b*	x							x								
HSE 2006	x			x		x				x		x				
HSE 2007										x				(x)		
ISO 2008								x		x					x	
May et al 2008					x		x			x	(x)					
NORSOK 2008	x				x	x				x	x					
OLF 2008a							x	x								
OLF 2008b							x						x			
OLF 2008c							x	x					x			
Poseidon 2006	x								x		x	x			x	
Poseidon 2007a	x															
Poseidon 2007b	x						x									
PSA 2005*	x															
PSA 2008a								x								
PSA 2008b	x								x	x	x					
SEAFLEX 2007	x					x	x	x		x					x	
Sharp et al 2005a	x						x				x	x			x	
Sharp et al 2005b							x				x					
Sharp et al 2008a	x	x		X							x					
SINTEF 2003	x					x						x			x	
SINTEF 2004a	x														x	

	Ageing and LE element										**Critical system**					
Author	**Degradation mechanisms and failure modes (i.e. ageing effects)**	**Performance indicators**	**Barriers**	**Indicators and detection**	**Ageing management**	**Mitigation and protection**	**Integrity**	**LE assessment**	**Decision making and AC**	**Maintenance**	**Structures**	**Topside process equipment**	**Wells**	**Safety systems**	**Pipelines, risers and subsea systems**	**Cranes**
SINTEF 2004b	x														x	
SINTEF 2004c	x				(x)	(x)				(x)					x	
SINTEF 2006	x									x					x	
Stacey et al 2008a	x				x		x	x		x	x					
Stacey et al 2008b					x		x			x	x				x	
Stacey et al 2008c					x		x			x	x	(x)			(x)	
Statoil 2002											x					
TWI 2007	x		x	x			x	x		x	(x)	x		x		
UiS 2007	x							x		x	x					
Nuclear industry																
Chockie 2006a	x							x		x						
Chockie 2006b								x		x	x					
Chockie 2006c										x						
DOE & EPRI 1996	x	x			x							(x)				
IAEA 1992	x				x	x						(x)				
IAEA 1995	x			x	x	x				x						
IAEA 1997												x				
IAEA 1998	x			x	x					x	x					
IAEA 1999a	x					x				x		(x)				
IAEA 1999b	x									x		(x)				
IAEA 2000a										x						
IAEA 2000b	x									x		(x)				
IAEA 2000c												(x)				
IAEA 2005a	x				x	x				x		(x)				
IAEA 2005b	x				x	x				x		(x)				
IAEA 2005c	(x)				(x)											
IAEA 2006	x				x											
INEL 1994	x									(x)		x				
NUREG 2005a	x															
NUREG 2005b	x															
ODE 1994	x	x			x	x				x		(x)				
Aviation																
Bristow et. al 2000	x				x											
Bristow 2001	x				x					x						
ATSB 2005					x											

Relevant documents can also be found for other industries, e.g. the Norwegian standard NS 3424 "Condition survey of construction works – contents and execution" contains relevant bearings for a life extension assessment.

Table 43 lists some relevant standards, regulations, requirements, guidelines, codes etc. for life extension. The grey-shaded rows, is document already presented in the previous tables.

Table 43: Standards, guidelines, requirements etc. for life extension

Ref.	Standards etc.	Limitations	Contents and LE relevance
API RP2A	Tubular Joint Strength Design Provisions (2007)	Structures (Tubular joints)	*Not reviewed or references reviews*
API RP 2A-LRFD	API RP 2A-LRFD Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms - Load and Resistance Factor Design-First Edition (1993)	Structures	*Not reviewed or references reviews*
API RP 579	API RP 579 Assessment of fitness-for-service (refinery equipment)	Structural and process equipment and welded components	- Fitness-for-service and remnant life assessment
API RP2A-WSD	API RP 2A-WSD Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms - Working Stress Design-Twenty-First Edition (2005)	Structures (Fixed jackets)	- Maintenance - Fatigue and material properties.
API RP2-SIM	API RP 2-SIM Recommended Practice for he Structural Integrity Management of Fixed Offshore Structures (under development)	Main focus on fixed steel, but covers all structural forms	- Inspection - SIM
BS 7980	BS 7910 Assessment of flaws in metallic structures	Structural and process equipment and welded components	- Fitness-for-service and remnant life assessment
DnV RP F101	DnV RP F101 Assessment of corroded pipelines	Structural and process equipment and welded components	- Fitness-for-service and remnant life assessment
DnV RPC203	DnV RPC203 Fatigue Strength Analysis of Offshore Steel Structures	Structures	- Fatigue assessment (incl. a section on Extended Fatigue life)
IM 71002	Inspection Manual 71002 Licence Renewal Inspections	Nuclear industry	- Licence renewal
ISO 13822	ISO 13822 Assessment of existing structures (2001)	All types of existing structures	- General framework for assessment (similar as in ISO 19902)
ISO 19900	ISO 19900 (series) Petroleum and Natural Gas Industries – General Requirements for Offshore Structures (2002)		- ISO 19900 lists exceedance of the original design life as an initiator for platform assessment, (Poseidon, 2006)
ISO 19902	ISO 19902 Petroleum and natural gas industries – Fixed Offshore Structures (2007)	Focuses on fixed steel structures	- Assessment for existing structures. - SIM incl. inspection - Follows ISO 19900 in the respect of listing exceedance of original design life as an initiator for platform assessment, (Poseidon, 2006).
ISO 19903	ISO 19903 Petroleum and natural gas industries – Fixed concrete offshore structures (2006)	Fixed offshore structures	- Requirements to inspection and condition monitoring (ch. 14)
ISO 2008	Pipeline Life Extension. ISO Recommended Practice (2008)	Pipelines	- Critical elements - LE process - PIMS - Corrosion protection systems and corrosion assessment

Ref.	Standards etc.	Limitations	Contents and LE relevance
			- Condition monitoring
MC-2516	MC-2516 Policy and Guidance for License Renewal Inspection Programs	Nuclear industry; inspection	- Licence renewal
NEI 95-10	NEI 95-10 (Nuclear Energy Institute) Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule	Nuclear industry	- Licence renewal
NORSOK N-006 (*or* NORSOK 2008)	Assessment of structural integrity for existing offshore load-bearing structures NORSOK Standard N-006 (draft, 2008)	Load-bearing structures	- Assessment process (alternative to N-001 for ageing structures) - Collection of data - Corrosion and wear effects and protection - Fatigue and crack growth: Assessment, analysis, mitigations - Inspection, RBI - Improvement methods
NORSOK N-004	NORSOK N-004 Design of steel structures (2004)	Structures	*Not reviewed or references reviews*
NORSOK N-005	NORSOK N-005 Condition monitoring of load bearing Structures (1997)	Addresses all types of structures (fixed, steel, concrete, floating) but with relatively little detail on each.	- Overall principles for CM to maintain structural integrity
NUREG 2005a	NUREG-1800 Standard Review Plan for Review of Licence Renewal Applications for NPP	Nuclear industry	- Scoping and screening methodology for identifying structures and components subject to ageing management review - Ageing management of misc. systems / equipment
NUREG 2005b	NUREG-1801 Generic Ageing Lessons Learned (GALL) Report (2005)	Nuclear industry	- Component – Ageing effect/mechanism – AMP - Structure and/or component – Material – Environment – Ageing Effect/Mechanism – AMP
OLF 2008a	Recommended guidelines for the assessment and documentation of service life extension of facilities. Including example of a typical Application for Consent OLF Guideline No. 117 (draft, 2008)		- Definitions - HSE and technical integrity and conditions - Gap analysis against regulations - Contents of assessment of LE
RG 1.188	Regulatory Guide 1.188 Standard Format and Content for Applications to Renew NPP Operating Licenses	Nuclear industry	- Licence renewal

Also note that the following NORSOK standards on specific equipment have been useful, e.g. for system break down:

- NORSOK C-001 Living quarters area
- NORSOK C-002 Architectural components and equipment
- NORSOK D-001 Drilling installations
- NORSOK D-010 Well integrity in drilling and well operations
- NORSOK H-001 HVAC

- NORSOK L-001 Piping and valves
- NORSOK L-002 Piping design, layout and stress analysis
- NORSOK M-001 Material Selection
- NORSOK M-501 Surface preparation and protective coating
- NORSOK N-001 Structural design
- NORSOK N-003 Actions and action effects
- NORSOK P-001 Process design
- NORSOK P-100 Process systems
- NORSOK R-001 Mechanical equipment
- NORSOK R-002 Lifting equipment
- NORSOK R-003 Safe use of lifting equipment
- NORSOK R-004 Piping and equipment insulation
- NORSOK S-001 Technical safety
- NORSOK Z-008 Risk based maintenance & consequence classification
- NORSOK Z-013 Risk and emergency preparedness analysis

APPENDIX D: Degradation mechanisms and failure modes for flexible risers

This Appendix is based on [76].

Fatigue

All the materials used in the flexible riser cross section may be subject to mechanical fatigue. Normally, this is in focus only for steel components, but when investigating progression of damages within the flexible pipe cross section one should have in mind the effect of temperature cycle induced fatigue in plasticised Poly Vinyl Di Fluoride (PVDF), plastic as pressure barrier material for high temperature service. Fatigue in polymers is normally not regarded as a fundamental failure mode for un-bonded flexible pipes.

The carcass is made by cold forming thin steel ribbons into an interlocked flexible structure. Normally this structure will only see limited stress cycles and be more exposed to erosion or corrosion in case of sand or undesired chemicals in the well stream. Carcass fatigue has been experienced due to inaccuracies in the fabrication or load conditions changing the carcass performance. Recent experiences indicate that the carcass may see significant stress levels when the flexible riser is interacting with arch structures. Normally a fatigue crack in the carcass should not lead to loss of integrity for the flexible pipe, but this has been experienced. A complex interaction with the other cross section layers is needed for the damage to progress into a pipe failure, but the experience so far is that a failed carcass over time may progress further into a pipe failure.

Fatigue in tensile and pressure armour has been experienced in accelerated prototype testing and is currently no significant contributor to pipe failures in operation. Based on analysis performed in the design, fatigue failures are unlikely as the oldest flexible risers in operation in Norwegian waters are just above 10 years.

However, as the design analysis of most risers installed have assumed dry annulus environment there may be some risers that will experience less fatigue life than previously expected. Experience shows that nearly all production risers will fill up the riser annulus with condensed water. Differences will be seen due to different pressure barrier materials, well fluid, temperature etc.

Corrosion

If the external sheath is damaged, the armour wires in the pipe will be exposed to seawater. The wires will corrode if not efficiently protected by anodes in the vicinity. For flexible pipes with damages in the external sheath, some O_2 corrosion is observed, even when the pipe ends are connected to anodes. This is believed to be related to a possible problem of protecting shielded steel a certain distance away from the damage where the steel is not directly exposed to seawater.

Technip have studied the effect of corrosion protection of shielded steel in a test. The test concludes that steel wires in the vicinity of a damage external sheet area should be sufficiently protected against O_2 corrosion. The partial pressure of O_2 seems to fall quicker than the potential from the CP system along the pipe annulus away from the damage area. However, based on observed corrosion on other flexible pipes, it is reason to believe that the good effect of CP system further along the annulus (away from the external sheath damage) is very dependant upon high CP potential.

For external sheath damages in the waterline area where the effect of anodes is limited, several examples on significant O_2 corrosion have been observed, some with dramatic pipe failures.

CO_2 will diffuse from the pipe bore to the annulus if bore content include CO_2. The partial pressure of CO_2 in the annulus will vary along the riser. (NORSOK M-506) presents methodology and a calculation sheet for CO_2 corrosion, but is limited to partial pressure of CO_2 above 0.1bar. The corrosion rate for CO_2 partial pressure above 0.1 is higher than 0.1mm/year for any temperature between 10 and 60ºC and pH between 3.5 and 6.5. This indicates that CO_2corrosion may be a problem for flexible pipes with water filled annulus, however experience from dissections of damaged flexible pipes has concluded with very limited CO_2 corrosion compared to estimates based on (NORSOK M-506) for the tension armours of flexible risers and flowlines. CO_2 corrosion may be a long term problem for dynamically exposed risers due to reduced fatigue capacity in annulus environments with moderate to high CO_2 partial pressure.

Collapse
There are two different collapse scenarios that have been experienced by flexible pipes, collapse of internal pressure liner in smooth bore pipes, and carcass and pressure liner collapse in rough bore pipes.

Pressure liner collapse in smooth bore pipes is often seen on water injection pipes when vacuum is reached in the bore due to dynamic flow effects during shut down. There may be several ways to prevent this, but these compensating measures will often lead to operational restrictions. Both adjusted valve closing sequences, vacuum breakers and vacuum in the flexible pipe annulus may be viable options. The pressure sheath will eventually crack after a number of repeated collapses.

Carcass collapse in flexible pipes with multi layer PVDF pressure sheath has been experienced several times. The collapse is caused by an external pressure exceeding the capacity of the carcass. If the carcass has an initial damage or ovalisation the collapse capacity may be dramatically reduced.

The actual collapse capacity will be influenced by several factors: Geometry at the damage area, differential pressure, and 3D stiffness / load effects caused by the vicinity of the end fitting or clamps.

Preventive measures may be operational limits, restrictions in pressure relief gradients or design changes on the carcass.

Operation of a pipe with a fully or partially collapsed carcass may be possible for a short time, but movement of the pressure sheath will after some time lead to failure, if pressure or temperature is cycled. In addition, the lack of internal support may lead to failures in other layers; all dependants upon the cross section design.

Recent experiences have shown that carcass collapse due to pressure build up between pressure sheath layers may be more likely when the pipe is exposed to loads from interfacing structures that lead to initial ovalisation of the carcass. Such interfacing structures may be curved sections, bend stiffeners, clamps, guide tubes or arches.

Hydrogen embrittlement
Hydrogen embrittlement is known to cause failure of highly loaded high strength steel components protected by nearby anodes. Failures have been experienced in subsea equipment and ancillary equipment for flexible risers. No confirmed hydrogen embrittlement failures of flexible pipe armour wires are known, although some unexpected wire failures have been seen.

Hydrogen embrittlement of high strength armour wires could be disregarded as a primary failure mode, but connected to other initial failures, e.g. effects that give local stress concentration such failures may be seen.

Even if the material do not get brittle seawater, CP and high strength steel may give hydrogen production and a significantly reduced fatigue life, for dynamic applications.

Impacts
Local impacts from dropped objects, fishing equipment or equipment used during nearby marine operations may give a range of serious damages to the flexible pipe. Most commonly experienced failure mode from impacts is damages to the external sheath and subsequent local armour wire corrosion.

More severe impacts may lead to damages to tensile armour wires, unlocking of pressure armour layers or carcass ovalisation, potentially leading to a total pipe failure.

A general recommendation: If outer sheath damages expose the armour to seawater and CP, the exposure time should be limited.

Pigging
Smooth bore flexible pipes are often used in water injection systems. This design is significantly more sensitive to pigging damages. Pressure sheath damage due to pigging has occurred resulting in system shut down and riser replacement.

Carcass damages may result from pigging with erroneous pigs in flexible pipes. The carcass damage may develop into a carcass failure in dynamically loaded pipes.

Erosion
Sand in the production flow may lead to erosion of the carcass. Erosion is normally not a problem as long as operational limits to sand amount and flow velocities are adhered to.

Another related issue is internal pipe damages due to hydrates. Hydrates created in the flexible pipe or in interfacing pipes systems flowing into the flexible pipes may lead to severe damages to the carcass and subsequent pipe leak.

Buckling / over bending / wire disordering
Flexible pipes may buckle in case of compression loads over a certain limit. For static seabed lines protected by trenching and / or rock dumping special considerations must be made to avoid buckling. In the extreme event, buckling loads may lead to pipe over bending and wire disordering (bird caging). For static flowlines this failure mode has been experienced.

The different buckling modes seen in flexible pipes:

- *Lateral buckling due to over stress*: For a deep water pipe with an intact external sheath, the high frictional forces efficiently restrain the wires from moving until the critical curvature is reached. If exposed to axial compression combined with bending, the “locked or fixed” tensile armor wires could be exposed to compressive stresses above yield and hence fail by overstress.
- *Lateral buckling due to elastic instability*: For a pipe with damaged external sheath exposed to axial compression combined with bending, the radial movement will be

restrained by the high strength tapes, but lateral movement could occur with little resistance. Hence, in this case, lateral buckling due to elastic instability could occur. Excessive lateral wire movements could also lead to overstressing if reached before elastic instability occurs. New test methodology has been developed to test pipe designs and calibrate analytical tools for lateral buckling.

- *Radial buckling*: If the pipe is exposed to true wall compression, the helically laid tension armor wires will try to move in the radial direction possibly leading to wire buckling and significant disorganisation of the wires. This effect has also been known to happen during manufacturing. Radial buckling is often referred to as “bird caging”. However, for a pipe with intact external sheath, any radial movement of the wires will be efficiently restrained by the hydrostatic pressure acting on the external sheath. In case of a damaged external sheath, high strength tape layers applied outside the outer tensile armor layer will restrain the radial movement of the wires. Hence, for a properly designed flexible riser with or without intact external sheath, bird caging should not be an issue.

Wear
Flexible pipes in dynamic applications may be subject to wear between the steel armour layers. As these layers have been designed and tested to sustain normal wear loads, shortcomings in the design or changes in interface loads have to be present before wear develops into a failure.

Recent experiences with highly dynamic flexible risers installed in guide tubes, over subsea arches or through bending stiffeners have shown clear indications of excessive wear. Only on a few occasions have this wear lead to rapid degradation of pipe integrity. Geometry, surface roughness, and material selection seem to be important factors.

Vibration
High frequency vibrations have been observed in gas export and gas injection systems. The vibrations are believed to originate from the carcass where a vortex shedding process takes place as the gas flows over the carcass cavities. The phenomenon is currently not fully understood, however parameters including carcass geometry, gas velocity, gas pressure and gas composition affect the vortex shedding process and thereby the vibrations. The presence of acoustic amplifiers in the connecting steel piping is also believed to play an important role.

In one existing system, fatigue failure of topside piping has occurred and topside piping modifications were required in order to continue safe operation. In another system the subsea riser base was retrieved, modified and reinstalled due to components being identified as critical with regard to fatigue loading based on measured vibrations. Some systems experiencing vibrations continue to operate after stress checks by strain gauges have verified that the vibrations do not introduce unacceptable stress levels. It should also be noted that besides fatigue related problems, noise and increased flow resistance resulting from these vibrations have also been identified as a problem for some installations.

New projects planning gas export and/or injection through flexible risers address the potential vibration problem by implementing requirements on the flexible pipe and/or that interfacing piping systems shall not be fatigue sensitive with respect to potential vibrations. Acoustic dampeners or silencers are also being considered

APPENDIX E: Failure modes for safety systems (OREDA)

As pointed out the failure mode "Malfunction" (Section 3.1.2) must be specified further for the specific equipment types. Below we refer some failure modes from OREDA handbooks ([63], [64]) of various components in safety systems, (not complete).

Transmitters, (all types)

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Erratic output	Electrical failure - general	Continuous condition monitoring
		Faulty signal/indication/alarm	Production interference
	Fail to function on demand	Blockage/plugged	Continuous condition monitoring
		Electrical failure - general	Casual observation
		Faulty signal/indication/alarm	Continuous condition monitoring
		Instrument failure - general	Continuous condition monitoring
		Mechanical Failure - general	Functional testing
		No signal/indication/alarm	Functional testing
	Low output	Out of adjustment	Functional testing
	Spurious operation	Faulty signal/indication/alarm	On demand
		Instrument failure - general	Functional testing
		Mechanical Failure - general	Continuous condition monitoring
Degraded	Erratic output	Clearance/ alignment failure	Continuous condition monitoring
		Clearance/ alignment failure	Inspection
		Faulty signal/indication/alarm	Continuous condition monitoring
	High output	Faulty signal/indication/alarm	Casual observation
		Faulty signal/indication/alarm	Continuous condition monitoring
		Faulty signal/indication/alarm	Unknown
		Out of adjustment	Casual observation
	Low output	Clearance/ alignment failure	Continuous condition monitoring
		Faulty signal/indication/alarm	Continuous condition monitoring
		Vibration	Continuous condition monitoring
	Other	Corrosion	Casual observation
		Leakage	Casual observation
		Leakage	Continuous condition monitoring
		Misc. external influences	Continuous condition monitoring
Incipient	Erratic output	Clearance/ alignment failure	Continuous condition monitoring
		Faulty signal/indication/alarm	Continuous condition monitoring
		Faulty signal/indication/alarm	Inspection
		Faulty signal/indication/alarm	Periodic condition monitoring
	High output	Faulty signal/indication/alarm	Continuous condition monitoring
	Minor in-service problems	Clearance/ alignment failure	Casual observation
		Clearance/ alignment failure	Continuous condition monitoring
		Clearance/ alignment failure	Other method
		Leakage	Casual observation
		Leakage	Continuous condition monitoring
		Leakage	Corrective maintenance
		Wear	Casual observation

Process switch

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Erratic output	Faulty signal/indication/alarm	Production interference
		Out of adjustment	Production interference
Degraded	Erratic output	Faulty signal/indication/alarm	Production interference
	Other	Blockage/plugged	Continuous condition monitoring
Incipient	Minor in-service problems	Faulty signal/indication/alarm	Continuous condition monitoring

Detectors

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Fail to function on demand	Contamination	Casual observation
		External influence - general	Continuous condition monitoring
		Instrument failure - general	Casual observation
		Instrument failure - general	Continuous condition monitoring
		Instrument failure - general	On demand
		Out of adjustment	Functional testing
		Out of adjustment	Periodic preventive maintenance
		Short circuiting	Casual observation
		Vibration	Casual observation
	No output	Contamination	Continuous condition monitoring
		No signal/indication/alarm	Continuous condition monitoring
	Spurious high level alarm signal	Contamination	Casual observation
		Instrument failure - general	Casual observation
		Instrument failure - general	Continuous condition monitoring
		Out of adjustment	Casual observation
		Out of adjustment	Continuous condition monitoring
		Contamination	Casual observation
		Corrosion	Casual observation
		Instrument failure - general	Casual observation
		Out of adjustment	Casual observation
	Spurious operation	Contamination	Casual observation
		Contamination	Inspection
		Contamination	Periodic preventive maintenance
		External influence - general	Casual observation
		Faulty signal/indication/alarm	Continuous condition monitoring
		Instrument failure - general	Casual observation
		Looseness	Casual observation
		Misc. external influences	Casual observation
		Miscellaneous - general	Casual observation
		Out of adjustment	Casual observation
		Vibration	Casual observation
Degraded	Erratic output	Clearance/ alignment failure	Periodic preventive maintenance
		Contamination	Periodic preventive maintenance
		Faulty signal/indication/alarm	Periodic preventive maintenance
		Out of adjustment	Continuous condition monitoring
		Out of adjustment	Periodic condition monitoring
		Out of adjustment	Periodic preventive maintenance
		Vibration	Periodic preventive maintenance
	Fail to function on demand	External influence - general	Periodic preventive maintenance
		Out of adjustment	Periodic preventive maintenance
	High output	Contamination	Continuous condition monitoring
		Instrument failure - general	Functional testing
		Out of adjustment	Continuous condition monitoring
	High output, unknown reading	Instrument failure - general	Periodic preventive maintenance
		Out of adjustment	Periodic preventive maintenance
	Low output	Contamination	Periodic preventive maintenance
		Instrument failure - general	Continuous condition monitoring
	Low output, unknown reading	Instrument failure - general	Unknown
	Minor in-service problems	Clearance/ alignment failure	Casual observation
		Clearance/ alignment failure	Functional testing
		Out of adjustment	Functional testing
	Other	External influence - general	Periodic preventive maintenance
		Out of adjustment	Periodic preventive maintenance
	Spurious low level alarm signal	Instrument failure - general	Continuous condition monitoring
	Very low output	Out of adjustment	Periodic preventive maintenance
Incipient		Contamination	Continuous condition monitoring
		Leakage	Periodic preventive maintenance
		Out of adjustment	Continuous condition monitoring

Logic

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Erratic output	Open circuit	Continuous condition monitoring
		Unknown	Continuous condition monitoring
	Fail to function on demand	Common mode failure	Continuous condition monitoring
		Electrical failure - general	Casual observation
		Electrical failure - general	Continuous condition monitoring
		Electrical failure - general	Periodic preventive maintenance
		Other	Casual observation
		Other	Continuous condition monitoring
		Unknown	Casual observation
		Unknown	Continuous condition monitoring
		Unknown	Periodic preventive maintenance
	Spurious operation	Common mode failure	Continuous condition monitoring
		Electrical failure - general	Continuous condition monitoring
		Electrical failure - general	Functional testing
		Miscellaneous - general	Continuous condition monitoring
		No power/ voltage	Functional testing
		Other	Casual observation
		Other	Continuous condition monitoring
		Unknown	Continuous condition monitoring
Degraded	Erratic output	Other	Casual observation
		Other	Continuous condition monitoring
	Fail to function on demand	Common mode failure	Continuous condition monitoring
		Common mode failure	Periodic condition monitoring
		Common mode failure	Unknown
		Electrical failure - general	Casual observation
		Electrical failure - general	Continuous condition monitoring
		Electrical failure - general	Functional testing
		Electrical failure - general	Unknown
		Misc. external influences	Continuous condition monitoring
		Other	Casual observation
		Other	Continuous condition monitoring
		Unknown	Casual observation
		Unknown	Continuous condition monitoring
	Minor in-service problems	No power/ voltage	Continuous condition monitoring
	Other	Other	Continuous condition monitoring
	Spurious operation	Common mode failure	Continuous condition monitoring
		Earth/isolation fault	Production interference
		Electrical failure - general	Continuous condition monitoring
		Unknown	Continuous condition monitoring
Incipient	Erratic output	Common mode failure	Casual observation
		Electrical failure - general	Continuous condition monitoring
		Electrical failure - general	Functional testing
		Electrical failure - general	Production interference
		Electrical failure - general	Unknown
	Fail to function on demand	Common mode failure	Continuous condition monitoring
	Minor in-service problems	Common mode failure	Casual observation
		Common mode failure	Continuous condition monitoring
		Earth/isolation fault	Continuous condition monitoring
		Electrical failure - general	Casual observation
		Electrical failure - general	Continuous condition monitoring
		Electrical failure - general	Functional testing
		Electrical failure - general	On demand
		Electrical failure - general	Unknown
		Mechanical Failure - general	Continuous condition monitoring
		Mechanical Failure - general	Unknown
		Misc. external influences	Continuous condition monitoring
		Short circuiting	Functional testing
	Spurious operation	Electrical failure - general	Continuous condition monitoring

Pilot/solenoid

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Fail to close on demand	Blockage/plugged	Continuous condition monitoring
		Control failure	Functional testing
		Instrument failure - general	Casual observation
		Instrument failure - general	Periodic preventive maintenance
		Looseness	Continuous condition monitoring
		Mechanical Failure - general	Production interference
		Out of adjustment	Continuous condition monitoring
		Short circuiting	On demand
		Instrument failure - general	Casual observation
		Instrument failure - general	Continuous condition monitoring
		Instrument failure - general	Periodic preventive maintenance
		Mechanical Failure - general	Functional testing
		Mechanical Failure - general	Other method
	Other	Faulty signal/indication/alarm	Continuous condition monitoring
		Misc. external influences	Periodic preventive maintenance
		No cause found	Continuous condition monitoring
	Spurious operation	Breakage	Casual observation
		Corrosion	Continuous condition monitoring
		Faulty signal/indication/alarm	Continuous condition monitoring
		Faulty signal/indication/alarm	Production interference
		Instrument failure - general	Casual observation
		Instrument failure - general	Continuous condition monitoring
		Instrument failure - general	Unknown
		Short circuiting	Continuous condition monitoring
	Structural deficiency	Material failure - general	Periodic preventive maintenance
Degraded	Abnormal instrument reading	Out of adjustment	On demand
	Delayed operation	Instrument failure - general	Continuous condition monitoring
		Instrument failure - general	Functional testing
		Mechanical Failure - general	Continuous condition monitoring
	External leakage - Utility medium	Instrument failure - general	Casual observation
		Leakage	Casual observation
	Internal leakage	Leakage	Casual observation
	Other	Cavitation	On demand
		Corrosion	Unknown
		Faulty signal/indication/alarm	Continuous condition monitoring
	Spurious operation	Instrument failure - general	Casual observation
Incipient	Abnormal instrument reading	Clearance/ alignment failure	Other method
		Faulty signal/indication/alarm	Continuous condition monitoring
		Instrument failure - general	Casual observation
		Instrument failure - general	Continuous condition monitoring
		Misc. external influences	Periodic preventive maintenance
		No signal/indication/alarm	Periodic preventive maintenance
		Open circuit	Continuous condition monitoring
		Out of adjustment	Continuous condition monitoring
		Out of adjustment	Functional testing
	External leakage - Utility medium	Leakage	Casual observation
		Material failure - general	Casual observation
		Material failure - general	Periodic preventive maintenance
	Low output	Faulty signal/indication/alarm	Continuous condition monitoring
	Minor in-service problems	Electrical failure - general	Periodic preventive maintenance
		Instrument failure - general	Unknown
		Mechanical Failure - general	Casual observation
		Mechanical Failure - general	Periodic preventive maintenance
		Misc. external influences	Other method
	Other	Faulty signal/indication/alarm	Periodic preventive maintenance
		Instrument failure - general	Continuous condition monitoring
		Out of adjustment	Periodic preventive maintenance
	Structural deficiency	Mechanical Failure - general	Casual observation

ESV

Severity	Failure mode	Failure mechanism	Detection (example)
Critical	Fail to close on demand	Earth/isolation fault	Other method
		Mechanical Failure - general	Casual observation
		Mechanical Failure - general	Other method
		Sticking	Production interference
		Unknown	Continuous condition monitoring
		Blockage/plugged	Other method
		Instrument failure - general	Other method
		Misc. external influences	Other method
	Spurious operation	Looseness	Production interference
	Structural deficiency	Wear	Production interference
Degraded	Abnormal instrument reading	Control failure	Continuous condition monitoring
	Delayed operation	Misc. external influences	Other method
		Sticking	Production interference
	External leakage - Process medium	Leakage	Casual observation
		Material failure - general	Casual observation
	External leakage - Utility medium	Leakage	Casual observation
		Looseness	Casual observation
	Internal leakage	Leakage	Casual observation
Incipient	Abnormal instrument reading	Instrument failure - general	Other method
		Instrument failure - general	Periodic preventive maintenance
		Material failure - general	Functional testing
		Mechanical Failure - general	Other method
	External leakage - Utility medium	Corrosion	Casual observation
		Leakage	Casual observation
		Leakage	Unknown
	Minor in-service problems	Looseness	Inspection
		Mechanical Failure - general	Unknown
	Other	Mechanical Failure - general	Casual observation

APPENDIX F: Life Extension Assessment for material degradation (example)

This appendix presents an example of how a detailed analysis with respect to material degradation can be structured and carried out; presenting the following steps:

Step 0: Screening
Step 1: Collect background information
Step 2: Assess today's status
Step 3: Risk assessment
Step 4: Mitigation
Step 5: Implementation.

So the steps 1-5 give a description of the working process for the LE assessment at a defined analysis level. These represent a possible detailing of the steps 4-5 for *material degradation* (A) given in the "Framework for the LE process", cf. Figure 3 of Chapter 2. Appendix G gives a few examples of how such an analysis can be summarised.

STEP 0 SCREENING

Screening can be used both on system level and on component level. The screening should be based on risk and "knowledge"/accessibility.

First, ask whether failure of the system (or component) will cause one of the following (major) hazards:

- Explosion
- Fire
- Structural collapse
- Falling object
- HC leak (environment)

If yes, these are strong candidates for detailed analysis. Further, knowledge/accessibility is important for the screening. If the system is not accessible for obtaining detailed knowledge on the state, detailed analysis should be carried out. (Specific rules to be given.)

If decided by company a special follow-up plan can be developed and implemented for systems not subject to detailed analysis. This plan will be a part of the overall Integrity Management (IM) plan

Table 44: Output of STEP 0: SSC chosen for further analysis

ANALYSIS LEVEL					
SYSTEM		**STRUCTURE**		**COMPONENT**	
Number	**Name**	**Number**	**Name**	**Number**	**Name**
Unique system number	*Actual name of system*	*Unique structure number*	*Actual name of structure*	*Unique component number*	*Actual name of component*

STEP 1 COLLECT BACKGROUND INFORMATION

Goal: Collection and systemisation of information from design and operation.
Through: Access to design and operation information from as-built to today.

The required information is indicated in Section.3.1.4. Table 45 lists the output of STEP 1.

Table 45: Output of STEP 1

STEP 1 - BACKGROUND INFORMATION				
DESIGN & INST. PHASE		OPERATION PHASE		QUALITY OF INFORMATION
AVAILABLE	MISSING	AVAILABLE	MISSING	
Which relevant[1] design information is available and missing?		*Which relevant[1] information from operation is available and missing?*		*What is the quality of the available information?*

[1] Only include information that is relevant for degradation of the actual unit

STEP 2 ASSESS TODAY'S STATUS

Goal: Assessment of *today's status* of system/structure/component based on information from design, installation and operation from start up and until today.
Through: Review and analysis of information collected in Step 1

Output of STEP 2 is given in Table 46. The various columns in the table are described below.

Table 46: Output of STEP 2

STEP 2 – TODAY DEGRADATION STATUS			
DEGRADATION MECHANISM(S)[1]	FAILURE MODE(S)[2]	TODAY DEGRA-DATION STATUS	COMMENTS TO THE TODAY'S STATUS ASSESSMENT
Actual degradation mechanism(s) to be listed – Attachment 3 to be used	*Corresponding failure mode(s) to be listed*	*Today status through the ranking system – 1 to 5 – to be defined*	*Any comments to the to-day status evaluation?*

[1] Use character in Section 3.1.1
[2] Use Section 3.1.2

DEGRADATION MECHANISM
A set of degradation mechanisms has been developed (ref. Section 3.1.1). For each component actual degradation mechanism(s) under the actual conditions process- and operation conditions shall be defined. *Only the above pre-defined degradation mechanisms shall be used.*

FAILURE MODES
Each of the degradation mechanism is linked to a failure mode (see Section 3.1.2). For each component the actual failure mode(s) shall be described. *Only pre-defined failure mode(s) corresponding to the described degradation mechanisms shall be used, according to Table 4.*

TODAY'S STATUS
Today system/structure/component status shall be defined based on a ranking system. Table 47 shows the system to be used. Corrosion allowance (CA) and fatigue life (FL) are two examples of evaluation criteria for specifying degradation status.

Table 47: Example of approach to define *today's status*

TODAY STATUS	DEGRADATION STATUS	DEGRADATION[1)]	EXAMPLE
1	No	0%	Degradation can be defined e.g. in terms of corrosion, fatigue, wear or ageing of polymer materials.
2	Minor	0-10%	
3	Some	10 – 40%	
4	Severe	40 – 80%	
5	Excessive	> 80%	

[1)] Of accepted degradation during the *original design life*

COMMENTS TO THE TODAY'S STATUS ASSESSMENT
The quality of the assessment of the *Today's Status* is heavily influenced by the availability and the reliability of the background information. *In addition the competence of the personnel involved in the analysis is also important to give the best result.*

All available information from Step 1 *Background Information* shall be used during this status assessment.

STEP 3 RISK ASSESSMENT

Goal: Establish a risk level at the end of the life extension period (from today)
Through: An assessment of future condition based on *today's status* (Step 2) and information about *future operation conditions* (Step 1).

INFORMATION ABOUT THE OPERATION PHASE
It is important to collect and systemise information about *operation conditions during the remaining lifetime* (from today and until end of life; i.e. corresponds to life extension period). This includes:

1. Information about *planned* maintenance (repair) and modifications after Today status evaluation.
2. Process- and operation parameters (particularly changes from design condition). Reference is made to Section 3.1.3.
3. Changes in classification due to changing in operation parameters.
4. Length of the life extension period (number of years).

Output of STEP 3 is given in Table 48. The various columns in the table are described below.

Table 48: Output of STEP 3

STEP 3 – RISK ASSESSMENT						
PoF	**CoF 1)**				**RISK**	**COMMENTS TO THE RISK ASSESSMENT**
	A	**B**	**C**	**D**		
PoF value from the developed PoF scheme	*CoF value from the developed CoF scheme*				*RISK directly from the RISK matrix*	*Any comments to the Risk assessment?*

1) To define CoF for the four areas in the matrix

PROBABILITY OF FAILURE (PoF)
Based on today's status and information about the remaining operation phase (i.e. LE period), Probability of Failure (PoF) shall be defined. The following are valid for the PoF evaluation:

- The start condition is the actual today status (as defined in Step 2) if no repair or upgrade has been performed

The evaluation shall be valid for the end of the LE period. Table 49 shows a system to be used.

Table 49: System to be used to define the PoF values

PoF-category	DEGRADATION STATUS	DEGRADATION 1)
1	No	0%
2	Minor	0-10%
3	Some	10 – 40%
4	Severe	40 – 80%
5	Excessive	> 80%

1) Of accepted degradation at the end of the Life Extension period.

CONSEQUENCE OF FAILURE (CoF)
A system for defining consequence of a failure shall be developed. Normally CoF is based on the following areas ("dimensions"):

A. Personnel
B. Environment
C. Economy
D. Reputation

A categorisation of CoF with respect to these dimensions is indicated in Table 50; also see the consequence classification given in NORSOK Z-008.

Table 50: System to define the CoF values (example)

CoF - category	DESCRIPTION OF CONSEQUENCES			
	A.PERSONNEL	**B. POLLUTION**	**C. ECONOMY**	**D. REPUTATION**
1	Classification according to no. of injuries and fatalities	Classification according to e.g. tons of spill to sea (of various types)	Classification according to loss in million NOK, (e.g. due to repair and lost production)	Specific classification to be defined
2				
3				
4				
5				

The most critical value (highest value) from the CoF evaluation should be used in the Risk matrix (below) to define the Risk level at the end of the LE period.

RISK (R)
Risk is found as combination of PoF and CoF and is normally defined in a matrix shown in Table 51 below. The CoF values for the four areas shall be included. The highest CoF value can be used and combined with the PoF value to find the overall Risk level, to be inserted in the risk matrix (to the right). Here four values of risk are defined (L, M, H, VH). Suggested risk acceptance limits are also suggested by using colours green, yellow and red, so that both H and VH are defined as unacceptable.

Table 51: System to define the Risk level; example

CONSEQUENCEQUENCE OF FAILURE (CoF)					PROBABILITY OF FAILURE (PoF)				
CoF	**A.Personnel**	**B.Environment**	**C.Economy**	**D.Reputation**	**1**	**2**	**3**	**4**	**5**
1					**L**	**L**	**L**	**L**	**M**
2					**L**	**L**	**L**	**M**	**M**
3	***Classification rules to be defined, cf.* Table 50**				**L**	**M**	**M**	**M**	**H**
4					**M**	**M**	**H**	**H**	**H**
5					**M**	**H**	**H**	**VH**	**VH**

COMMENTS TO THE RISK ASSESSMENT
The quality of the risk assessment defining the risk level at the end of the LE period is heavily influenced by the reliability of the information about future operational conditions. *In addition, the competence of personnel involved in the analysis is important to give a reliable result.*

The risk assessment should cover both risks to the local system and risks towards other parts of the facility.

STREP 4 MITIGATION

Goal: Establish a mitigation plan for the system/structure/component to secure an acceptable risk level throughout the planned period of LE.

Through: A plan covering the need for

- Upgraded (repair/replacement
    - Immediately or at certain interval(s)
- Condition monitoring
    - Monitoring of process parameters
    - Monitoring of degradation
    - Monitoring of loads
- Inspection
- Testing

Output of STEP 4 is given in Table 52.

Table 52: Output of STEP 4

STEP 4 - MITIGATION				
UPGRADE	**CM**	**INSPECTION**	**TESTING**	**SPECIAL REQUIREMENTS**
Type of upgrade and when	*What, where (and when) to monitor*	*What, where and when to inspect*	*What, how and when to test*	*Description of special mitigation actions*

The mitigation plan shall describe the complete plan for upgrade, CM, inspection and testing for the life extension period. Existing plan for the previous exposure period shall be reviewed and actual elements shall if necessary be included as part of the new mitigation plan.

A general guideline for actual mitigation actions for the four risk levels shall be developed. The following general rule shall also be followed: The higher risk level the more detailed CM and inspection plan to be implemented. Table 53 below shows an example. However, this table is only a guideline and special requirements can be set up.

Table 53: System for defining the mitigation plan to secure acceptable risk level during the life extension period; (example)

RISK LEVEL	RECOMMENDED MITIGATION ACTIONS				
	UPGRADE	CM	INSPECTION	TESTING	COMMENT
L		X	X		Most important process and degradation parameters to be measured and inspection.
M		X	X		Extended CM and inspection program.
H		X	X	X	The higher the PoF, the more extended program.
VH	X	X	X	X	Mitigation actions depend on “quality” of upgrade.

The main reason behind the mitigation plan is to run the system at an acceptable risk level. By having access to information from condition monitoring, inspection and testing, PoF and risk level can be evaluated at certain intervals. If PoF increase a revised mitigation plane shall be put in place.

Input from condition monitoring, inspection and testing shall also be used for process adjustment and optimisation (e.g. reduce production rate to reduce sand production).

STEP 5 IMPLEMENTATION

Goal: Implementation of the mitigation actions described in Step 4.

APPENDIX G: Table for Life Extension Assessment of material degradation- Examples

The suggested table used in the previous Appendix for LE assessment of physical degradation is given below.

STEP 0 - LEVEL OF THE ANALYSIS						STEP 1 - BACKGROUND INFORMATION					STEP 2 - TODAY STATUS			STEP 3 - RISK ASSESSMENT								STEP 4 - MITIGATION				
SYSTEM		STRUCTURE		COMPONENT		DESIGN & INSTAL.		OPERATION PHASE		QUALITY OF INFORMATION	DEGRADATION MECHANISM(S)	FAILURE MODE(S)	TODAY STATUS	INFO. ON LE PERIOD	PoF	CoF				RISK	COM-MENTS	UPGRADE	CM	INSPECTION	TESTING	SPECIAL REQ-UIREMENTS
No.	Name	No.	Name	No.	Name	Available	Missing	Available	Missing							A	B	C	D							

Below this table is split into two parts and is applied for a couple of examples.

Example 1: EVALUATION - WELL AND SUBSEA

LEVEL OF THE ANALYSIS						STEP 1 - BACKGROUND INFORMATION					STEP 2 - TODAY STATUS			
SYSTEM		STRUCTURE		COMPONENT		DESIGN & INSTAL.		OPERATION PHASE		QUALITY OF INFORMATION	DEGRADATION MECHANISM(S)	FAILURE MODE(S)	TODAY STATUS	COMMENTS TO THE ASSESSMENT
No.	Name	Number	Name	Number	Name	Available	Missing	Available	Missing					
Example - Components constitute well barrier # 1														
	Åsgård sub.	X1	Well	Y1	SCSSV	1, 2, 3, 4, 5, 8	6, 7	10, 11, 13	12, 14, 15, 16	Limited quality of process data.	A, D1, F3	1, 5, 8	3	Water, H_2S, sand
	Åsgård sub.	X2	Well	Y2	Prod packer	1, 2, 3, 4, 5, 8	6, 7	10, 11, 13	12, 14, 15, 16	Limited quality of process data.	B5, G	5	4	Water, H_2S, sand
	Åsgård sub.	X2	Well	Y3	Prod tubing	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12, 13	14, 15, 16	Limited quality of process data.	B5, B6, E1, F3, K	1, 4, 5, 6	3	Inspection data shows high CR
Example - Components constitute well barrier # 2														
	Åsgard sub.	X1	Well	1	Prod. Csg	1, 2, 3, 4, 5, 8	6, 7	10, 11, 13	12, 14, 15, 16	Limited quality of process data.	B5, B6, E1, K	1, 4, 5, 6	2	
	Åsgård sub.	X1	Well	2	Wellhead	1, 2, 3, 4, 5, 8	6, 7	10, 11, 13	12, 14, 15, 16	Limited quality of process data.	B5, B6, E2, K, L	1, 4, 5, 6	2	

STEP 3 - RISK ASSESSMENT								STEP 4 - MITIGATION				
INFO. LIFE EXTENSION PERIODE	PoF	CoF				RISK	COMMENTS TO THE RISK ASSESSMENT	UPGRADE	MONITORING	INSPECTION	TESTING	SPECIAL REQUIREMENTS
		A	B	C	D							
20 (no), 21 (sand, P, T), 23 (15y)	3	1	3	4	4	H	60% of DL used		X	X	X	Testing according to requirements
20 (replace), 21 (P, T), 23 (15y)	2	1	3	4	4	M	Packer replaced before LE		X		X	
20 (no), 21 (sand, P, T), 23 (15y)	3	1	3	4	4	H	50% of WT removed		X	X	X	Caliper every 5 years
20 (no), 21 (P, T), 23 (15y)	3	1	4	5	5	H	Wear is a possible challenge		X		X	Caliper when prod.tubing is retrieved
20 (no), 21 (P, T), 23 (15y)	2	1	4	5	5	M				X		

Example 1 (cont.)

LEVEL OF THE ANALYSIS						STEP 1 - BACKGROUND INFORMATION					STEP 2 - TODAY STATUS			
SYSTEM		STRUCTURE		COMPONENT		DESIGN & INSTAL.		OPERATION PHASE		QUALITY OF INFORMATION	DEGRADATION MECHANISM(S)	FAILURE MODE(S)	TODAY STATUS	COMMENTS TO THE ASSESSMENT
No.	Name	Number	Name	Number	Name	Available	Missing	Available	Missing					
	Åsgård sub.	X1	Manifold	M1	Piping	1, 2, 3, 4, 5, 8	6, 7	10, 11	12, 13, 14, 15, 16		F2 (external)	1, 5	1	25% Cr SDSS - control stress/strain
	Åsgard sub.	X1	Manifold	M4	W inj. line	1, 2, 3, 4, 5, 8	6, 7	10, 11	12, 13, 14, 15, 16		B1, B6	5	1	CS - oxygen well under control
	Åsgard sub.	X1	Manifold	M5	Valves	1, 2, 3, 4, 5, 8	6, 7	10, 11	12, 13, 14, 15, 16		A, G, K	1, 4, 5, 6	2	25% Cr SDSS - polymer seals
	Åsgard sub.	X1	Manifold	M6	Prot. Struct.	1, 2, 3, 4, 5, 6, 7, 8		10, 13	11, 12, 14, 15, 16		B5	4, 5 (into legs)	1	CS, coating and CP

STEP 3 - RISK ASSESSMENT								STEP 4 - MITIGATION				
INFO. LIFE EXTENSION PERIODE	PoF	CoF				RISK	COMMENTS TO THE RISK ASSESSMENT	UPGRADE	MONITORING	INSPECTION	TESTING	SPECIAL REQUIREMENTS
		A	B	C	D							
20 (no), 21 (P, T, sand), 23 (15y)	1	1	4	5	5	M				X		Visual inspection with ROV
20 (no), 21 (oxygen), 23 (15y)	2	1	1	4	3	M			X			Monitor oxygen content
20 (no), 21 (P, T, sand), 23 (15y)	2	1	4	5	5	M	Wear can be a challenge during operation		X		X	
20 (no), 21 (CP level), 23 (15y)	2	1	1	1	1	L	PoF - anode consumtion			X		Visual inspection and CP survey

Example 2: EVALUATION - PROCESS SYSTEM

LEVEL OF THE ANALYSIS						STEP 1 - BACKGROUND INFORMATION					STEP 2 - TODAY STATUS			
SYSTEM		STRUCTURE		COMPONENT		DESIGN & INSTAL.		OPERATION PHASE		QUALITY OF INFORMATION	DEGRADATION MECHANISM(S)	FAILURE MODE(S)	TODAY STATUS	COMMENTS TO THE ASSESSMENT
No.	Name	Number	Name	Number	Name	Available	Missing	Available	Missing					
	Field A	16	Inlet system		***Complete***	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12	13, 14, 15, 16	Good - process	B1, B3, B6, D1, E2	1, 5, 6	2	Normal corrosion, low fatigue loads
	Field A	16	Inlet system		Manifold	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12, 13	14, 15, 16	Good - process & inspection	B1, B3, B6, E2	5, 6	3	Inspection data shows high CR
	Field A	16	Inlet system		Flowline A	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12, 13	14, 15, 16	Good - process & inspection	B1, B3, B6, D1, E2	5, 6	4	Inspection shows severe CUI
	Field A	20	1st St. Sep.		Separator	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12, 13, 14	15, 16	Poor inspection data	A, B1, B3, B5, D1, F1	1, 5, 6	3	Erosion in the bottom? External CUI?
	Field A	20	Line Sep 1-2		Line 1	1, 2, 3, 4, 5, 8	6, 7	10, 11, 12, 13	14, 15, 16	Good - process information	B6, E2	1, 5	1	Pipe made from 25% Cr SDSS- no insul.
	Field A	50	Seawater		Piping	1, 2, 3, 4, 5, 8	6, 7	11	10, 12, 13, 14, 15, 16	Good - T and res. chlorine	B2, B4, B6, D2, F2	1, 5	3	Based on CuNi 90/10 piping
	Field A	50	Seawater		Piping	1, 2, 3, 4, 5, 8	6, 7	11	10, 12, 13, 14, 15, 16	Good - T and res. chlorine	E2	1	1	Pipe made from Titanium Gr. 2

STEP 3 - RISK ASSESSMENT								STEP 4 - MITIGATION				
INFO. LIFE EXTENSION PERIODE	PoF	CoF				RISK	COMMENTS TO THE RISK ASSESSMENT	UPGRADE	MONITORING	INSPECTION	TESTING	SPECIAL REQUIREMENTS
		A	B	C	D							
20 (no mitigation), 21 (poor quality), 23 (15 years)	3	3	3	2	2	M	Uncertainty in process data		X	X		
20 (new inhibitor), 21 (poor quality), 23 (15 years)	3	3	3	2	2	M	Have to rely on new corrosion inhibitor (CI)		X	X	X	Control effect of CI
20 (repair CUI), 21 (poor quality), 23 (15 years)	2	3	3	2	2	M	Flowline replaced due to CUI incl. coating.	X	X	X		
20, 21 , 23 (15 years)	2	3	3	3	2	M	Detailed inspection after To-day status performed		X	X	X	Control effect of CI
21, 23 (15 years)	1	3	3	2	2	L				X		Visual inspection
20 (No planned), 21 (No) , 23 (15 years)	4	1	1	2	1	M	Due to local high velocities and coupling to Ti.		X	X		Control galvanic coupling and high vel.
20 (No planned), 21 (No) , 23 (15 years)	1	1	1	2	1	L	Assuming acceptable support.			X		Visual inspection

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