Guideline to Subsea Integrity Management - Wellhead to Topside ESDV

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Executive Summary

The study objective is to perform an overview of management and maintenance of subsea production systems and to provide integrity management guidance for all pressure containing components between the wellhead and the topside ESDV. The diverse subsea components (pipelines, risers, spools, valves) forming part of the hydrocarbon transport chain are designed according to various recognised standards, hence effective subsea integrity assurance is reliant upon a consistently applied risk management approach across a range of disciplines, systems and standards.

This report has been prepared in such a manner that it can be used as a guideline and reference text for operators and regulators of subsea production systems. It is not intended to present an overview or introduction to such systems.

Study scope and boundary including a subsea system overview schematic is presented in section 1.0, with subsea asset integrity grouping and technical interfaces further detailed in Table 4-2.

The focus of this guidance is on major accident hazard prevention. In practical terms, guidance is presented as a series of requirements and recommendations on a proposed series of key auditable elements as summarised in section 2.0.

An overview of good practice and guidance on subsea asset integrity management is provided in section 3.0, including a bow-tie representation showing the importance of technical, operational, organisational and human measures interacting to form part of preventive and reactive safety barriers given in Figure 3-1.

Life cycle integrity management guidance, and in particular the requirement to document and maintain focus on risk management / assessment throughout, is discussed in detail in section 4.0. The guidance is derived from lessons learned within the industry to date and includes specific considerations that may support the potential for asset lifetime extension.

Design standards for subsea components are summarised in section 5.0, including a discussion on how internal pressure definitions varies across design codes for different disciplines. Specific integrity threats and failure modes throughout the subsea system are discussed and presented in section 6.0 and Appendix A, including considerations related to general versus specific knowledge, detectability and observability of key known failure and degradation mechanisms. Currently available inspection and monitoring methods and integrity management measures are summarised in section 7.0.

A framework for development of an integrity management system is presented in section 8.0, including a process for program development, implementation and continuous improvement. Section 9.0 presents framework and method for lifetime extension studies and defines the importance of data availability and quality in this context.

Gaps and opportunities are identified in section 10.0. A particular challenge to effective IM implementation is a documented understanding of the pressure definitions and regime across the entire subsea production system (production, injection and control / chemical systems). This is a precursor to reliable risk assessment given the differing code requirements and physical characteristics of the various components. The pressure rating interface between primary pressure containment and control / relief systems must be well defined and demonstrated.

As subsea systems age, it is increasingly important that operational data is recorded and logged (including valve movements, periods of non-operation or abnormal conditions) such that operational trends may be established. Transfer of ownership or modifications to the subsea configuration over time represent a threat to data availability and quality in this regard.

The findings, conclusions and recommendations provided herein are based on work performed by the Wood study team and do not necessarily reflect the view of the Norwegian Petroleum Safety Authority (PSA).

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A	12 October 2020	Draft issue for review
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02	Prepared	Thomas Garten
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Table of Contents

List of Figures

List of Tables

1.0 Introduction and Scope

1.1 Objective, Scope and Study Boundaries

This guideline for integrity management between wellhead and riser topside ESDV has been developed by Wood on assignment from the Norwegian Petroleum Safety Authority (PSA). It covers subsea hydrocarbon containment barrier integrity management, with a focus on primary barrier and prevention of hydrocarbon loss of containment.

The study objective is to provide an overview of management and maintenance of integrity between Wellhead and Riser Topside ESDV, across disciplines, systems and standards.

Prevention of hydrocarbon leakage is often defined as a separate barrier (containment). The objective of this study project is to establish a comprehensive overview of how integrity is managed and maintained throughout the hydrocarbon transport chain between wellhead and riser topside ESDV, in order to prevent hydrocarbon leakage.

During the study work, emphasis has been placed on capturing system risks across interfaces between equipment and discipline interfaces and boundaries. Also, we have sought to highlight areas where gaps between common practice and state of the art methods and practice are identified. Similarly, there may be varying interpretations and implementations of standards and regulatory framework across different regions, operating companies and regulatory bodies which the study team has sought to include and discuss.

For systems review - wellhead, valves, rigid and flexible pipelines and risers are specifically covered with a focus on main equipment types and key risk areas. Study boundaries including interfaces to related equipment such as injection systems and safety critical control systems are further defined in the following sections, including an overview of equipment types included within this study.

This guideline is not intended to provide an overview or introduction to subsea systems, but rather assumes that individuals reading the report have a general knowledge of the design, manufacture and operational aspects of subsea systems, equipment types and components.

It has not been an ambition to provide an exhaustive overview of equipment types and associated risks, but this guideline should be read as an overview of key equipment and known risks. Reference has been made to main related standards for further details and this guideline does not replace any such governing standards. The findings, conclusions and recommendations provided herein are based on work performed by the Wood study team and does not necessarily reflect the view of the Norwegian Petroleum Safety Authority (PSA). Safety standards as per NORSOK S-001 and related standards are considered outside the scope of this guideline.

1.2 General

During the recent two decades, utilisation of subsea technologies has increased in development of offshore oil and gas fields. The increase is driven by subsea technology developments allowing for development of fields in deeper and more remote areas, maturing of technologies allowing for cost efficient implementation and advancement in the capabilities of subsea technologies including subsea processing and compression. Subsea pipeline systems in the North Sea dating back to the eighties are still in operation and many installations are operating beyond or approaching their original design life.

Different scenarios can lead to a requirement to extend subsea system life beyond the original design life, such as new technology increasing recoverable oil and gas reserves and drilling of new wells leading to subsea tie-backs into the existing infrastructure. If an Operator wishes to extend the life of an asset past its original design, a reevaluation of the design life is required. Operators should also consider risk exposure and how potential failures related to service time, such as corrosion and fatigue life are managed. The service life of a subsea system should be re-evaluated through a formal assessment to ensure safe and incident free operations. Lifetime extension methodology is further discussed in Section 9.0.

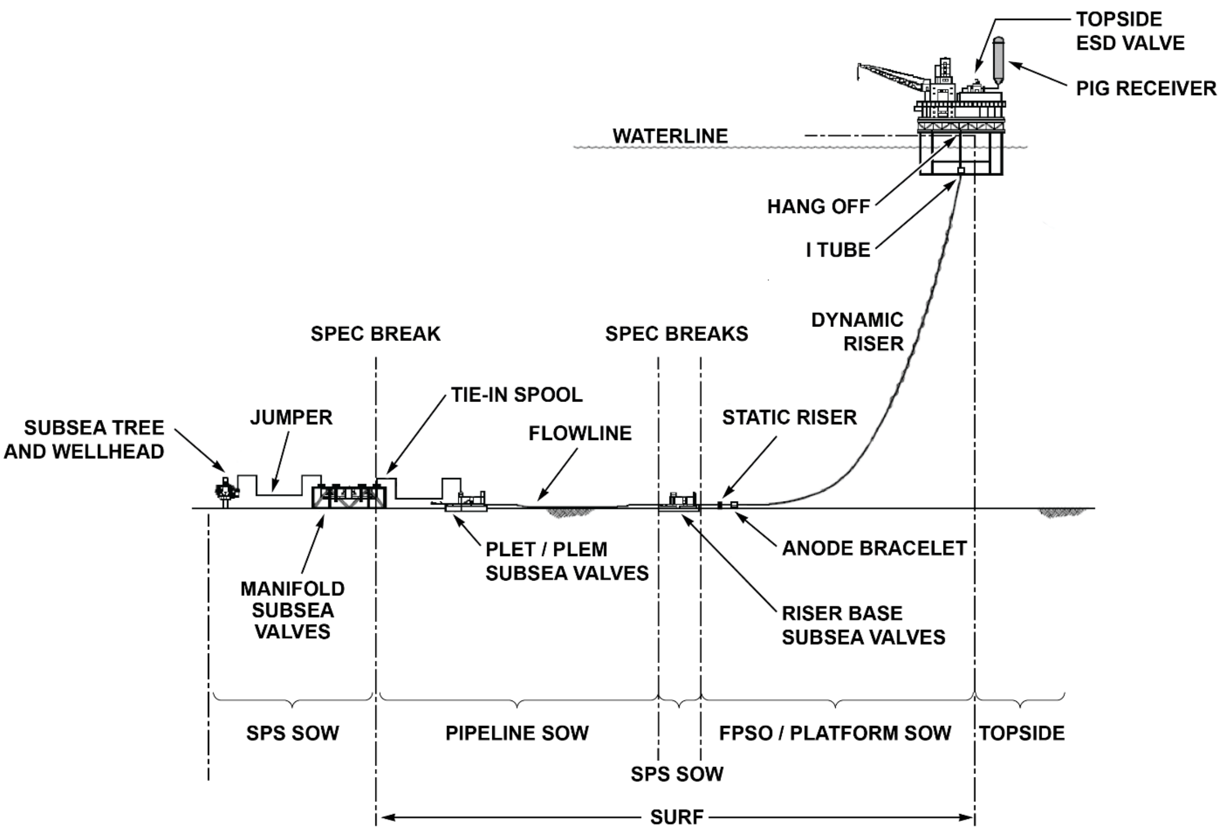

Figure 1-1 Subsea System Overview

Whilst the subsea system is often shown on a single "linear" path between the subsea wellhead and the topside ESDV as in Figure 1-1, the reality is rarely as simple. There are a number of interdependencies which must be managed within not only a single product stream being considered, but across other product systems, which makes most subsea systems complicated in their physical configuration and operational interdependencies. Further information relating to some of the challenges around these technical interfaces are detailed in section 4.16 of this report. A typical layout is illustrated in Figure 1-2.

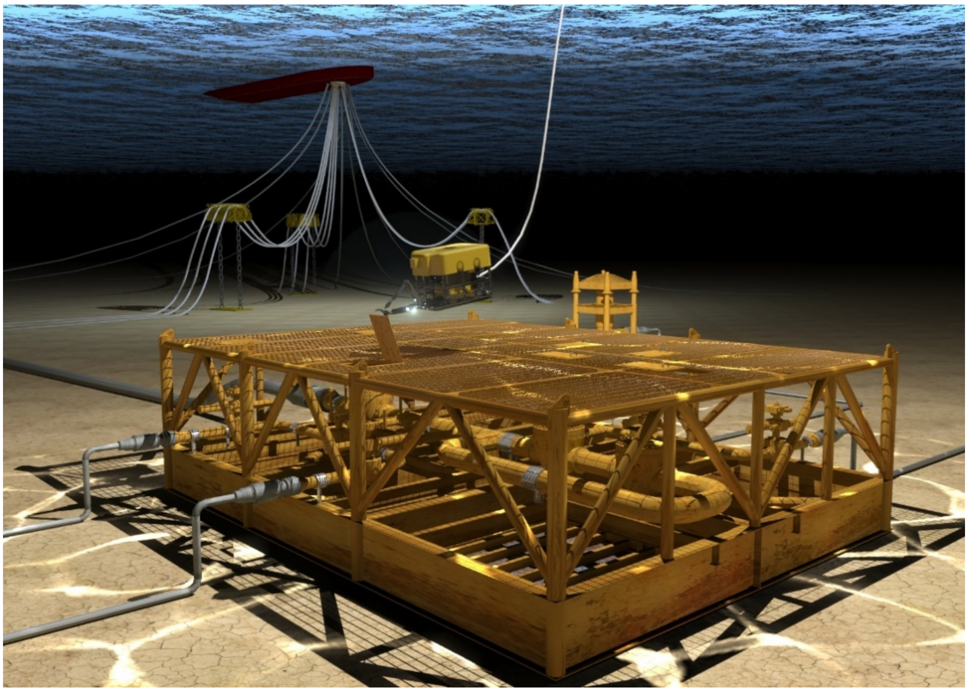

Figure 1-2 Subsea System Layout

Ageing of existing systems and increased complexity represented by new tie-backs to ageing pipeline systems, new technology developments such as subsea compression and processing combined with increasing demands for cost efficient operations impose a high requirement for targeted, field specific subsea integrity management (SIM) systems to be implemented.

1.3 Abbreviations

3D	Three Dimensions
ALARP	As low As Reasonably Practicable
ALE	Ageing and Life Extension
AM	Asset Management
API	American Petroleum Institute
API	Application Programming Interface
ASME	The American Society of Mechanical Engineers
BOD	Basis of Design
BSI	The British Standards Institute
BSSE	Bureau of Safety and Environmental Enforcement
BV	Barrier Valve
CAPEX	Capital Expenditure
CMMS	Computerized maintenance management system
CO_2	Carbon Dioxide
CoDam	Corrosion and Damage
CoF	Consequence of Failure
CP	Cathodic Protection
CSB	Chemical Safety Board
CVI	Close Visual Inspection
DFI	Design, Fabrication, Installlation
DSV	Diving Support Vessel
DFO	Documentation for Operation
DNVGL	Det Norske Veritas-Germanischer Lloyd
ECA	Engineering Critical Assessment
ESDV	Emergency Shutdown Valves
FAT/EFAT	Factory Acceptance Testing/Extended Factory Acceptance Testing
FEED	Front End Engineering Design
FFS	Fitness for Service
FLIP	Flow Induced Pulsation
FMEA / FMECA	Failure Mode, Effects, and Criticality Analysis
FPSO	Floating, Production, Storage, and Offloading

GIS	Geographic System Information
GoM	Gulf of Mexico
GVI	General Visual Inspection
H_2S	Hydrogen Sulfide
HAZID	Hazard Identification
HAZOP	Hazard and Operatibility Study
HCR	The Offshore Hydrocarbon Release
HMI	Human Machine Interface
HIPPS	High-Integrity Pressure Protection System
HIC/ SOHIC/ HISC	Hydrogen Induced Cracking/Stress Oriented Hydrogen Induced Cracking/Hydrogen Induced Stress Cracking
HSE	Health and Safety Executive (UK government agency)
HXT	Horizontal Christmas Tree
ILI	In-Line Inspection
IM	Integrity Management
IMR	Inspection Maintenance, and Repair
IOC	International Oil Company
IOGP	International Association of Oil & Gas Producers
ISO	International Organization for Standardization
ITM	Inspection Testing Maintenance
JIP	Joint Industry Project
JSA	Job Safety Analysis
KPI	Key Performance Indicator
LCI	Life Cycle Information
LoC	Loss of Containment
LP	Low Pressure
LTE	Lifetime Extension
MAH	Major Accident Hazard
MCS	Master Control Station
MoC	Management of Change
MPFM	Multi Phase Flow Meter
MWA	Mid Water Arch
NDE	Non-Destructive Examination

NCR	Non-Conformance Report
NCS	Norwegian Continental Shelf
NORSOK	Norsk Sokkels Konkurranseposisjon
NPD	Norwegian Petroleum Directorate
OD	Outer Diameter
OISDM	Offshore Infrastructure Survey Data Model
OPEX	Operational Expenditure
OREDA	Offshore and Onshore Reliability Data
PAP	Production Assurance Program
PARLOC	The Pipeline and Riser Loss of Containment
PDEF	Pipeline Data Exchange Format
PHD	Project Handover Document
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
PODS	Pipeline Open Data Standard
PoF	Probability of failure
PPS	Pipeline Protection System
PSR	Pipeline Safety Regulation
PT	Pressure Transmitter
PTIL / PSA	Petroleumstilsynet / Petroleum Safety Authority
QA/QC	Quality Assurance/Quality Control
RA	Risk Assessment
RACI	Responsible, Acccountable, Consulted, Informed
RAM	Reliability, Availability, and Maintainability
RBI	Risk Based Inspection
RBM	Risk Based Maintenance
RIAD	Reliability and Integrity Assurance Document
ROI	Return on Investment
ROV	Remotely Operated Vehicle
ROVSV	Remotely Operated Vehicle Support Vessel
RP	Recommended Practice
SCCB	Software Configuration Control Board

SCF	Stress Concentration Factor
SCM	Subsea Control Module
SCSSV	Surface Controlled Subsurface Safety Valve
SIF	Safety Instrumented Function
SIL	Safety Integrity Level
SIM	Subsea Integrity Management
SIS	Safety Instrumented System
SIT	System Integration Test
SME	Subject Matter Expert
SoW	Scope of Work
SSIV	Subsea Isolation Valve
SPS	Subsea Prodution System
SRB	Sulphate Reducing Bacteria
SSDM	Seabed Survey Data Model
SURF	Subsea Umbilicals, Risers, Flowlines
TRL	Technology Readiness Level
UHD	Ultra High Definition
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
UPDM	Utility and Pipeline Data Model
USV	Underwater Safety Valve
UT	Ultrasonic Testing
VIV	Vortex Induced Vibration
VXT	Vertical Christmas Tree
WHSIP	Well Head Shut-In Pressure
WOAD	Worldwide Offshore Accident Databank
XMT (VXT, HXT)	Christmas Tree (Vertical or Horizontal)

2.0 Overall Subsea System Assurance Recommendations

The development, implementation and maintenance of effective subsea integrity management (SIM) represents a challenging undertaking for operators of such systems. The challenge is primarily driven by the potential safety, environmental and commercial consequences of system failures in combination with equipment complexity, accessibility and inspectability. Industry legislation and regulations dictate that the operator is responsible for demonstrating that subsea production systems are operated in a safe and auditable manner.

While failure modes of individual subsea production equipment is relatively well understood by both manufacturers and operators alike, as existing subsea assets age or novel materials or equipment or design methodologies are deployed, there is an increasing requirement to consider the interdependencies and risks of the subsea system as a whole. This high-level requirement is termed overall subsea system assurance in this report.

The objective of this section is to summarise the key auditable elements of a subsea integrity management strategy, covering all sub-components and equipment between the wellhead and the topside ESDV. As such, this section and the accompanying Table 2-1 seeks to encapsulate the guidance presented within this report by:-

a) Identifying and listing the key auditable elements, namely:

    i. Subsea integrity management framework

    ii. System sub-division

    iii. Documentation management

    iv. Accessibility of historic / live operational data

    v. Threat assessment

    vi. Management of Change

    vii. In service integrity management

    viii. Lifetime extension

b) Providing cross references to specific guidance within sub-sections of this report,

c) Highlighting the key requirements for each element,

d) Providing recommendations on potential SIM gaps or pitfalls, based on industry experience.

It is not the intent of this guidance to identify a complete listing of auditable requirements, given the typical individuality of subsea production system design, layout and operational practice. Instead, the focus is to provide generic guidance to both operators and auditors on the system wide range of SIM elements that provide overall system assurance.

A total of 19 integrity assurance requirements and 18 individual recommendations are presented in Table 2-1. In addition, potential gaps and specific challenges to a SIM process are summarised in Table 10-1.

Auditable Element	Section Ref.	Key Requirements	Recommendations
i. Subsea integrity management framework	3.2, 3.3, 4.15, 8.0	1. Satisfy legislative and regulatory requirements with respect to major accident risk prevention 2. Define organisational responsibility and interfaces	1. Organisational responsibility chart specific to subsea integrity management should be maintained and actively implemented
ii. System sub-division	4.0, 4.16, Table 4-2, 5.0	3. To define technical interfaces at subsea system boundaries 4. For pressurised hydrocarbon retaining components, the governing design standards and associated operational pressure definitions / regimes should be understood and clearly communicated	2. Identification of all safety critical equipment, i.e. not solely pressure retaining components 3. Ensure that any opportunities for holistic production monitoring across interfaces are understood and actioned
iii. Documentation management	4.2, 4.4.6	5. Demonstrate that design phase documentation is traceable & complete 6. Demonstrate that SIM documentation is maintained	4. Provision and maintenance of a centralised document management system for subsea equipment through asset life
iv. Accessibility of historic / live operational data	4.1, 4.10, 4.11	7. Demonstration of operational data availability 8. Operator has established operational trends and is actively monitoring for operational changes 9. Logging of subsea valve movements and all abnormal / shutdown events	5. Graphical presentation of long-term operational parameters 6. Comparison of operational parameters (e.g. pressure, temperature, flowrate, fluid composition) with design intent 7. Awareness that degradation mechanism may be more onerous for equipment that is non-operational
v. Threat assessment	4.5, 4.8, 4.12, 4.14, 6.0	10. Equipment failure mode risk assessments completed and maintained (Appendix A presents a generic unmitigated threat assessment for typical subsea equipment) 11. Demonstrate an awareness of relative subsea component risk, e.g. operator understands relative utilisation levels across technical interfaces	8. Perform peer review of risk assessments 9. Cross discipline risk reviews 10. Appreciate the implications of emergent threats 11. Engage and collaborate with wider industry to share operational experience / learnings
vi. Management of Change	4.1, 4.6, 4.14, 4.16, 5.0	12. Demonstrate MoC process is in place and share relevant MoC examples 13. Implications of the change are assessed on overall system sub components 14. Demonstrate awareness and understanding of any changes or evolution in codes and standards	12. MoC process should describe communication channels, ensuring interdisciplinary expertise is captured 13. Carefully appraise whether replacement equipment should be treated as 'like-for-like' or 'new' 14. Highlight where operational changes impact safe operating limits
vii. In service integrity management	4.4.7, 4.5, 4.9, 4.10, 4.11, 7.0, 8.2.4	15. Actively maintained and documented SIM reports through life cycle 16. Presentation / demonstration of instrumented safety system controls and barriers 17. Anomaly tracking process	15. Understand extent and implications of any operational changes made to instrumented safety systems, e.g. disabled or inhibited alarms, bypassing of barriers or controls, LP trips etc 16. Regular system wide risk re-assessment and SIM updates
viii. Lifetime extension	9.0	18. Availability of through life SIM records and operational data history 19. Reassessment of threats	17. Corporate knowledge management & communications 18. Succession planning

Table 2-1 Auditable Elements of a Subsea Integrity Management Strategy

3.0 Overview of Good Practice and Guidance on Subsea Asset Integrity Management

3.1 History of Regulatory Framework

3.1.1 Precedent

At the time of writing, the industry was reflecting on the 40th anniversary of Alexander L Kielland, 32nd anniversary of the Piper Alpha disaster, and 10th anniversary of the Deepwater Horizon accidents. Learnings from these tragic major accidents have initiated much of the regulatory framework applied in the oil and gas industry today, to progress towards safety improvement by regulation, supervision, and clearly shared responsibilities. These accidents also serve as a reminder that knowledge and learning are dynamic processes and that stakeholders need to stay vigilant to apply historical learnings and experience to future challenges and technological developments.

While history has shown that all major catastrophic events in the oil & gas industry occurred due to combinations of multiple low-probability events and failures of numerous control barriers, it is important to look to these precedents as learning opportunities and a method for Integrity Management standards to lead the way instead of having industry responses post-events. Per the UK Parliament and National Commission on the BP Deepwater Horizon findings [1];

"*There is a sense that the industry seems to be responding to disasters after they have happened rather than anticipating and planning for high-consequence, low probability events*"

It would be advisable to note that although some incidents are caused by non-asset integrity failure, lessons learned and any changes to regulations will apply to operational assets and new equipment/systems being installed world-wide.

3.1.2 Historical Timeline

The table below captures a timeline of some major accident events and the subsequent actions by the regulators and stakeholders to address safety issues in the industry, with emphasis on integrity management. A summary of serious incidents where hydrocarbon containment was lost on the NCS or in the UK sector are also included, mainly based on incident databases.

Table 3-1 Offshore Oil & Gas Incidents and Integrity Timeline

Date	Incident / Integrity action
1980	Alexander L Kielland Accident
1981	The commission of inquiry into the Alexander L Kielland Accident report published
1985	Norway Petroleum Act
1988	Piper Alpha Accident
1990	Cullen Inquiry Report Published
1992	The UK Offshore Safety Act
1993	There was a leakage from a wellhead in the UK sector where approximately 13.5 m^3 of oil leaked out. The cause was mechanical failure during shut down of the well [2].
1996	A UK sector XMT was leaking and approximately 41.6 tonnes of gas leaked out. The operational causation in the HCR Database is "Dropped object".

Date	Incident / Integrity action
1996	A leak was discovered in the UK sector during final commissioning of a subsea manifold. The root cause was identified as hydrogen embrittlement (HISC).
1996	HSE Pipeline Safety Regulations launched
2000	HSE's KP1 (HCR Reduction) Inspection Programme Launch
2003	From July 2002 until January 2003 approximately 30 m^3 of oil was released due to wrong operation of a manifold valve on the NCS.
2003	Large uncontrolled oil spill from a NCS subsea installation when 500 – 800 m^3 of oil leaked out due to rupture in a connection between manifold and production line to platform.
2004	Well control incident on the NCS resulted in breach of well barriers and seabed gas breakthrough around platform.
2004	Norwegian Petroleum Directorate’s responsibility for safety was transferred to the newly established Petroleum Safety Authority Norway
2004	HSE's KP3 (Asset Integrity) Inspection Programme Launch
2006	HSE’s Asset Integrity Toolkit
2007	HSE's KP3-Asset Integrity Report launched
2009	HSE's Asset Integrity KPI Launch
2010	Deep Water Horizon Accident
2010	Well control incident on the NCS resulted in breach of well barriers and release of gas on the platform deck.
2010	HSE's KP4 (ageing & Life Extension) Inspection programme launched
2012	Oil & Gas UK Guidance on the management of ageing and life extensions for UKCS Oil and Gas installations
2012	Well control incident on the UK sector resulted in a gas leak lasting for 51 days before it could be stopped.
2013	An NCS bleed valve was set in the open position by a mistake, the estimated oil spill was 2.5 tonnes.
2014	Oil & Gas UK Guidelines on ageing and life extension (ALE)
2014	HSE Key Programme 4 (KP4) Ageing and Life extension programme
2016	Well barriers were breached during well workover operations on the NCS resulting in gas release through drill rig riser.
2016	Oil & Gas UK Guidelines on ageing and life extension of subsea pipelines and risers
2016	Oil & Gas Well Life Cycle Integrity Guidelines
2017	Oil & Gas UK Flexible pipe integrity management guidance and good practice

3.2 Safety Barriers

Section 4 of the Norwegian PSA Facilities Regulations [3] states major accident risk shall be the first consideration when choosing a development concept for offshore petroleum activities.

Sections 11 and 12 of Norwegian PSA Technical and Operational Regulations state requirements for risk reduction principles, organisation and competence targeted to reduce major accident risk, including reference to ISO 13623 and DNVGL-ST-F101 Appendix F which should be used with the following addition: "The pipeline system should be laid and designed such that the risk of fire, explosion and other unintended incidents is minimised, and such that the surroundings are affected as little as possible."

The integrity of subsea production systems is of significance to society and the environment. Several measures are necessary to maintain acceptable risk exposure:

- Preventive measures to reduce possibility of failure or accidents occurring
- Reactive measures which limit the consequential damage caused by such events occurring

The bow-tie diagram in Figure 3-1 below gives a possible way to illustrate how these barriers combine to mitigate the likelihood and consequence of such an event. In a wider perspective, these barriers embrace technical, human and organisational elements working together.

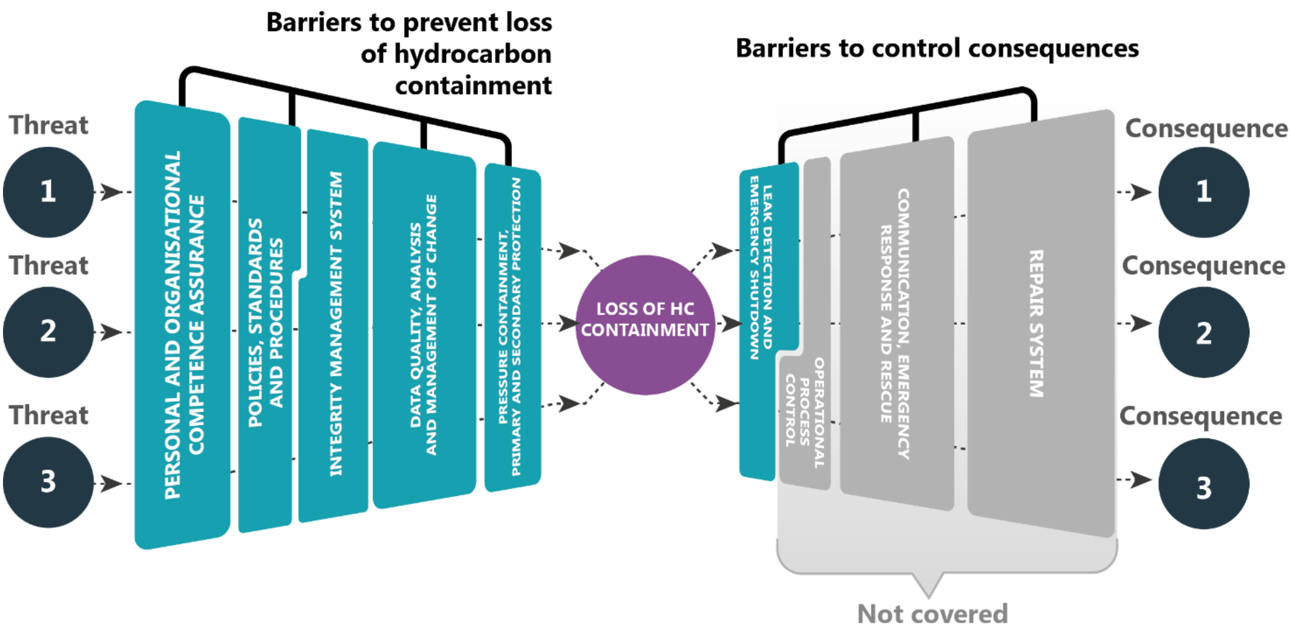

Figure 3-1 Barriers Bow-Tie

For the purpose of this guideline, barriers defined as any kind of measures put in place to prevent a hazardous event (preventive barriers) and any measure that breaks the chain of events to prevent or minimise consequences escalation should the hazardous event take place (reactive barriers). Such measures can be physical or non-physical (technical / human / operational / organisational).

Preventive barriers are illustrated on the left side of the bow-tie, whereas the reactive barriers are illustrated on the right side of the bow-tie. A top event can be the loss of containment or loss of operability due to for example loss of functionality of a valve. This guideline mainly considers as loss of hydrocarbon pressure containment as top event. Possible causes for a top event can be described by threats to the barriers and system.

This guideline is mainly focused on preventive barriers located on the left side of the bow-tie;

- "Personal and organisational competence assurance" should be a well-defined process in compliance with relevant international standards to ensure personnel with the correct competencies perform and check project and asset integrity management work, as further discussed in section 4.14.

- "Policies, Standards and Procedures" represent operational barriers, where key operational interfaces are discussed as part of project life cycle management in section 4.0, regulatory requirements and standards review summary is provided in section 5.0.
- A "Integrity Management System" framework is provided in section 8.0.
- "Data Quality, Analyses and Management of Change" is mainly covered as part of sections 4.0 and 9.0.
- "Pressure containment, primary and secondary protection" are technical barriers, where key interfaces are identified in section 4.16 and further discussed for main systems and disciplines in sections 6.3 through 6.6.
- "Leak detection and Emergency Shut Down" is introduced on a high level, mainly in sections 6.6.1 (valves types) and leak detection is identified as part of in service integrity management measures in Table 7-1.

It is noted that discussion of safety instrumented systems and their implementation according to related standards such as NORSOK S-001, ISO61508, ISO61511 and ISO/TR 12489 are considered outside the scope for this guideline. Bow-tie representation of safety instrumented system barriers may require a more stringent barrier definition than outlined above - where technical, organisational and operational elements may be defined as forming part of sub-functions to the main barrier function [4]. Safety valves are briefly introduced in section 6.6.1,but on a high level only.

3.2.1 Incident and Accident Databases

There are several incident, accident and failure data databases and reports available, including;

- IOGP – International Association of Oil & Gas Producers (www.iogp.org/bookstore/product/risk-assessment-data-directory-major-accidents/)
- WOAD – Worldwide Offshore Accident Databank
- PSA – Norwegian Petroleum Safety Authority Incident Database "Hendelsesdatabasen", CoDam database and Incident Summary Reports, [5, 6]
- HCR – The Hydrocarbon Releases Database System by Health and Safety Executive (HSE)
- CSB - Chemical Safety Board (www.csb.gov/investigations)
- BSSE – Bureau of Safety and Environmental Enforcement by US Department of the Interior (www.bsee.gov)
- PARLOC [7]
- OREDA [8]
- Sureflex JIP [9]
- Sintef – Ageing and life extension for offshore facilities in general and for specific systems [10]

3.3 Corporate Governance

Operators have the responsibility to ensure regulations are followed and are liable for any accidents or pollution. It is also best practice to refer to International standards where applicable in-order to conform to equipment and performance standards.

3.3.1 Regulatory Requirements and Standards

Whilst global operators all follow a similar approach with the key basic intent of managing the risks relating to failures of flexible pipes which could cause safety, environmental, financial, and reputational impacts, there are variations in the regulatory and legislative regimes which are in place in differing global regions.

Regulatory bodies in Norway and UK are introduced below.

3.3.2 Norway

The Petroleum Safety Authority (PSA) is an independent government regulatory body, with the responsibility for safety, emergency preparedness and the working environment in the Norwegian petroleum industry. The PSA regulates the health, safety and environmental (HSE) issues and concerns for all major accident hazard (MAH) pipelines systems within the Norwegian onshore and offshore petroleum industry.

The Norwegian Petroleum Directorate (NPD) is a governmental specialist directorate and administrative body, responsible for conducting metering audits and collating data from the oil and gas activities by means of judicious resource management based on safety, emergency preparedness and safeguarding of the external environment.

3.3.3 UK

The regulatory body for the UK is the Health & Safety Executive (HSE), with the main aim to secure the health, safety and welfare of people at work and protect others from risks to health and safety from work activity. The HSE regulate health, safety and integrity issues for major accident hazard (MAH) pipelines in the UK (onshore) and UKCS (offshore). Flexible pipelines and risers which fall into the MAH category are included within the "pipelines" definition.

The HSE approach to regulation is based on the (non-prescriptive) goal setting standards set out in the Offshore Installations (Safety Case) Regulations 2015, and the Pipelines Safety Regulations 1996 (PSR).

4.0 System Life Cycle Interfaces for Risk and Integrity Management

4.1 Project Life Cycle Management

Projects life cycle management is a core concept and tool to use in the development of any best practice guideline. Each phase of the project allows evaluation and assessment of the work performed, where risks and technical content is reviewed against the initial goals and requirements set out by the operator. Each project phase has its own set of "stage gates" or requirements before reaching completion. Integrity Management should be a key step in each phase and should be addressed as the project progresses.

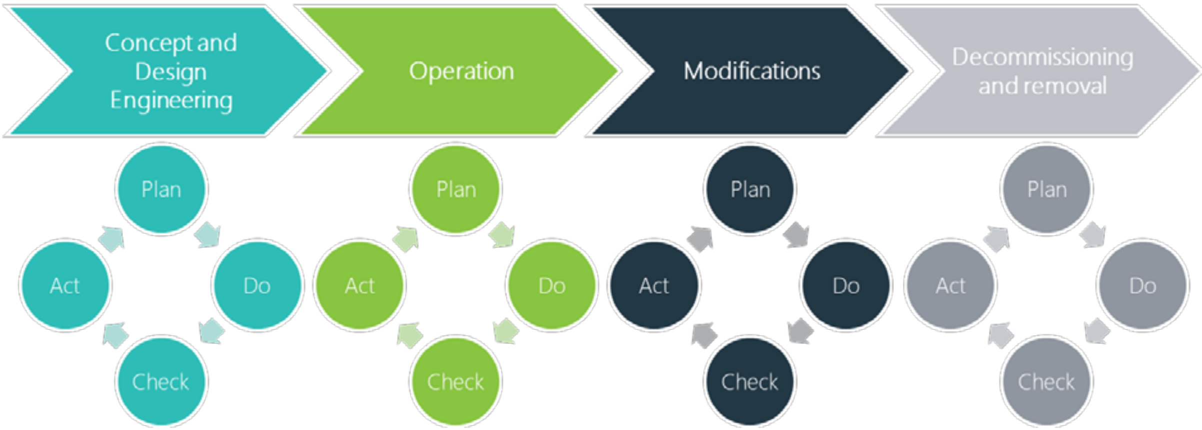

Figure 4-1 Barrier Integrity Management through System Life Cycle [11]

During the different design phases, the technical definition and specification of the system will be refined as the engineering assessments progress. This will in turn allow a better definition of the integrity risks associated to the system and necessary measures to manage these risks. At each stage of the development, these risks will be vetted against the work performed and checked to see if the project can move through the stage gate to the next phase of the project. A proper interface management between phases should be defined to assure that all identified integrity requirements are addressed and implemented during whole asset lifecycle.

The approach taken to both "routine" integrity management and life extension of subsea systems should be similar. Risk assessment and integrity management should be central to every stage through the life cycle, as illustrated in Figure 4-2. Issues relating to the "early life" stages of a pipe (e.g. manufacture, installation, commissioning and handovers) have the potential to impact operations into life extension. Data relating to operations and the management of change (e.g. change of use / application) through these operating phases is an essential requirement to support future life extension assessments. Further guidance on the life cycle integrity management stages shown in Figure 4-2 are presented in the following sections of this report.

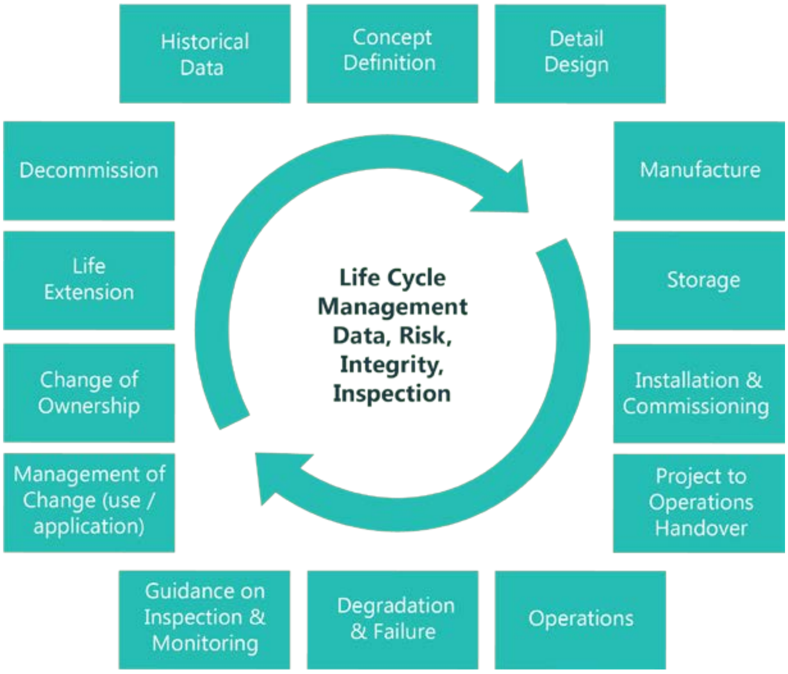

Figure 4-2 Life Cycle Integrity Management

The purpose of design and engineering is to prepare an asset for operations. A recommended best practice for data collection and documentation should include:

- Collect the data for operations from Day 1 of the project and maintain throughout the system life cycle
- Define and implement holistic and harmonized class library specifications (CMMS classes, engineering classes)
- Assure integrity between design and engineering tag databases
- Engineering tag database pre-populated with fields required for CMMS, Commissioning, Integrity, Ops attributes etc.
- Attributes populated by competent and qualified personnel who have a stake in the quality of the data for Operation Readiness Assurance activities
- Minimise number of databases and develop full integration where possible

4.2 Information Systems

The structure and relationship between tools and systems for data management through design, construction and into operations is illustrated in Figure 4-3. All subsea assets should have all project life-cycle documentation and data available and associated change recorded. This activity is often referred to as Life Cycle Information management systems (LCI). The documentation sets out the design criteria by which the asset meets safety, operational and other performance requirements.

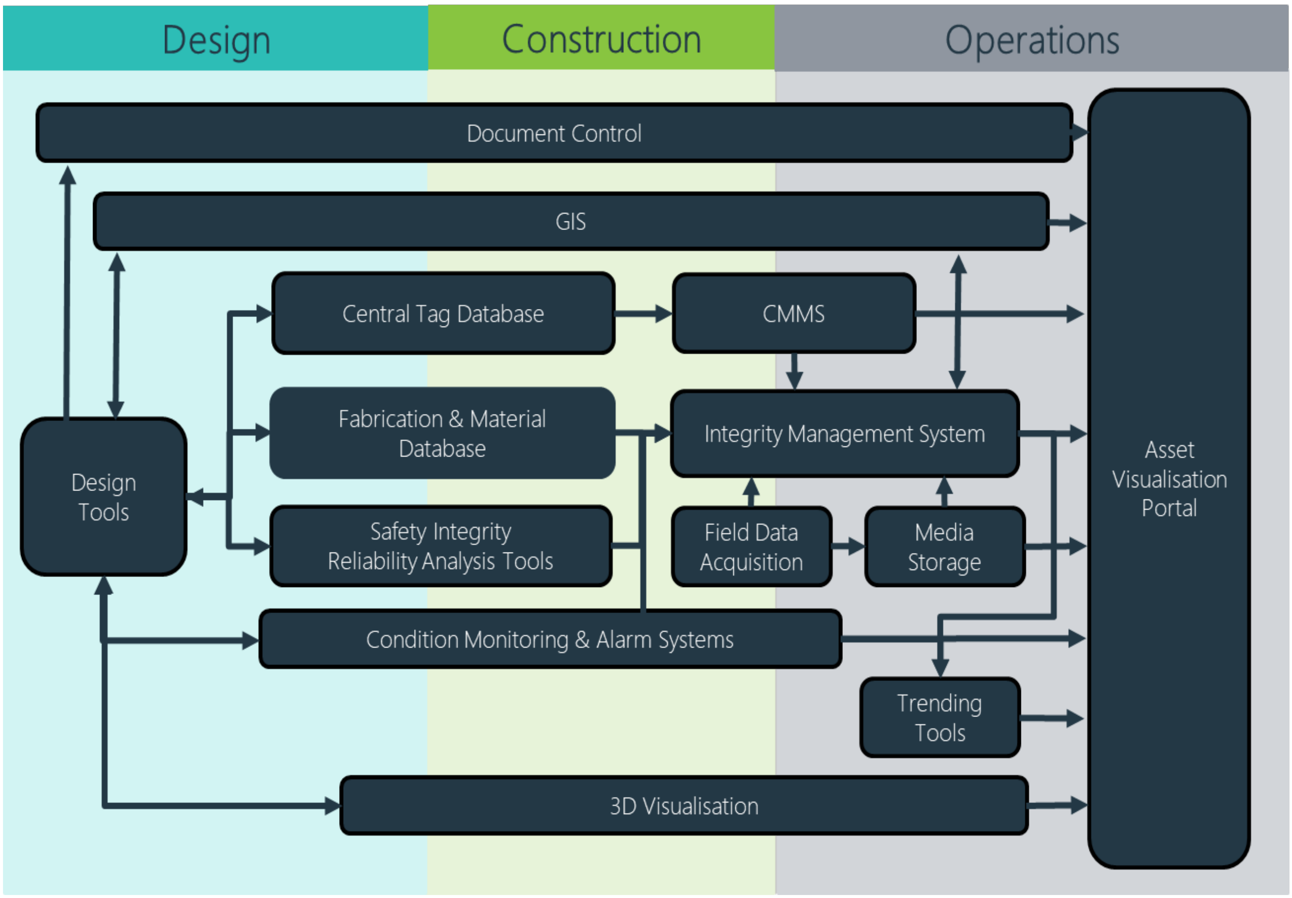

Figure 4-3 Data Management, Tools and System Overview

Information systems are a key part of the integrity management program, enabling the capture, storage, validation, query, analysis and reporting of key information across all phases of the asset lifecycle.

Geographic Information Systems (GIS) allow for information to be referenced to a specific location in the pipeline system. This enables disparate datasets to be overlaid, revealing trends, patterns and relationships in the information that are not otherwise visible. For example, locations of anomalies can be overlaid with materials, welding, coating and other similar information. Likewise, multiple historical inspection records can be overlaid to identify clusters of anomalies and changes over time.

Other media can also be referenced to specific geographic locations within the GIS, including documents, photos and video. This improves efficiency and reduces costs associated with locating information.

4.2.1 Information Systems Industry Standards

Several industry-standard GIS data models have been or are currently being developed. These enable sharing of best practice and simplify the exchange of information between operators, contractors and vendors. These standard models include:

- IOGP Seabed Survey Data Model (SSDM) – https://www.iogp.org/geomatics/
- IOGP Offshore Infrastructure Survey Data Model (OISDM) – currently in development
- Pipeline Open Data Standard (PODS) - https://www.pods.org/ (this is used both onshore and offshore)
- Utility and Pipeline Data Model (UPDM) - https://community.esri.com/docs/DOC-13587-updm-2019-edition
- Pipeline Data Exchange Format (PDEF) – currently in development (this is a data exchange format rather than a data model)

4.3 GIS Technology

GIS professionals use desktop GIS software to manage data, perform analysis and provide static outputs such as reports and charts. To make the GIS information accessible to a broader user base, web-based GIS applications are becoming more widely adopted.

An example web-based GIS portal as illustrated in Figure 4-4 which can include:

1. Seabed survey data including bathymetry, slope, geohazards and locations of other nearby infrastructure
2. Asset information including pipelines, subsea equipment, jumpers, controls, mooring lines and other subsea infrastructure
3. Pipeline features such as valves, anodes, buoyancy modules, strakes, crossings, spans and touchdown locations
4. Materials information such as manufacturer, dimensions, grade, specification and heat numbers
5. Pipelay and fabrication information including welding and coating records
6. Pressure testing and commissioning records
7. Longitudinal, transverse and out-of-straightness profiles
8. Inline and ROV inspections, anomalies and maintenance records

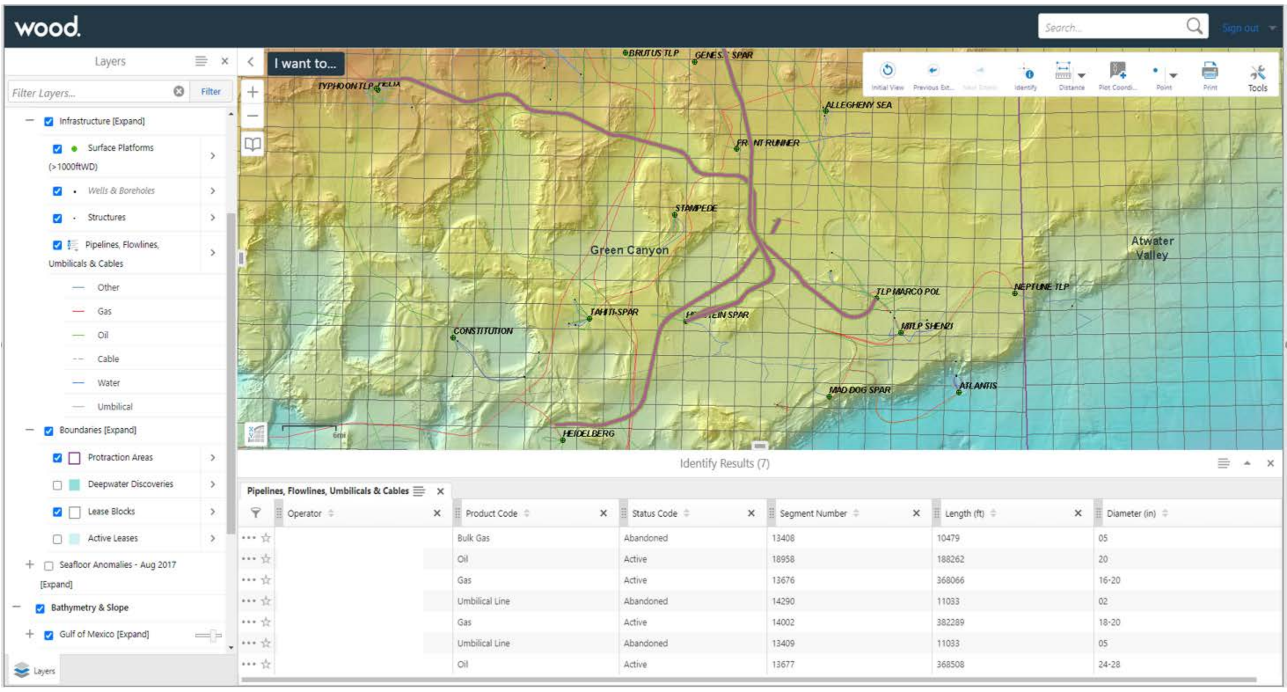

Figure 4-4 Web Based GIS Portal

Such GIS systems can provide a digital DFI record, with links to traditional documents, video and other media for further information. The source of all information is also recorded in the database for audit and verification purposes. Other information can be added through data imports, external database connections, system connections through APIs or live feeds.

In recent years there has been a growing trend of changing ownership / duty holders for operating assets as oil and gas basins mature, with some assets having had multiple changes of ownership / duty holder through their life cycle. During these transitional phases, there is a real potential for loss of data which could be significant in a subsequent life extension assessment. The processes around such transitions, specifically the transfer of all data relating to all lifecycle stages should be carefully managed.

The lessons learned through the life cycle of any project should be captured and taken into account in the next generation concept design. Periodic updates to the codes, standards and shared industry data relating to operational degradation and failure form key routes to capture these industry trends.

The strong guidance herein recommends that operators have a continued focus on risk management / assessment and integrity management through the life cycle, in a robustly documented format, to support the potential for life extension.

4.4 Life Cycle Integrity Management Guidance

This section presents specific SIM guidance broken down into the life-cycle stages as illustrated in Figure 4-2. The guidance is effectively a series of recommendations or assurance activities that, in combination, can ensure all integrity threats may be effectively managed throughout the complete life cycle.

It should be noted that design activities have been split in different levels, to represent typical industry practice for subsea developments. It is acknowledged however, that some of these design phases may be merged or not considered depending on the specific development project. Furthermore, for brownfield developments, the opportunity to implement certain aspect is often not possible given existing constraints or practical limitations. The requirement to demonstrate that the overall SIM system is effective is the responsibility of the system operator.

4.4.1 Feasibility / Concept / FEED

Effective integrity management requires sufficient design assurance and monitoring capability be incorporated into the subsea system prior to detailed engineering. The following aspects should be established or addressed:

- Is concept within existing industry experience? Identify key risks, systems' hazards and mitigations, i.e. location, environment, new technology, design and architecture and forecast lifecycle cost
- Define overall production and operating philosophy
- Define high level reliability, availability and maintainability (RAM) goals and objectives. Perform RAM analysis to provide decision support for concept selection, design optimisation and vendor reliability targets.
- Perform FMECA studies to support RAM and Technology Qualification processes.
- Define high level contractor's capability, implications of technology and different possible system configurations
- Incorporate lessons learned into the design
- Define applicable design specifications and standards
- Define sparing philosophy
- Layout / Access / Installation and Retrieval requirements
- Define requirements for future inspection accessibility
- Requirement for future pigging or line intervention
- Determine process monitoring system and data management system
- Consider redundancy in subsea monitoring equipment
- Consider integrated / built-in monitoring options
- Robust engineering of configuration or layout, ancillary equipment and installation approach
- Define overall Integrity Management Philosophy and Strategy (IMS)
- Use of Qualitative Risk Assessment and design reviews, such as HAZID, HAZOP, barrier analysis
- Define and specify primary safety system and equipment, protective devices and functionality standards
- Define requirements for individual packages to meet overall system goals
- Adopt inherently safe concept as far as practicable
- Tool Life Requirements (i.e. work-over)
- Develop Reliability and Integrity Assurance Document (RIAD), Production Assurance Plan (PAP) and Project Handover Document (PHD).

4.4.2 Detail Design

In the detail design phase, the concept definition should be refined, and suitable operating envelopes established. It is recommended that the following considerations are addressed:

- Statement of requirements, applicable specifications, codes and standards, including life cycle integrity requirements.
- Consider implications of design on every stage of the life cycle of the subsea system, including accessibility for in-service inspection and for decommissioning.
- Detailed operating envelopes, including life-cycle predictions for design, incidental and limiting operating criteria.

- Operational requirements for monitoring of the subsea system within the topsides specifications / interface areas.
- Design load case matrices to assess all life-cycle scenarios e.g. installation, hydrotest, shut-in, and operational extreme cases.
- Perform RAM analysis to provide decision support for design optimisation, to ensure vendor reliability targets are met and sufficiently documented and to provide input to sparing, instrumentation, inspection and maintenance philosophies and plans.
- Cathodic protection and material selection assessment for the field life requirements.
- Depressurisation procedures taking into account material limitations and operational/transient conditions.
- Define design acceptance criteria.
- Assess marine growth coverage based on industry experience.
- Assessment of the range of chemicals treatment (e.g. inhibitors and scavengers) that may be required through the life of the subsea system to ensure material compatibility.
- Assessment of subsea equipment fatigue, and ensure that sufficient attention is paid to coating, finishing, welding, and CP system details.
- Include integrated / built-in monitoring options in design, where selected.
- Refine overall IMS and develop Integrity Management Plan
- Develop Sparing Plan
- Consider allocating an operations/integrity engineer to the design team to ensure operability and inspectability are fully accounted for in design.
- Detailed HAZOP, HAZID
- Detailing of RAM and FMECA
- Establish Operating Limits and Alarm Strategies
- Develop data management system
- Implement MoC
- Assess Operations Resources
- Update Reliability and Integrity Assurance Document (RIAD), Production Assurance Plan (PAP) and Project Handover Document (PHD).

4.4.3 Manufacture, Assembly and Testing

QC/QA plays a critical role in the manufacture of all subsea production equipment. In addition to all design standard requirements, it is recommended that the following points are addressed or performed:

- A detailed manufacturing specification, defining acceptable tolerance limits.
- Review lessons learned from previous projects.
- Quality Assurance and Quality Control of materials purchasing and manufacturing, including identification of critical areas.
- FAT and SIT programme to assess the integrity of critical equipment and components.
- Perform FAT and SIT of all monitoring systems, including integrated / built-in monitoring options.
- Retention of material samples from the manufacturing material batches for future testing.
- Some operators elect to retain manufacturing samples, should they be required for future testing and / or trialling new inspection technologies.
- HAZID review of procedures

4.4.4 Storage

Consideration should be given to the following short and long term storage requirements:

- Consider both short and long term storage / verification requirements ensuring adherence to manufacturer recommendations.
- Consider requirements and conditions regarding covered storage, packaging and periodic inspection and testing or monitoring.
- Consider verification of equipment condition for;
    - short term storage prior to load-out up to ~6 months, i.e. 'as delivered' condition.
    - storage beyond ~6 months, i.e. further verifications may be required
- Protect susceptible equipment and components from direct sunlight or temperature extremes, by use of packaging and covers.
- Ensure that all equipment is handled, protected and secured in accordance with approved guidelines, particularly during assembly, lifting, reeling or trans-spooling operations.
- If wet parking is used, consideration should be given to the integrity threat from both internal and external corrosion, exposure to physical damage, dynamic stability, external protection requirements and, means of recovery/tie-in.

4.4.5 Installation and Commissioning

The installation phase often represents the most significant risk of damaging exposed equipment and components that could result to degradation or other integrity concerns. Key IM considerations for this critical phase include:

- Manage interfaces between supplier and installer (if applicable).
- Complete installation analysis, determine allowable sea states, and competently assess deviations.
- Safe construction and installation procedures
- Consider application of external protective products during the installation phase.
- Review lessons learned from previous projects
- Review technology level of new installation tools, equipment and procedures
- Conduct simulation testing if required
- HAZID of installation issues
- HAZID and HAZOP of commissioning
- Identify any prior (manufacturing) NCRs and highlight to the installation / operations teams.
- Retain records of offshore installation NCRs / concessions / deviations.
- Ensure all operatives are vigilant for evidence of damage and are made aware of the implications of damage.
- Assess suspected damage, repair if possible, ensuring qualified repair technicians and offshore repair procedures are available. Document any repair activities performed.
- Establish Emergency Response and Emergency Preparedness Plans
- Conduct as-built survey of the subsea infrastructure.
- Perform required testing to verify condition of the installed equipment.
- Ensure adequate packing and handling of subsea equipment.
- Perform electrical continuity checks on anodes post-installation.
- Perform Site Acceptance Testing of all monitoring systems, including integrated / built-in monitoring options, where selected.
- Use suitably rated installation equipment e.g. cranes / tensioners / caterpillar tracks.
- Deliver the Commissioning and the Operations Procedures

- Conduct Operations Training
- Installation in accordance with procedures that are 'Approved for Construction'.
- Reference Data (e.g. signatures, actuator performance curves, volumes, pressures, vibrations) to be used for later in life comparisons

4.4.6 Project Handover to Operations

This phase is a significant milestone in any project, requiring careful interface management with respect to:

- Project transfer of a subsea system IMS, which is supported and implemented by operations.
- Handover of completed as-built documentation, including baseline inspection data.
- Handover of system verification / assurance process and compliance with legislation.
- Establish and agree operational envelopes (e.g. pressure, temperature, offset etc) to be adopted.
- Verify integrity test results as part of the formal handover.

4.4.7 Operation

Implement, maintain, review and audit at regular intervals an integrity management strategy for the subsea system which includes all equipment and details boundaries of integrity responsibility and interfaces.

- Actively implement and maintain an Integrity Management System.
- Implement, measure, and assess agreed operational envelopes (e.g. pressure, temperature, offset etc.) - in case of modifications to the system, peer review risks.
- Implement Operations Procedures, Maintenance strategies and procedures, Spares strategies and plans, Inventory management / Preservation, Obsolescence, Surveillance, Management of Change, Anomaly Management Databases, Anomaly Criteria, Risk Based Inspection and Maintenance
- Review lessons learned from previous projects.
- Utilise industry databases to understand both how subsea systems can (and have) degraded in service and the latest industry guidance relating to inspection and monitoring.
- Monitor and log data from of all monitoring systems in line with integrity strategy, including integrated / built-in monitoring options, where selected.
- Evaluate how procedural control can be used to prevent errors that can affect system's performance after manufacture. This also includes measuring and maintaining actual performance and collecting information to improve future projects.
- Use of bow-ties to illustrate the overall risk management.
- Establish alarm limits for key parameters and assess excursions.
- Establish Emergency Response and Emergency Preparedness Plans
- Re-assess availability goals for new production targets
- Verify compatibility of any inhibition and treatment fluids prior to use, if required.
- Assess any planned intervention on the subsea infrastructure which has the potential to adversely affect the subsea asset integrity.
- Implement material coupon sampling programme for high risk elements.
- Record and compare actual environmental conditions against design limits.
- Repair any site of damage, assess implications, and consider engaging the equipment manufacturer.

4.4.8 Lifetime Extension

A life extension assessment is performed when the operating period approaches the original design life. Key considerations are as follows:

- Assess current integrity based on known inspection, monitoring, and testing records through the life of the subsea system including ancillary components which form part of the system.
- Assess future integrity threats / risks, considering the known condition and taking into account industry available damage and failure statistics which are relevant to the subsea system under consideration.
- Where feasible, apply industry developed degradation models.
- Identify any repairs / modifications / further assessments that are required to ensure integrity through extended life.
- Review the current in-place integrity management program (inspection, monitoring, testing), and assess its suitability to mitigate threats in extended life.

See also section 9.0 Lifetime Extension.

4.4.9 Decommission

- Review lessons learned from previous projects
- Consider plans for further use / potential re-use prior to developing a recovery plan e.g. care of handling approach may vary depending on whether there are plans for re-use.
- HAZID of decommissioning activities
- Establish Emergency Response and Emergency Preparedness Plans
- If cutting is used during recovery, care should be given to rigging of cut ends. Lifting and handling aids have a risk of slipping creating a potential dropped object; use of a temporary pulling head may be required.

4.4.10 Historical Data

Potential exists at end of operating life to selectively establish equipment integrity and condition, thereby closing the loop on life-cycle integrity management.

- Gather and collate data relating to every significant stage of a subsea system life cycle, which may be useful learning for the next generation concepts and designs.
- Actively support the industry aspirations of continuous improvement, extension of capabilities, and improved reliability through gathering and sharing of industry experience.

4.5 Inspection and Maintenance

A key aspect of integrity management is the ongoing close management of risk. Consistent with commonly used standards for subsea risers [12], and pipelines [13], there are key three components to consider:

- A deep understanding of credible threats, including those that may not have been witnessed in the history of the operation so far but could become credible in the future.
- The potential consequences of failures due to these threats.
- The health of the barriers that work to reduce both the probability of occurrence of these threats in the first instance and those barriers that work to reduce the consequence of failure after failure has occurred.

Inspection is an activity to acquire the physical condition of a subsea asset, the result of such information is used to reduce the uncertainty of the integrity of the asset and as an initiator for further integrity analysis i.e. inspection to identify anomalies differing from original designs assumptions and requirements. Risk based inspection (RBI) will allow the asset operator and owner to prioritise resources towards assets that carry the most risk if they were to fail.

Whilst there are a range of risk assessment processes, an evidence-based approach should be used to screen out threat categories which are not relevant to the specific subsea asset. This avoids in-depth focus and assessment of threats which can be qualitatively assessed. Risk can be evaluated qualitatively (expert judgement) and/or quantitatively (i.e. calculations / modelling), depending on availability of input data, and feasibility / cost efficiency. RBI should be carried out for all elements of the subsea installations.

Risk-Based Inspection (RBI) will be used as a key decision-making technique for inspection planning. Risk comprises the Consequence of Failure (CoF) and the Probability of Failure (PoF). It is a formal approach designed to aid the development of an optimised inspection regime, and the evaluation should be carried out according to Operator risk matrixes and methodology.

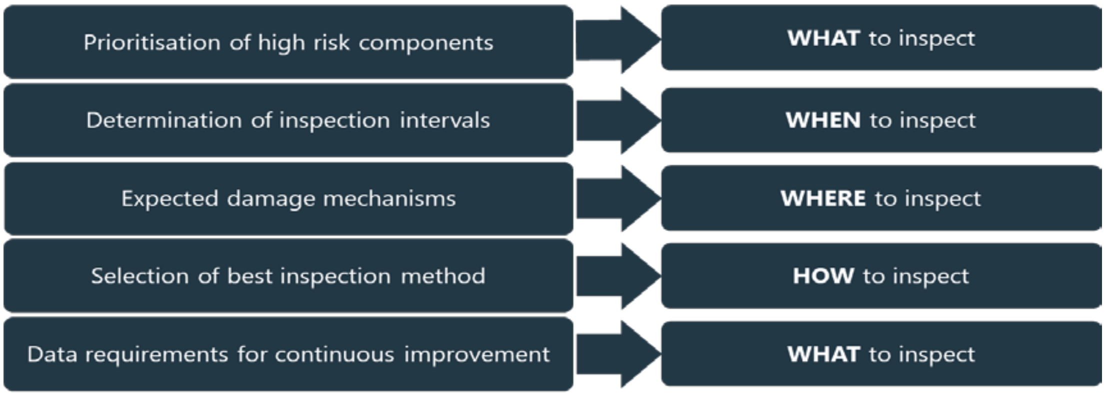

Figure 4-5 Deliverables of an RBI assessment to the inspection program [14]

The adoption of a Risk Based Inspection strategy is a recognised method of enacting integrity management. A properly applied RBI process provides the necessary focus on credible threats and barrier health, the mode of failure and hence the consequence of failure. The risk report generated from an RBI assessment then in turn informs a bespoke inspection and maintenance program for the asset, targeted at the identified asset specific threats. Regular review and update of the RBI assessment as new information is acquired ensures the inspection and maintenance program remains effective throughout the life of the assets. This is often termed a 'Performance Improvement Cycle' as it is an ongoing, near continuous refinement of integrity management.

As well as the input to generated inspection and maintenance program, RBI also provides a detailed risk report that can be used to communicate asset health to senior management and allow risk-based conversations on e.g. intervention plans, expenditure, end of life planning, to name but a few.

4.6 Management of Change

The primary objective of a Management of Change (MoC) process is to ensure that sufficient rigor is applied in terms of planning, assessment, documentation, implementation and monitoring of changes affecting and installation or operation so that any potentially adverse effects on asset integrity are identified and managed effectively to mitigate adverse effects.

The asset management organisation plays a key role in ensuring that all changes are communicated and managed in a systematic manner and that all required stake holders are aware of the changes and approval of changes is known. Changes should be consistently recorded and assessed in terms of the life cycle of the asset.

4.7 HSE and Emergency Response

The ALARP (As Low As Reasonable Practicable) principle should be observed in day to day asset management activities. The asset management plan should also address a number of potential emergency situations, incidents and associated repairs as part of emergency response plans.

Reference is made to PSA management regulation §§4 and 23 stating requirements for risk reduction and continuous improvement [15].

4.8 Lessons Learned

Lessons learned from assurance activities or from incidents should be captured and communicated within the operator's organisation and across the wider industry as necessary (i.e. in accordance with the ALARP principle).

4.9 Incidents, Preventive and Corrective Actions Management System

Arrangements should be in place to ensure that all relevant preventive and corrective improvement actions arising from monitoring, audit and review are recorded, documented and tracked to closure.

For incidents; their investigation, root cause identification and the resulting action must also be recorded for continuous improvement purposes.

Reference is made to PSA management regulation §20 stating requirements for registration, review and investigation of hazard and accident situations and §22 stating requirements for handling of nonconformities.

4.10 Performance Evaluation

Asset performance should be measured, analysed and evaluated. Key Performance Indicators (KPI) provides the basis to review the effectiveness of the asset management system and process and ultimately the adjustment of mitigation and / or monitoring activities. KPI's are often used to give a high level status of an asset when measured against defined criteria.

A set of performance / target level of service measures should be developed to monitor the effectiveness of implementation of the asset management. Target and acceptance criteria should be defined for each asset.

Reference is made to PSA management regulation §19 stating requirements for collection, processing and use of data, and PSA activity regulation §49 stating requirements for evaluation of maintenance effectiveness.

4.11 Monitoring, Audit and Review

Operators should have monitoring, audit and review arrangements in place. This is to ensure that the asset management plan is delivering according to objectives and performance. The audits should be conducted by both internal and external parties.

Audits focus on procedural compliance with respect to objectives, policies and requirements defined by stakeholders. Audit plans and procedures shall be developed and maintained by the operator and asset management team.

Audit records should be kept and resulting actions should be added to the action management system to ensure they are tracked, managed and suitably closed out.

Reference is made to PSA framework regulation §19 stating requirements for verifications and management regulations §§19-23 for requirements related to follow-up and improvement.

4.12 Risk Analyses

Operators should carry out risk analyses to establish a comprehensive picture of risk associated with operation of the subsea system, including identification of hazards, potential accident situations and initiating incidents with a potential for major accident risk.

Appropriate risk analyses and tools must form part of the decision basis for definition of safety barriers, functions and related performance standards.

Reference is made to PSA management regulation §17 stating requirements for risk analyses and emergency preparedness assessments.

NORSOK S-001 and related safety standards are outside the scope for this guideline and are therefore not covered in any detail herein.

4.13 Reliability (RAM) Studies

RAM analysis and associated activities such as FMEA/FMECA are examples of tools used for risk assessment from concept through detail design and into operations. The outcome of a RAM analysis may form part of the decision basis for options selection, system and equipment configuration, e.g. internal redundancies and provide input to sparing philosophy, equipment critically classification, inspection and maintenance strategies and asset integrity management plans.

For implementation of Reliability, Availability and Maintainability studies, ISO 20185 [16] for topside systems, the associated API RP 17N [17] for subsea systems and ISO14224 [18] for failure data gathering should be referred to.

4.14 Competence Management System

The main objective of a competence management system is to ensure the personnel with the appropriate competencies perform and check the work to be performed for a given activity as part of a project or asset integrity management team.

Upon project initiation, the project manager reviews the competence requirements of personnel responsible for delivering and checking work for specific activities and tasks. In addition, all personnel should have a personal responsibility to understand;

- the competencies to which they have been assigned,
- the levels that those competencies have been assigned, and
- how those competencies correspond to the scope being delivered.

Furthermore, it should be the personal responsibility of everyone to act within the areas of their competence. Personnel should be aware of the limits of their competence, and notify their project manager / line manager / senior management (as appropriate) if they believe there is a weakness or gap in the competency or experience of the team deployed to deliver a project or activity. In such situations, a peer review or assist process can be applied to engage suitable Subject Matter Experts across the organisation to mitigate any gap or weakness identified.

The competency management system should comply with relevant international standards, i.e. ISO9001 [19] and / or ISO17020 [20] for inspection management. Good practice elements include;

- The competence criteria should be defined i.e. for a specific competence the criteria for assessment to a specific level of authority should be defined. Because someone has "performed" something in the past does not necessarily demonstrate they did it in a competent way.
- Specific competence assessments should be performed by personnel who are technical experts (SMEs), taking cognisance that a line manager is not always the technical expert for every technical activity delivered by every individual in their team.
- Competence management systems should be traceable and accessible for personnel who need to demonstrate system assurance.

Reference is made to PSA framework regulation §14 and activity regulation §21 stating manning and competence requirements.

4.14.1 Human Factors

Some of the larger accidents in the energy industry (nuclear, oil, gas, electricity and mining) have had human error as the main contributor [21]. Human factor is interrelated to system reliability by studying the implications and effects of human action in the performance of the process, which is closely linked with the culture, formal education, values, ethics and social responsibility, skills, leadership and experience, and physical and mental condition of every individual. Biases such as confirmation bias based on experience, or situations, not exactly the same as what has been experienced as successful in previous situations may be a source of misunderstandings, misinterpretation and inappropriate response [22]. Formal frameworks for competence management, and definition of roles and responsibilities helps to limit such risks by:

- Analysis of work environment design and configuration with a focus on e.g. human machine interface (HMI), noise, ventilation systems and ergonomics.
- Review of procedures for training to avoid any weaknesses or errors that may affect the possibility for the person in charge to operate safely, within the frames of work scope and assigned responsibilities.

Reference is made to PSA activity regulation §23 stating training and drills requirements.

4.15 Organisational Interfaces

Operator organisations may have a range of discipline teams that are responsible for managing and maintaining specific subsea systems, typically organised as below:

- Platform/FPSO/Marine facilities
- Subsea facilities
- Well facilities
- Sub-surface / reservoir performance

It is paramount that each section has one vision and shared responsibilities for managing and maintaining subsea asset integrity. A Subsea IM organisational chart should be created to reflect the interactions between team members and stakeholders, including relevant discipline leads who can identify potential issues that could influence the IM outcome. Each person or group's role and the specific needs and areas of expertise should be clearly specified. Roles and responsibilities for all parties involved in the response to an emergency should be established including clear lines of communication. Interfaces across sections, both structural and functional, should be clearly defined. Integrity roles and responsibilities shall be defined and communicated through the organisation. Integrity personnel should be independent and have an unbiased decision-making ability. The personnel carrying out well integrity assessments shall be independent of the Drilling and well Production Management teams.

Additionally, the organisational interfaces between project delivery / installation and operations teams need to be carefully managed to ensure that project delivery take into account the full life-cycle implications of any design / fabrication / installation decisions. Careful organisational management of the commissioning / handover stages of a project to operations are also essential to ensure all data is transferred and the required monitoring / testing systems are in place for the new systems.

Where organisations have a team of technical authorities with responsibility for technical integrity, which is separate from, and with differing reporting lines to the operations teams, the interfaces must be carefully managed. Whilst the technical authorities decision making processes should be independent and un-impeded by operational issues, they should retain the ability to ensure that operations teams implement the required processes / monitoring / maintenance when required to ensure integrity is maintained.

To provide an overview of the key tasks supporting the Asset Integrity Management System, a RACI chart could be implemented. This chart will show how IM activities are resourced and managed and identify the person(s) accountable for each task or key area. A RACI chart can serve as an important tool to clarify roles, responsibilities and associated expectation and contribute to effective communication. It may force the organisation to reflect and take action to close potential gaps identified and clarifies control of processes to the organisation. An example of a RACI chart is given in Figure 4-6. The chart is only intended to provide an overview of position responsibilities, not as the primary means of defining roles and responsibilities.

Reference is made to PSA management regulation §§4 and 6 stating requirements for risk reduction and management of health, safety and environment.

ACTIVITY \ ROLE	Offshore Installation Manager	Production Supervisor	Marine Operations Manager	Subsea Asset Manager	Subsea Integrity TA	(...) Roles defined according to organisation
Plan Subsea Survey and Inspection			C	A	R	
Plan Safety Operating Envelope Monitoring		C		A	R	
Carry out Subsea Survey and Inspection	C		R/A	I	C	
Take and Analyze Production Fluid and Solid Sample	A	R		I	C	
Monitor and Analyze Safety Operating Envelope Parameters	A	R		I	C	
Review Subsea Survey and Inspection Report				I	R/A	
Perform Subsea Asset Repair	C		R/A	C	C	
Perform Subsea Integrity Status Review	I		I	A	R	
(...) Activities defined according to IM program for specific asset						

R: Responsible A: Accountable C: Consulted I: Informed

Figure 4-6 Example RACI Chart

For implementation of a RACI chart, asset specifics e.g. size of organisation and complexity of asset and activities need to be considered. The same individual may cover several roles, but care should then be taken to avoid that the same individual can be put in a conflict of interest of e.g. safety or emergency response versus optimisation of day to day revenue or cost. The example above is intended to be descriptive, not prescriptive.

Potential organisational gaps are summarised in Table 4-1;

Table 4-1 Organisational Interfaces and Summary of Potential Gaps

Organisation Interfaces	**Potential Gap**
Operation Organisation Interfaces	Operator organisations are typically split into section that are responsible for overall subsea asset integrity i.e. marine, well, and subsea section with specific roles, responsibilities, and expertise. Coordination and supervision across sections should be defined to ensure that the IM system is effective. There is a need for routine validation and challenge of the integrity management process to provide assurance that it is effective. This should be conducted by a part of the operating organisation that is not directly involved with the day to day integrity management cycle.
Projects and Operations Interfaces	Larger operator organisations typically have separate operations and project/development teams. Lessons learned and operational knowledge from existing assets should be made available, communicated and referenced as essential input for the project.
Transfer of Ownership	Variability of organisation and integrity requirement between operators. The processes of data transfer should be carefully managed during transitional phases of ownership. Loss of data represents a risk to effective IM and will negatively impact the suitability or confidence for lifetime extension.
Different ownership and operatorship in one system	Variability of organisation and integrity requirement between operators. While a development may have been developed and operated by a centralised organisation, there is a growing trend where new owners contract out duty holder responsibility to a third party. Such contracted duty holdership agreements need to ensure clear division or battery limits of ownership with respect to subsea equipment.
Human Resources	Retention of corporate knowledge / expertise may be a challenge in the future for ageing assets, particularly when subject to change of ownership. Therefore, succession planning, in combination with maintenance of SIM life-cycle documentation, should be a priority for operators of ageing subsea infrastructure.
Knowledge Sharing	Detailed knowledge and lessons learned sharing across subsea system fabricator, installations, operators, regulators may be limited due to, commercial impact, contract requirements, intellectual properties and patents, company reputation, and commercial competitiveness.

4.16 Technical Interfaces

The hydrocarbon transport chain system between wellhead and riser ESDV is typically categorised as a number of different asset groups. The typical asset grouping in the hydrocarbon chain system, categorised by main asset groups, equipment and sub-components are presented below in Table 4-2, based on SURF IM JIP [21]. Managing and maintaining integrity of a subsea system is not only reliant on the main integrity groups by themselves, but the technical interfaces between sub-asset groups and ancillary equipment are also crucial to make sure there is no weak link in the chain.

The management of technical interfaces at the boundaries of the subsea systems are also of critical importance to the overall integrity management of an installation and need careful and active management. Operators need to ensure that the responsibilities for performing and reporting on integrity driven maintenance and testing activities are clearly documented and understood by all stakeholders, operating and integrity management team members.

At the "facility / ESDV end" of the system, challenges which are known to have occurred in the past relating to interface management, reporting, and responsibility for taking action based on the results, include;

- ESDV testing / management
- Topsides pipework boundaries / interfaces
- Structural steel supports / clamps for risers / caissons
- Riser hang-off clamps / mechanisms, including bend stiffener systems and dis-connectable buoy interfaces where relevant in flexible pipe applications
- Annulus venting for flexible pipe (ensuring vents are connected, and venting controlled / managed suitably)
- Monitoring systems on the topside facilities which have the potential to impact subsea integrity in a beneficial or adverse way, either directly (specific riser monitoring systems) or indirectly (upstream / downstream process monitoring)

At the "wellhead end" of the system, the following areas should be confirmed for similar interface management should be included;

- Monitoring systems from downhole sensors, which have the potential to impact subsea integrity in a beneficial or adverse way, either directly or indirectly
- Reservoir performance characteristics with the potential to impact integrity e.g. souring, solids breakthrough, or other changes in fluid characteristics / conditions

Finally, the interfaces between product systems should be defined, and closely managed. Whilst the subsea system is often shown on a single "linear" path between the subsea wellhead and the topsides ESDV (e.g. as shown in Figure 1-1), the reality is rarely as simple. There are a number of interdependencies which must be managed within not only a single product stream being considered, but across other product systems, which makes most subsea systems more complicated in their physical configuration and operational interdependencies. Interfaces and interdependencies which should be managed in this context include;

- The configuration of the hydrocarbon production system which may configure a large number of producing wells through a complicated system of manifolds and sub / splitter manifolds to a range of different flowlines and risers to optimise operations based on specific (and time-varying) reservoir performance
- The potential to cross over / link (higher pressure) gas lift / umbilical / control systems into production systems (often with lower operating / design pressure) through bypass lines at manifolds / wellheads

- The separation / barriers / controls between different pressure systems on the same conveyed product e.g. gas export / lift / injection / disposal

Active management of the pressure boundaries and control architecture around High-Integrity Pressure Protection Systems (HIPPS), particularly when the system architecture is re-configured and / or elements uprated /downrated

- Material / system compatibility relating to the transfer of bore properties / contaminants from produced water into water injection systems

Table 4-2 Subsea Asset Grouping

<table>
<tr><th>Integrity Group</th><th>Equipment</th><th>Sub-component</th></tr>
<tr><td rowspan="4">Xmas Tree / Wellhead</td><td>Xmas Tree (HXT&VXT)</td><td>Structural Steel Frame, Bore piping, Annulus, and Production Valves, Subsea Accumulators, SCSSV, Connectors, Chemical Injections and Hydraulic Couplings, Wellhead Connectors, Debris Caps, Tree Caps, ROV Panel, Tubing Hanger, Instrumentations, communication equipment</td></tr>
<tr><td>Interface Upward</td><td>Choke MPFM, Connector, Subsea Control Module</td></tr>
<tr><td>Interface Downward</td><td>SCSSV, Downhole smart well hardware, downhole instrumentation</td></tr>
<tr><td>Wellhead</td><td>Hydraulic Tieback Connectors, Conductor, Low- and high-pressure housings, Surface, Intermediate, Production Casings/Liners, Hangers and Seal assemblies, Wellhead valves</td></tr>
<tr><td rowspan="3">Flexible Pipeline</td><td>Static Jumpers
Static Flowlines</td><td>Piping layers (carcass, internal pressure sheath, tensile armor wires, pressure armor wires, external sheath)
Piping Connectors (End-fittings, flanges, connectors)</td></tr>
<tr><td>Ancillary Equipment</td><td>Bend Restrictor, Hold Back System, Tethers, Support Structure, Pile Base, CP systems</td></tr>
<tr><td>Interface</td><td>Interfacing connectors / structures / manifolds
Pig launchers / receivers</td></tr>
<tr><td rowspan="2">Rigid Pipeline</td><td>Jumpers and spools
Flowlines
Water/Gas/Chemical Injection
Transport/Export</td><td>Pipeline inline components (valves, tees, wyes, piggyback supports)
Piping segments, bends</td></tr>
<tr><td>Interface</td><td>Pipe Connectors (flanges / seals / studs / nuts, Collet hub & segments, Clamp hub & segments)
Pipe coatings (anti-corrosion, thermal insulation, self-weight)
CP systems (anodes, impressed current)
Pig Launcher / Receiver</td></tr>
<tr><td rowspan="4">Rigid Riser</td><td>Steel Pipe</td><td>Steel Line Segments, Insulation/Coating, Caisson enclosures</td></tr>
<tr><td>Ancillary Equipment</td><td>Structural Support Clamps, Riser Anodes, Impressed Current CP</td></tr>
<tr><td>Topside Interface</td><td>Isolation Valve / Riser ESDV,
Dead Weight / Hang-off support</td></tr>
<tr><td>Subsea tie-in</td><td>Tie-in flange / mechanical connector, SSIV structure tie-in</td></tr>
<tr><td rowspan="4">Flexible Riser</td><td>Topside Interface</td><td>Isolation or emergency shut down valve
Pig launchers / receivers
Riser annulus venting arrangement
Riser end fitting hang-off arrangement
I-tube to bend stiffener connector interface
Bend stiffener connection systems
Dis-connectable turret buoy (if applicable)</td></tr>
<tr><td>Dynamic Risers</td><td>Piping layers (carcass, internal pressure sheath, tensile armour wires, pressure armour wires, external sheath)
Piping Connectors (End-fittings, flanges, connectors)</td></tr>
<tr><td>Ancillary Equipment</td><td>Bend Stiffener, Bend Restrictor, Buoyancy Modules, Mid Water Arch, Clamps, Hold Back System, Tethers, Support Structure, Pile Base, Riser Base, CP systems</td></tr>
<tr><td>Subsea Interface</td><td>Flanges, Connectors / inline structures
Pig launchers / receivers</td></tr>
</table>

5.0 Standards Review

In order to manage the integrity of any system, including those in the subsea environment addressed in this report, it is essential to utilise the lessons learned by the collective industry which are incorporated within industry guidance, codes and standards. It is also important for system operators to engage with the industry standards organisations and other bodies to continue to share new lessons for the collective benefit of the industry, both within the region and globally, to mitigate major accident hazards.

It is important from a system wide SIM perspective to establish relative design margins across the individual components / asset groups. This requires an appreciation of the various design approaches and internal pressure definitions and how these have evolved over time (for example, API Specification 6A for wellhead and tree equipment is currently in the 24th edition).

In general terms, subsea equipment is designed using limit state methods, mainly based on stress utilisation, however strain or deflection may be used for non-metallic sub-components. Internal pressure definitions have over time sought to become more aligned, although the terminology used is still nuanced by particular component as illustrated in Figure 5-1 below. By contrast to pipeline design standards, more complicated multi-component wellhead or valve equipment is more standardised, e.g. the valve design codes reference in section 5.3 below cover only seven 'working pressure' classes. The differing design approaches, failure modes and standards therefore require specialist discipline input to determine and clearly communicate respective component risks within the overall system.

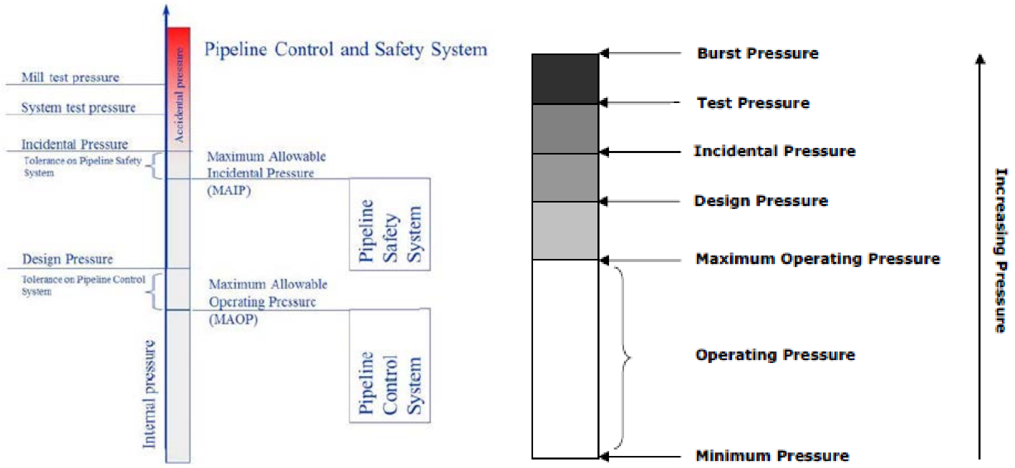

Figure 5-1 Internal pressure definitions for rigid (left [23]) and flexible (right [24]) pipeline

Operators should also maintain their awareness of the relevant standards as they develop through the life-cycle of their subsea system, from early design phases through to life extension and decommissioning, and consider the effect of changes in the guidance / codes / standards on their specific operating systems. A more formal / structured review relating to the implications of changes in such industry frameworks is normally a requirement during the life extension phase.

The key design standards are listed, by asset integrity group, in Appendix B. General requirements and an overall listing of the key normative design references for subsea production systems is listed in [25]. Specific guidance relating to the integrity management of asset groupings are described in the following sub-sections.

5.1 Subsea Pipelines, Rigid Risers and Connection Systems

For rigid pipelines and risers there are a number of standards and recommended practices available for the design, fabrication, testing and operation of pipelines. These have been predominantly developed from oil and gas industry experience gained in North America and the North Sea to initially benefit operations within these geographical areas. Over time and with the growth of the oil and gas industry worldwide, the use of these national standards has grown, and they are now typically used by projects and operations globally. The organisations responsible for the development of the main body of codes and standards are;

- The American Petroleum Industry (API)
- American Society of Mechanical Engineers (ASME)
- The British Standards Institute (BSI)
- International Organization for Standardization (ISO)
- Det Norsk Veritas (DNV GL)
- NORSOK

For rigid pipeline design, operation etc. the most commonly referenced codes are;

- ASME B31.4 (oil pipelines) & B31.8 (gas pipelines)
- BSI PD 8010 (part 2)
- DNVGL-ST-F101
- API RP 1111

These design codes are supplemented by a large number of other related codes, standards and recommended practices that provide operators with further guidance on specific rigid pipeline design and operation with the main aim of ensuring safe and reliable operation.

The long-term integrity of rigid pipeline systems cannot be assured by good design and fabrication alone and the concept of ongoing pipeline integrity management has been developed and codified to assist operators in this (ref. section 4.1). Current key codes and practices for rigid pipeline integrity management are listed in Appendix B These generally follow the same principal for integrity management with the emphasis on assessment of credible threats to the operation of a pipeline, the consequences of failure should the pipeline leak, the classification of risk and then a set of mitigative actions to reduce risk to tolerable levels. This process is repeated to ensure risk is correctly classified the actions taken to reduce it are appropriate.

5.2 Flexible Pipe Risers & Flowlines

The primary standards in relation to flexible pipe system design and operation are API specification 17J [24] and API recommended practice 17B [26] respectively. General requirements for IM are described in Section 11 of 17B and a flowchart of the overall process is presented in Figure 24. It should be noted that the process is generic to a range of equipment and includes the following key stages:

- Failure mode identification and risk assessment
- Development of an IM strategy that sets out the required integrity measures
- Periodic review of the implemented strategy and preparation of fitness for purpose statement

In addition, it should be noted that a number of additional guidance documents relating to flexible pipe IM have been developed to support operators. These sources capture a range of integrity experience and learnings from flexible pipe operation and are listed below.

- Riser Integrity Management, [12]
- Handbook on Design and Operation of Flexible Pipes, [27]
- Flexible Pipe Integrity Management Guidance & Good Practice, Sureflex [9]

Flexible pipe systems routinely include a range of bespoke ancillary equipment to support the pipe during installation and operation, and it is important that the IM strategy includes these components in addition to the pipe itself. The associated design requirements for these items are as follows:

- API Spec 17L1, Specification for Flexible Pipe Ancillary Equipment, [28]
- API RP 17L2, Recommended Practice for Flexible Pipe Ancillary Equipment, [29]

Finally, industry guidance in terms of lifetime extension requirements and experience have also been developed to assist safe operations. Key references include the following:

- Lifetime extension for subsea systems, NORSOK U-009 and NORSOK Y-002
- Guidance for Life Extension of Unbonded Flexible Pipe Systems, [30]

5.3 Valves

The primary standards in relation to pipeline valves design and operation are API and ASME specifications 6A, Specification for Wellhead and Christmas Tree Equipment, 6D Specification for Pipeline and Piping Valves , 6DSS Specification for Subsea Pipeline Valves and 17D Design and Operation of Subsea Production Systems – Subsea Wellhead and Tree Equipment, ASME B16.34 Valves Flanged Threaded and Welded End.

There are several standards and recommended practices available for the design, manufacture, testing, and operation of pipeline Valves. Like the pipeline standards, these have been predominantly developed from oil and gas industry experience gained in North America and North Sea, and now widely applied elsewhere. Over time and with the growth of the oil and gas industry worldwide, the use of these national standards has grown, and they are now typically used by projects and operations globally.

These design codes are supplemented by many other related codes, standards and recommended practices that provide operators with further guidance on specific pipeline valve design and operation with the main aim of ensuring safe and reliable operation.

5.4 XMTs/Wellheads

The main standards in relation to XMT/Wellhead systems design and operation are API Spec 17D - Design and Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment (ISO 13628-4), 2nd edition: 1 May 2011 and API Specification 6A, Specification for Wellhead and Tree Equipment, 21st Edition, November 2018 (Effective Date: November 2019). XMT/Wellhead systems include valves which are mainly governed by these standards below. These include:

- API Spec 14A Specification for Subsurface Safety Valve Equipment (ISO 10432), 12th edition: 2015.
- API RP 14B Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Sixth Edition, (2015)

- API Std 6AV2 Installation, maintenance and repair of safety valves. 2nd Edition: August 2020
- API Std 598 Valve inspection and testing, 10th Edition: 1 October 2016.

General requirements for IM are described in international standards like NORSOK D-010, NORSOK U-001 and ISO 16530-1. NORSOK D-010 standard focuses on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities and operations. ISO 16530-1 document is intended to assist the petroleum and natural gas industry to effectively manage well integrity during the well life cycle by providing:

- Minimum requirements to ensure management of well integrity
- Recommendations and techniques that well operators can apply in a scalable manner based on a well's specific risk characteristics.

Country specific regulations or Code of practices also exist in countries like Malaysia, Abu Dhabi, Brazil, UK etc.

6.0 Threats Assessment

6.1 Background

In order to prevent hydrocarbon leakage, threats to barriers need to be understood so they can be managed, and underlying failure mechanisms monitored with appropriate action being taken to maintain barrier integrity. As part of the preparation of this guideline, the study team has sought to identify and summarise main known threats to pressure containment and primary protection in a subsea hydrocarbon pressure containment system.

For the purpose of this guideline, "consequence side" of the risk assessment has been "locked" to only consider the loss of pressure containment. The assessment is therefore focused on unmitigated probability for respective threats and failure modes with a potential to cause barrier failure in the respective systems, disciplines and interfaces of the subsea hydrocarbon containment flow path. Wellhead, valves, rigid and flexible pipelines and risers are specifically covered with separate unmitigated probability rankings and a focus on main equipment types and key risk areas. It is in the nature of the assessment that it is based on the experience of the review team and generic, meaning any findings presented in Table A 1 (Appendix A) should not be applied directly to any specific asset, but may function as a starting point and check list for identification and definition of key risk areas for a subsea system. Observability and Consequence (Magnitude and Location) columns are populated for threats with high unmitigated probability ranking only. Separate columns are included to capture key organisational, operational and technical interfaces for each threat, but any specific assets and organisation will need to identify and address key interfaces and associated risks and barrier threats relevant to their operation.

6.2 Methodology

The following subsections introduce and summarise the approach taken in developing the generic threats and columns presented in Table A 1 (Appendix A).

6.2.1 Threats

The threats approach utilises guidewords (or failure drivers) to identify and categorize potential failure initiators. The following failure drivers have been identified for subsea systems.

1. Internal Corrosion;
2. Erosion;
3. External Corrosion;
4. Fatigue;
5. Flow Assurance/ Flow Restriction;
6. Service Loads;
7. Temperature;
8. Pressure;
9. Accidental Damage;
10. Manufacturing / Quality;
11. Installation.

Note that the list is not exhaustive not all of the above failure drivers are applicable for any given component.

6.2.2 Barrier Threats Identification

Failure is defined as the combination of the following elements:

1. Failure Mode: Effect by which a failure is observed on the failed item; (e.g. pressure induced collapse);

2. Failure Cause/Initiator: Circumstances associated with design, manufacture, installation, use and maintenance, which have led to a failure (e.g. Pressure exceeding BOD);
3. Failure Mechanism: Sequence of stages leading to a failure.

The Failure Modes lists, though not exhaustive, are intended to include the most likely sources for subsea system failure. A systematic HAZID process may be necessary to identify any additional Failure Modes to which a specific subsea system may be exposed for a specific intended application.

Failure Result:

The ultimate impact of a component failure. Failure results can be categorized by types of impact, Hydrocarbon Loss of Containment and Loss of Operability.

The loss of operability of some sub-components does not imply safe production cannot be maintained (e.g. loss of sensor function). However, it is likely that the system will experience possible loss of production efficiency, potential costs associated with intervention to restore the system's functionality, and a possible increase in risk due to increased uncertainty in monitored data.

For the purpose of this guideline, only Hydrocarbon Loss of Containment is considered. This means the consequence side of the risk assessment is "locked" except the review team has sought to differentiate on potential magnitude and location of leak.

6.2.3 Records of Occurrence

Usually qualitative or quantitative approaches are used to determine probability of failure. Records of occurrence are identified, as follows:

1. No records;
2. Anecdotal;
3. Happened to operators.

6.2.4 Detection and Observation

Main methods of inspection and monitoring for failure mechanism and cause of barrier threat are summarised in Table 7-1 and listed for each identified threat.

The data quality acquired from the applied inspection and monitoring methods and tools should be assessed and documented as part of a risk assessment. For the generic unmitigated threat probability assessment given in Appendix A, no specific asset has been analysed and the expert judgement applied may be categorised as general, non-specific knowledge. For application to a particular subsea installation, specific knowledge for the asset should be applied, and further the data available as input to the threat and risk assessment may be categorised as weak, medium or strong depending on the quality of data gathering and documentation [31].

6.2.5 Highest Observation Accuracy

Ranking of highest observation accuracy based on methods listed under the detection and observation column in Appendix A.

Accuracy can be categorised by:

Accuracy	Description
Accurate	Failure mechanism directly observable by e.g. visual inspection or continuous monitoring.
Analysis Required	Failure mechanism only observable through post processing of monitoring or inspection data e.g. ILI post processing data for internal corrosion.
Low	Failure mechanism cannot be observed due to physical obstacles or the modes of failure e.g. crack inside buried pipelines.

6.2.6 Consequence

For each failure mode the consequence impact should be assessed and identified for a typical system.

It is acknowledged that because no thresholds have been identified for the severity of consequence, the approach is subjective; but as a guidance tool, the seep, pinhole, leak and rupture -ranking system has been adopted; e.g. the rupture/collapse of a pipeline leads to a loss of containment of hydrocarbons which causes a medium to high environmental consequence as the leak is controlled by Underwater Safety Valve (USV) closure; however, the operator will face a high cost consequence because of replacement/ intervention needed and also potentially severe HSE and reputational consequences.

6.2.7 Location

The location column in the Appendix A unmitigated threat probability assessment is included to differentiate between threats to barriers with a potential for loss of hydrocarbon containment inside vs outside the 500 meter platform safety zone.

6.2.8 Unmitigated Probability Assessment

Probability Rating	Description
H	High
M	Medium
L	Low
NA	Not Applicable

6.2.9 Key Organisational Interface Risk Area

Organisation element interfaces that have responsibilities for the asset with an impact on barrier health during asset lifecycle phases. This column states the key typical organisation interfaces requiring stakeholder focus and attention.

6.2.10 Key Operational Interface Risk Area

As per Table 4-1, key operational interfaces with an impact on barrier health through asset lifecycle phases.

6.2.11 Key Technical Interface Risk Area

Main equipment and component interfaces where the risk is applicable. If the risk is stated for several assets, then the risk will also be applicable for the interface between the given assets. This includes system interdependencies to support systems, e.g. control systems, injection systems, etc. The risk assignments are qualitative based on the experience-based input from discipline experts.

6.3 Flexible Pipelines and Risers Integrity

Flexible pipes used in subsea production systems are predominantly metallic-armoured, unbonded multi-layer composite structures as illustrated in Figure 6-1 with design requirements governed by [24]. Competing flexible pipe technology includes bonded flexible pipes and emerging non-metallic flexible pipes. The physical characteristics and failure modes of these different pipe structures are diverse, therefore SIM practices will also differ widely.

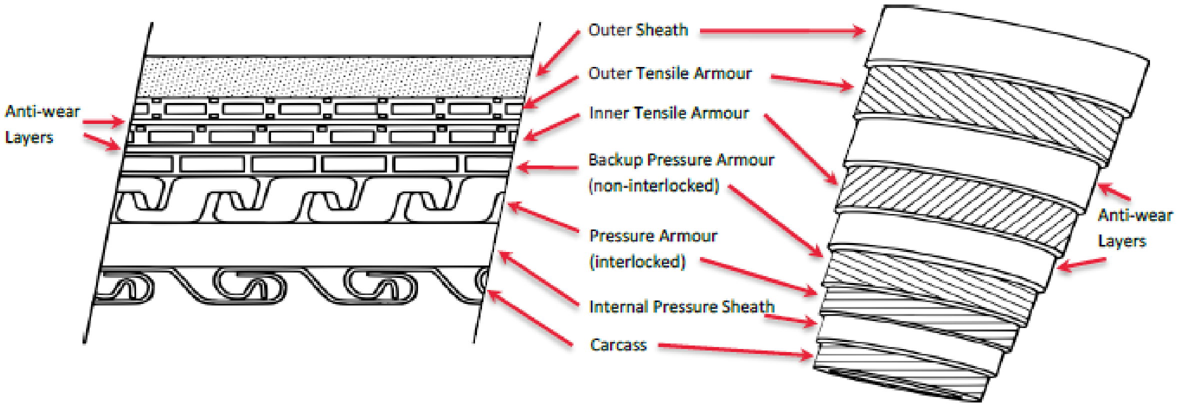

Figure 6-1 Unbonded Flexible Pipe Cross Section [26]

The key generic threats that are most commonly encountered for subsea flexible flowlines and risers are as listed below;

- Corrosion or fatigue corrosion mechanisms affecting the strength retaining metallic armour wires. The source of corrosion may be due to external seawater (in the event of a breached external sheath) or from gas constituents permeated into the annulus from the bore (e.g. CO_2, H_2S) or some combination of both. For dynamic risers, testing or monitoring of the dry (unflooded) annulus volume is routinely performed to establish annulus integrity and ultimately to the risk of pipe rupture.
- Ageing or degradation of the bore fluid retaining layer, the internal pressure sheath. This extruded thermoplastic layer has defined limitations in terms of temperature, depressurisation and chemical compatibility. Degradation mechanisms typically occur at localised areas, generally resulting in small leaks, as full pipe rupture is prevented where the tensile armouring remains intact.
- Threat of flow induced pulsations (FLIP) in dry gas systems. This internal flow resonance phenomena over the internal carcass profile has occurred on a number of field developments and can lead to operational restrictions on gas flow rates. The risk is associated with connected pipework fatigue and noise as opposed to a structural threat to the pipe itself. Several risers have to date been replaced due

to FLIP occurrence or concerns.

- Ancillary equipment damage, degradation and failure. Dynamic riser systems rely on a range of ancillary components to support the flexible pipe and control the riser configuration, therefore failure of such can result in subsequent failure of the pipe. There have been examples of in-service failure of a range of components, including bend stiffener connectors, bend stiffeners, buoyancy modules (slippage), MWA tethering systems and hold down arrangements. These components are typically inspected at the same time as the riser and at a frequency determined by the level of identified risk.
- Accidental events, e.g. mooring system failure or dropped objects / snagging events can lead to collapse, overbending or rupture of the flexible pipe. It should be noted that industry experience has confirmed that a flexible pipe cross section generally exhibits high resistance to accidentally imparted structural loading.
- Operational threats to the internal carcass layer due to fatigue, tearing or some multi-layer internal pressure sheath designs. The use of multi-layer pipes is becoming less common as the different manufacturers develop the capabilities of alternative sheath materials and pipe designs.

6.4 Rigid Pipelines and Risers Integrity

Rigid pipelines and risers properly designed, fabricated, installed, operated, maintained and inspected will give long term reliable operational performance. However, at no time can the attention of the Operator responsible for the ongoing integrity of these systems wander.

6.4.1 Design and Documentation for Rigid Pipelines and Risers Integrity

Consider a rigid pipeline that has been designed using stress-based limit parameters intended to be conservative and that was operated as intended yet unexpected in-place behaviour took place such as:

- Sections of pipeline are not completely stable on seabed when subject to wave/current loads (DNVGL Generalized Method allows up to 10xOD lateral movement) and move into a precarious position (e.g. In contact with a boulder)
- Cyclic in-place behaviour such as global buckle development and evolution, pipe walking and strain ratcheting / low-cycle fatigue due to thermal / pressure cycles causing pipeline expansion and contraction.
- Hydrogen embrittlement of pipe material due to appurtenances with different materials, presence of H_2S or CP system malfunction.
- Pulsations in pipeline due to excessive slugging (turn-down flowrate) provoking tie-in spool vibration modes and high stresses leading to premature fatigue at stress-concentration sections.
- Seasonal seabed scouring creating spans leading to premature fatigue failure, or at least reduced lifetime unless mitigated in time

A pipeline can be considered a quasi-static / dynamic system not fully covered by stress-based design factors because the above-mentioned threats alter the geometry of the pipeline over time, i.e. the pipe has moved away from its original position.

To capture all the integrity risks as part of a regular integrity program/plan requires the integrity engineers to be well aware of all the potential issues that may threaten the integrity of a pipeline, i.e. in addition to the traditional and well recognised risks such as anode depletion, initial free-spans mitigated at time of installation, external damage and internal corrosion.

Some examples of anomalies that might be missed in a "traditional" inspection plan are:

- Discovery of rogue/unplanned buckles: It might be difficult to discover such buckles unless particular attention is made to discover them. E.g. it is typical that one has to zoom in closely on survey data (xyz data) to discover these features with the naked eye.
- Increased load in planned/design buckles over time: A potential risk related to a planned buckle may be that the bending loads become more severe over time, e.g. because of increased thermal feed-in. In order to monitor this, it is necessary to monitor the development of the buckle curvature. The curvature can be estimated from the survey data using appropriate numerical tools. There is known experience, where a pipe initially buckled at the intended buckle sites, but eventually ruptured at one location with overload at other sites. In this case, the cause was deemed to be design errors relating to load prediction, but it was retrospectively concluded that the initiation of the excess defects could have been identified prior to failure.
- Build-up of soil at front of a buckle apex will lead to increase in lateral resistance with potential increase in maximum bending load and stress cycles.
- For some pipelines, the operational cyclic stresses in a thermal buckle may be important contributors in the fracture assessments (ECA). Thus increased stress cycles should be checked both against design fatigue assessments and ECA assessments where relevant.
- Axial ratcheting (walking) may be difficult to discover from survey as there will typically be no fixed reference points to measure accumulated axial expansion against and it will typically also be "masked" by the thermal expansion associated with different operating modes of the pipeline. Where severe ratcheting is identified as a potential issue, it would be good practice to establish a methodology to monitor / overlay the development of this over time.

It is further essential that the designer, as part of the handover to operation, documents all the potential issues and potential threats that may develop over time and describes in detail how this can be monitored together with detailed acceptance criteria.

6.4.2 Rigid Pipelines and Risers Integrity during Operation

Operators must continually challenge established norms and be active in updating integrity management strategies as new information becomes available whether this be acquired from the operation of the assets themselves through things like inspection or maintenance, or through external sources like updated codes and standards, joint industry initiatives, Operator forums, new technology, etc.

The principals of integrity management applies across oil and gas assets generally. Looking more closely at subsea rigid pipelines and risers, the following is a list of the most common threats encountered;

- Depletion of anodes leading to requirement to replace or commencement of external corrosion on pipelines and structures.
- Scour of the seabed around pipelines and structures leading to spanning or high displacement stresses. Coupled with increased embrittlement/cracking mechanisms such stresses can lead to failure.
- Impact/snagging damage from fishing activities or vessel anchoring can lead to coating damage and

hence increased demand on anodes or, on smaller bore equipment, LoC through over stress and failure. Large forces from anchor loads can displace pipelines and dent/gouge the pipe wall.

- Internal corrosion due to change in fluid constituents from original BOD or from damage to internal coating barrier.
- Overlooked at design stage small component failures.

Operational interfaces also often exist with other 3rd party pipelines or field operators who either directly tie in to pipeline facilities or whose subsea facilities are in close proximity.

Tie ins can come after the main pipeline has been in commission for some time and different codes and standards can be used in the design of tie-in pipelines compared with those of the existing pipeline. The operators and project teams must ensure close co-operation at the design phase to ensure consistency and compliance across connection points and, in particular, care should be taken to ensure the operation of the new tie-in pipeline does not jeopardise the safe operation of the existing pipeline. Specifying different (higher) entrant pipeline design pressures is not uncommon where pressure drop in the entrant pipeline is effectively added to the main pipeline design pressure to ensure fluid can enter the system at normal operating pressures. Once tied in, the new pipeline needs to be included in the whole pipeline 'system' and the operation of the new and old pipelines needs to be considered holistically. System hydraulic performance needs to be understood under all operating scenarios and the risk of overpressure on one part of the system from another needs to be managed by clear operating procedures, Safety Valves and HIPPS set point design and confirmation of code compliance.

For subsea facilities that are in close proximity to one another care must be exercised in any works undertaken by 3rd parties at these locations to ensure that one parties activities does not adversely impact the operation of another's. Procedures should be established that set out the operators' requirements to allow work in close proximity to their subsea assets in terms of timely notification and technical detail. Provision of this information at an early point will allow any risks to subsea equipment to be assessed and mitigative steps to be taken prior to the work taking place. Threats can be from impact from ROV's on subsea pipelines and structures, incorrect operation of subsea valves within tie-in structures, damage from installation of new pipeline/cable crossings etc.

Structures and pipeline should be designed to be able to withstand forces and impacts from fishing activity which is intensive in the North Sea. The evidence of fishing activity can be seen in ROV footage gathered from routine GVI surveys and is typically;

- Coating damage on structures
- Trapped and discarded nets
- Damaged or missing structural grating
- Debris dragged by nets and deposited alongside pipelines

It is rare that fishing activity causes loss of primary containment as loads and impact energies are typically low compared with the structure strength of subsea equipment and structures, but this can occur. Designers need to ensure suitable measures are taken to protect subsea equipment and operators need to ensure, through routine inspection, that these design barriers are maintained as effective for the life of the assets. For longer term operation designers and operators should also consider not just risks from current fishing practices and equipment but also those that may be employed in the future particularly in regard to the size and weight of the equipment and the additional damage potential this may entail

6.5 XMT/Wellheads Integrity

For successful well integrity management, the operator must consider the full life cycle risks and have approved procedures for all well workscopes. There should be a defined fit for purpose maintenance, inspection and testing programmes. A process has to be in place to ensure that all well personnel are aware of the implications of wellhead/XMT problems and any actions to be taken. This can be achieved by a clear description of roles and responsibilities.

Well barrier schematics must be defined for well activities and phases, e.g. drilling, well testing, well completion, production / injection, etc – identifying primary and secondary well barrier elements for activities through the life cycle of a well. NORSOK D-101 provides example for well barrier schematics and further definition of well barrier elements.

The key threats most commonly encountered for XMT/Wellhead and associated components are as listed below, and some examples for possible leak paths are illustrated in Figure 6-2 below;

- Internal corrosion - Loss of wall thickness leading to leaks/ pressure loss. This can be eliminated during the material selection phase by using the right grade of steel. Control procedures include;
    - Batch or continuous inhibitor treatment/injection
    - Chemical treatment of injection water (at surface)
    - Batch chemical scale removal treatment
    - Monitoring of the annulus
- External corrosion
    - Coating Damage / Excessive CP Wastage / External Corrosion
- Valve erosion - Wear due to well fluid flow, sand/debris/scale flow. Control/IM procedures include;
    - Sand isolation and management
    - Scale management
    - Routine valve testing and monitoring
- Loss of Comms - Electrical failures leading to inability to remotely operate the ESD valves, failure in umbilical power/comms due to accidental damage, fatigue, service loads etc. Control/IM procedures include;
    - Monitoring of voltages/current (high and low alarms)
    - General Visual Inspection (GVI) post extreme event etc
- Valves failure to operate (Open or close) - This could be as a result of fouling, hydrate in control line, particulates or solids blockage, manual override, erosion of valve trim, loss of comms, loss of hydraulics, actuator failure etc. Mitigations include;
    - Functional testing at a regular frequency
    - Leak testing at a regular frequency including where possible valve signature trending, hydraulic consumption analysis etc
    - Visual inspection

  - Monitoring of solids/ sand production

- Structural damage to XMT/Wellhead structure - Physical damage from collision (ships, trawlers etc). Mitigations include;
  - Adequate protection/barrier around the subsea structure
- Sensor failure - Inability to monitor well parameter for e.g. Pressure and Temperature via the pressure transmitter/indicators. Mitigations include;
  - Maintenance and recalibration of sensors
- Failure of the valves to hold pressure - Physical damage, seal failure, blockage by particulates/solids, scale etc. Mitigations include;
  - Routine maintenance and testing

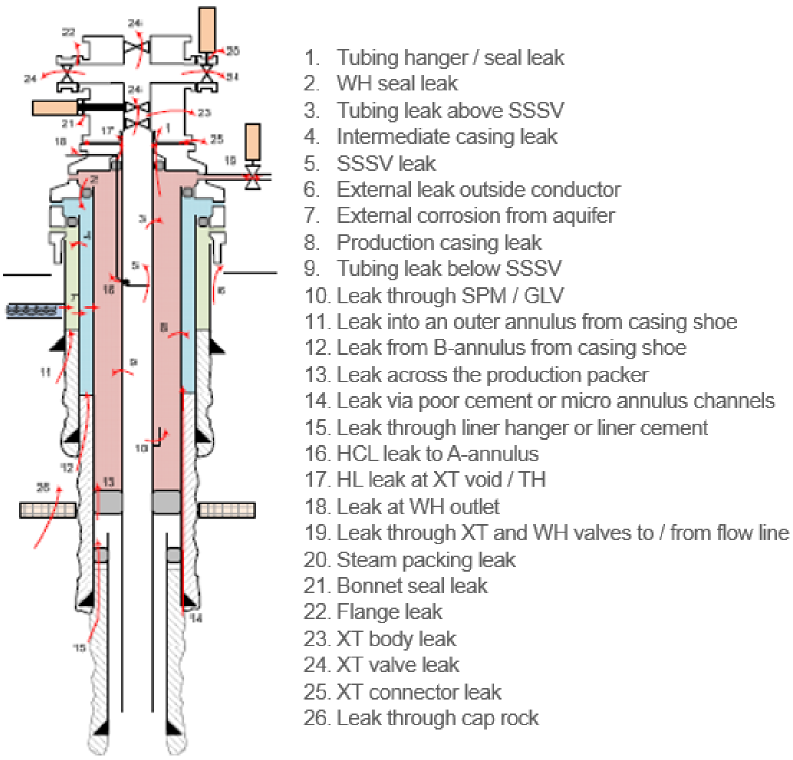

Figure 6-2 Possible Well Leak Paths

Well integrity can be defined as the condition of a well in operation that has full functionality and two qualified well barriers envelopes. Common integrity issues are often related to leaks in tubulars or valves. A pilot study by PSA in 2006 covered inputs from seven operating companies, 12 offshore facilities and 406 wells indicates that 18% of the wells in the survey had integrity failures, issues or uncertainties and 7% of these were shut in because of well integrity issues. A later study indicated that each fifth production well and each third injection well may suffer from well integrity issues [32].

6.6 Subsea Valves Integrity

6.6.1 Valve Types

Although it is not within the scope of this guideline to address safety integrity level (SIL) rated safety instrumented systems (SIS) or safety instrumented functions (SIF) in any detail, it is noted that safety valves perform specific barrier functions as part of independent barrier and pressure protection systems (PPS). Valves forming part of such barrier functions are designed to be fail safe and will automatically (mechanically) go to safe position, often closed, upon loss of an active signal from e.g. the emergency shutdown (ESD) system. The configuration of valve barrier systems may vary between assets and installations;

- SSIV - The subsea isolation valve (SSIV) protects the platform and its personnel from unintended release of hydrocarbons by containing pressure in accordance with DNV Zone 2 [23] requirements and minimising the volume in the riser section of the system by isolating the majority of the pipeline volume from the riser. The reduction of the hydrocarbon volume reduces the consequences in case there is a leak in the riser or topside.
- ESDV – The emergency shut down valve (ESDV) is an actuated valve designed to stop the flow of hydrocarbons upon detection of a hazardous event.
- HIPPS – High Integrity Pipeline Protection Systems (HIPPS) being less common, are implemented in cases where an additional layer of protection is required based on identified and plausible overpressure scenarios for a given hydrocarbon containment system. Typical HIPPS contain two high integrity Barrier Valves (BV), autonomously controlled by the SCM SCCBs and with no possibility for HMI from the MCS to interfere with the autonomous operation resulting from a HIPPS trip signalled by the PTs ultimately closing the BVs.

A generic example showing a possible layout and placement of safety valves is given in Figure 6-3 below.

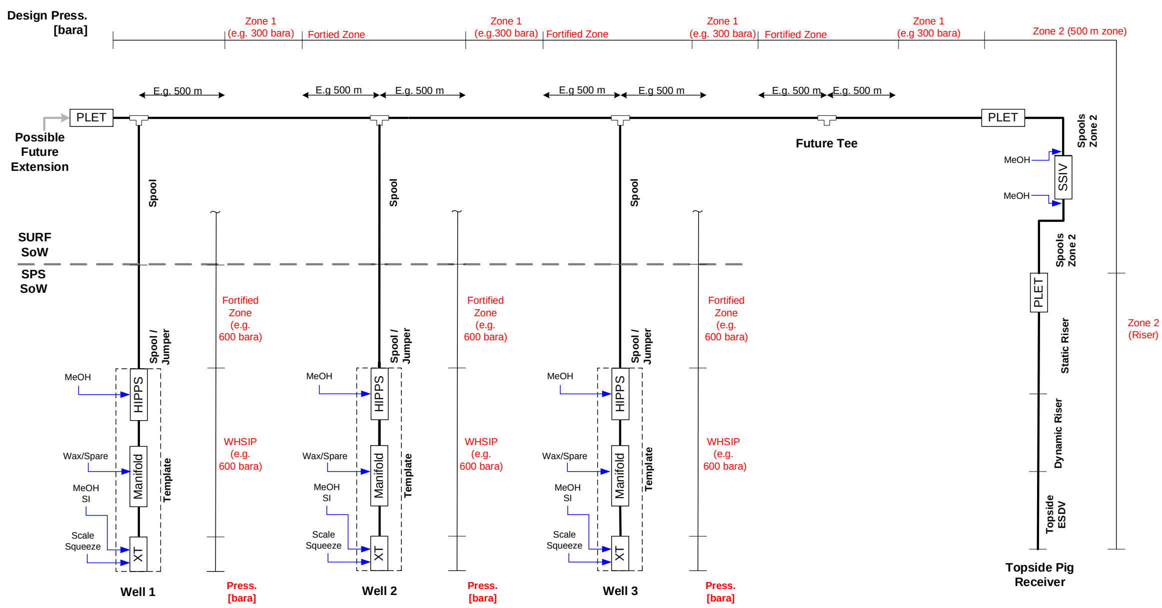

Figure 6-3 Generic Example for Subsea Barrier Valve Schematic

Reference is made to DNV-ST-F101 [23] for Zone 1, Zone 2 and Fortified Zone design pressure requirements, but the main functions are;

- Normal Pipeline (Zone 1) – contain pressure in accordance with DNV Zone 1 requirements. A secondary function is to act as a weak link (lower expected burst pressure than Zone 2 pipeline and riser).
- Zone 2 (Riser and 500 meter platform safety zone) – contain pressure in accordance with DNV Zone 2 requirements, i.e. be a "stronger" link than the zone 1 pipeline.
- Fortified zones of the main pipeline – contain potential dynamic pressure surge/build-up which may occur before the pressure protection system has closed off the flow upon detection of high pressure. This may be caused by e.g. a blockage downstream or by a pressure/flow controlling device (choke) failure upstream.

As discussed in section 5.0, there are variations in pressure definitions across standards applied for components forming part of the subsea system. It is important that pressure rating of all components is well understood and documented as part of the pressure protection philosophy, requirements definition and design. A conservative approach should be taken to maintain safety margins across component interfaces, including potential for chemical injection system to over-pressurise any component in the system. The pressure rating interface between SURF and topside must be well understood and documented to ensure topside equipment and components do not become a weak link in the system.

Valves not forming part of the pressure protection system include;

- Manual isolation valves - stops hydrocarbon flow and can be set to open or closed position by the operator in order to isolate parts of the system for various production and maintenance scenarios and may be actuated or require manual operation (mainly by ROV on the NCS, diver operation is more common in some other regions).
- Control valves, e.g. choke valves – are actuated valves used to control pressure and flow in the hydrocarbon transportation system.

XMT and well safety valves are covered under XMT and Wellhead integrity, Section 6.5.

This guideline does not aim to give a full introduction of all subsea equipment and types, and reference is made to e.g. the OREDA handbooks [8] for further identification of valve types and associated failure modes.

6.6.2 Valves Integrity

Valves can be broken down in the following subunits and maintainable items [8];

- Bonnet
- Closure member
- Flange joints
- Packing / Stem seal
- Seals
- Seat rings
- Stem

- Valve body w/ internals

To ensure valve functionality and integrity is maintained, the life cycle of a valve from design, specification, selection and procurement through storage, installation and operation needs to be considered.

6.6.2.1 Valve Selection

Service conditions needs to be considered and specified prior to selection of a pipeline isolation valve, for example;

- Line purging, dry cycling or the presence of an abrasive like sand may cause throttling damage on the soft seats of a ball valve, whereas a metal seated valve is designed to resist seat wear in these conditions, e.g. seen for mainline isolation valves.
- Failure to select a valve according to required specifications or to cycle, operate and test the valve according to valve supplier specifications may cause the valve to leak internally (fail to isolate) or cause seep leak across valve stem seals. The operator's ability to maintain production or to isolate a pipe section could depend on the ability of a single isolation valve to hold pressure.

6.6.2.2 Valve storage and handing

Valve care before initial installation is key to maintain valve integrity;

- Large diameter valves should not be stored on dusty construction sites with no end covers or alternative protection from airborne contaminants. It is a risk that internal sealing integrity of the valve may not be taken into consideration by a construction crew concerned with timely installation.
- Improper transportation of the valve itself should be of paramount concern to project managers. Any rough handing of the valve could cause damage to the ball or gate, with the potential to expose the valve seating area to contamination. Any opportunity to prevent contamination of the valve assembly will increase the likelihood of achieving a positive seat test once installed.

6.6.2.3 Valve Inspection and commissioning

Of any step taken toward ensuring a subsea valve operates efficiently and safely, valve commissioning is the most crucial.

- Failure to lubricate the seat sealant system or seat ring groove during commissioning has been experienced to cause complete washout of seat seals during nitrogen purging. One specific case, resulting in resurrection of three brand new 36 inch buried mainline block valves, may serve as an example; During valve installation, construction debris was trapped inside the pipe where the butt ends were welded. Once installed, the purging process pushed the construction debris against the valve ball and into the gap between the seat ring and the sealing face. If any lubricant had been injected into the valve seat sealant system during commissioning, enough of the debris would have been pushed out and away from the sealing area to ensure minimal damage would have occurred. Instead, the valves were dry cycled and so severely damaged that they required replacement before the pipeline section could be brought online.

The example above shows the importance of implementation of a strict valve commissioning and pipe inspection procedure. Any welding slag, dirt, rocks, and any other kind of debris must be meticulously removed from pipe sections before valve installation. Every valve needs to be purged of factory grease and replaced with a high quality synthetic lubricant and air tested to ensure that the seat seals maintain their integrity.

6.6.2.4 *Valve operation, cycling and testing*

Valves in a subsea environment are maintenance free, with one key exception - the only way to maintain a subsea valve is to operate and cycle it. Unfortunately, experience shows operators tend to operate valves only by necessity, i.e. when an isolation is required or in the case of safety critical valves such as SSIV's or ESDV's where operation is mandatory. A subsea valve integrity management program should address and implement vendor recommendations for valves operation, cycling and testing.

To properly maintain subsea valve functionality and integrity, a scheduled routine of movement should be implemented. Unfortunately, the location of subsea valves makes it difficult, impractical and costly to operate them. For Safety critical valves such as SSIV's or ESDV's, routine operation is mandatory, i.e.;

- Quarterly partial closure test, where the valve closes 10% before reopening. Confirming operation with no interruption to the production.
- Annual full closure test, confirming safety critical valves are fully operational.

6.6.2.5 *Valve Operation and ROV interface*

As operation of ROV operated subsea isolation valves is costly, they are procured to be maintenance free for their design life usually around 20 to 25 years. Today many installations have exceeded their original design life, and in many cases operators are required to operate valves that are way beyond their original design life. A procedure for operation of ageing valves must give details of the ROV drive, e.g. ISO 13628-8 class 4, including the maximum allowable operating torque and the number of turns to Open/Close. Any attempt to operate a valve that has not been operated for many years should be done with great care and any torque applied to the ROV override should start low being gradually increased, continually cycling the valve Open/Close to gradually increase the range of movement.

As part of FAT/EFAT of the subsea structures, verification of all ROV intervention activities, including ROV accessibility by means of an ROV simulator should be performed. Valves within subsea structures should be clearly marked with high visibility AQUASIGN labels and operators should maintain a Valve Matrix for each structure updated after each intervention, with the "As-Left" status of the valves. ROV should be equipped with high pressure water jetting to enable the cleaning of the valve identification labels and position indicators. Some operators have standardised on the ROV interfaces across it's assets, however not all projects have applied the same control in adherence to these standards. Also, some fields with an operators portfolio have been attained through acquisition and not all were built to the same requirement. Hence each time an intervention is planned either by DSV or ROVSV care should be taken to ensure the valve data is current and up to date.

Operator mistakes may cause maloperation of actuated valves with a potential for LoC. Maloperation of valves have caused LoC and hydrocarbon leak on the NCS, including incidents in 2003 and 2013 listed in section 3.1.2.

HIPPS internal leaks are known to have occurred across the high integrity barrier valves (BV) gate. The immediate mitigation is having two BVs and additionally a test valve of the same integrity as the BVs, although not HIPPS controlled. In case full functionality of the HIPPS system cannot be restored, other measures such as repair or operational changes, e.g. pressure de-rating may be required.

7.0 In-Service Integrity Measures

This section of the guidance presents potential measures which may be applied to the various system sub-elements to mitigate specific threats / risks. These measures reflect the integrity management measures that are commonly utilised at this time. This should not be seen as a barrier to new measures i.e. new inspection / monitoring systems which are still under development. These are categorised under one of the following sub-categories;

- Inspection, Monitoring, Testing and Analysis, and Preventive Maintenance and Remediation

Table 7-1 lists these measures applicable for subsea system. The applicability of the IM measure should be based on the failure mode assessment performed.

Table 7-1 Summary of In-Service IM measures

IM Measure		Rigid Pipeline	Rigid Jumpers & Spools	Flexible Pipeline Jumpers	Flexible Riser	Rigid Riser	X-Mas Trees (Pressure Containment)	Wellhead
Inspection	Close and General Visual Inspection	•	•	•	•	•	•	•
	CP Measurement	•	•	•	•	•	•	•
	Intelligent Pigging	•				•		
	Leak Detection	•	•	•	•	•	•	•
	NDE	•	•			•		
	Side Scan Sonar	•	•	•				
	Swath/Bathymetry/Multi-Beam Echosounders	•	•	•				

IM Measure		**Rigid Pipeline**	**Rigid Jumpers & Spools**	**Flexible Pipeline Jumpers**	**Flexible Riser**	**Rigid Riser**	**X-Mas Trees (Pressure Containment)**	**Wellhead**
Monitoring	Weight Loss Coupon	•	•			•		
	Polymer Coupon Monitoring			•	•			
	Environmental monitoring	•	•	•	•	•	•	•
	Erosion Monitoring	•	•	•	•	•	•	•
	Leak Monitoring	•	•	•	•	•	•	•
	Pressure Monitoring	•	•	•	•	•	•	•
	Mooring Tension				•	•		
	Load Cycles				•	•		
	Vortex Induced Vibrations (VIV)					•		
	Sand Production Monitoring		•		•		•	•
	Stress/strain monitoring				•	•		•
	Temperature Monitoring	•	•	•	•	•	•	•
	Tension				•	•		

IM Measure		Rigid Pipeline	Rigid Jumpers & Spools	Flexible Pipeline Jumpers	Flexible Riser	Rigid Riser	X-Mas Trees (Pressure Containment)	Wellhead
	Valve Functionality Monitoring				•	•	•	•
	Vessel Motion and Excursion Monitoring				•			
	Vibration	•	•		•	•		•
	Volume Flow Rate Monitoring	•	•		•	•	•	•
Testing& Analysis	Annulus Fluid Analysis				•		•	•
	Bore Fluid Sampling and Analysis	•	•	•	•	•	•	•
	Chemical Injection Log and Material Compatibility Analysis	•	•	•	•	•	•	•
	Engineering-Integrity Assessment	•	•	•	•	•	•	•
	Pipeline Span Analysis	•						
	Metal Loss Defect Assessment	•	•			•		
	Metallic Coupon Sampling and Analysis	•	•			•		•
	Microbial Analysis	•	•	•	•	•	•	•
	Structural Integrity Analysis	•	•	•	•	•	•	•

IM Measure		Rigid Pipeline	Rigid Jumpers & Spools	Flexible Pipeline Jumpers	Flexible Riser	Rigid Riser	X-Mas Trees (Pressure Containment)	Wellhead
	Vacuum Testing				•			
	Valve Response Analysis				•	•	•	•
	Water Injection Fluids Sampling and Analysis	•	•	•	•	•	•	•
Preventive Maintenance and Remediation	Anode Replacement	•	•	•	•	•	•	
	Chemical Inhibition Injection	•	•	•	•	•	•	•
	Cleaning Pig	•	•	•	•	•		
	Fabric Maintenance					•		
	Installation of Vibration Dampers/Supports		•		•	•		
	Marine Growth cleaning				•	•	•	•
	Periodic Valve Cycling				•	•	•	•
	Sensor Calibration	•	•	•	•	•	•	•

8.0 Integrity Management System

8.1 Integrity Management Framework Development

The development and implementation of the integrity management framework involves many managerial and technical functions and impacts in the various levels within the organisation. It is therefore important that activities are carried out within a structured framework that is visible, understood by all parties and where roles and responsibilities are clearly defined.

Asset management is based on a set of fundamentals [33]:

- Value: Assets exist to provide value to the organisation and its stakeholders
- Alignment: Asset management translates the organisational objectives into technical and financial decisions, plans and activities
- Leadership: Leadership and workplace culture are key for realisation of value
- Assurance: Asset management gives assurance that assets will fulfil their required purpose

As illustrated in Figure 8-1, the asset management system and IMS should support the successful achievement of organisational plans and objective.

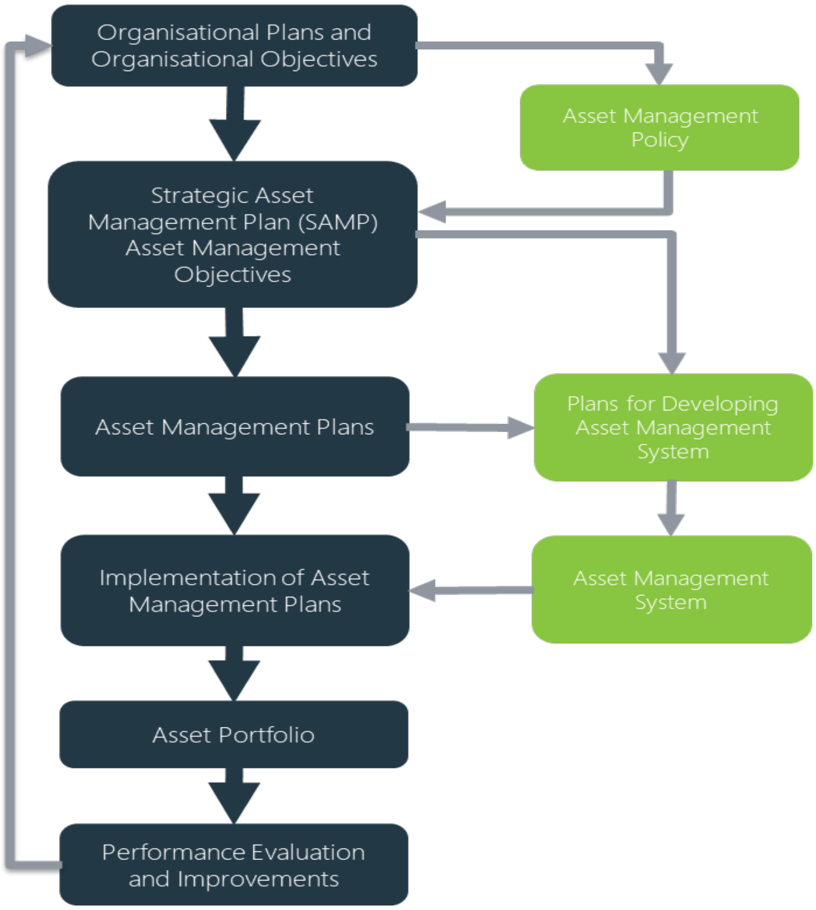

Figure 8-1 Relationship between key elements of an asset management system [33]

The following steps should be followed in order to ensure a successful IMS framework development:

Organisational Structure and Objectives – Definition of roles and responsibilities of management and staff within the organisation.

Planning, Procedure and Implementation – Development of plans and procedures in such a way that activities are carried out in a logical order and in an efficient way that is fully auditable. This includes data collection and engineering analysis to ensure any developing deterioration is identified and mitigated, through risk assessments, monitoring, inspection procedures, data collection/ analysis and remediation.

Measure System Performance – Methods to measure performance of the system against pre-determined criteria; key performance indicators will be identified to monitor and measure the extent to which policy objectives are being met by the integrity management system.

Review System Performance – Systematic and regular review of system performance by reviewing activities and trends, checking for compliance and learning from experiences and making updates and improvements. This will also include performance against industry standards and best practices in the industry.

Audit – Use of periodic audits to ensure the system is efficient, effective and reliable and that processes are being implemented in accordance with procedures and regulations.

This approach sets up the operation of the integrity management system while it also ensures that lessons learned are fed back for future improvement.

8.2 Stages of Integrity Management Framework Development

It is recognised that there are many ways to organise and operate successful integrity management systems, each of which is asset specific depending on factors such as: design criteria and safety factors in design, stage in life cycle, process conditions and operational history. The integrity management framework implementation should be split up into four main stages as follows:

8.2.1 Stage 1 - Gap Analysis, Review and Definition of Scope

A core integrity management team composed of integrity engineers, subject matter experts and end-users should be established to address the integrity management program. The IM team will review the operator policies, current asset integrity management system and operating procedures such as they exist, depending on the project life cycle, and organisational structure. The team will review and understand ongoing practices. The key elements of the IM Program should be revised and assessed based on these reviews and practices. The IM team will review existing and developing Standards and Regulations on the subject of IM to ensure those requirements and recommendations are constantly met. A baseline gap analysis will be performed to allow benchmarking of the key elements of the Program with operator practices. Lessons learned will be incorporated into the baseline strategy.

8.2.2 Stage 2 - Program Development

The program development stage is where key elements and deliverables are developed and/or improved as part of the IM Program. Specific procedures and plans to address any shortfalls will be established, and the programs will then be executed to ensure that the "Gap" between "current" and "target" levels are successively reduced. Short-term and long-term goals will be set to gauge the future performance of the IM Program. In addition, continuous improvement methodologies will be put in place to ensure continuous improvement in performance of the IM Program.

8.2.3 Stage 3 - Implementation

Based on the key elements identified as part of the IM Program Development, the implementation stage is where the IM team will execute the identified procedures and plans. The implementation plan will describe steps required to meet the key objectives, resource requirements and a schedule for implementation. It is recommended that the initial implementation is performed for a selected pilot to ensure lessons learned are captured and implemented for subsequent assets to be included in the IM Program.

8.2.4 Stage 4 - Continuous Improvement

This is an ongoing and "live" phase where the IM Team will continuously review the IM Program and make improvements as it develops. While the best plans and programs can be developed, it may not necessarily be the best solution for a given, specific asset or operation. Optimisation of activities can be carried out to enable the IM Program to run more effectively and efficiently (e.g. ALARP).

The asset integrity process during operation, including continuous update and improvement of the asset management (AM) plan is summarised in Figure 8-2 below.

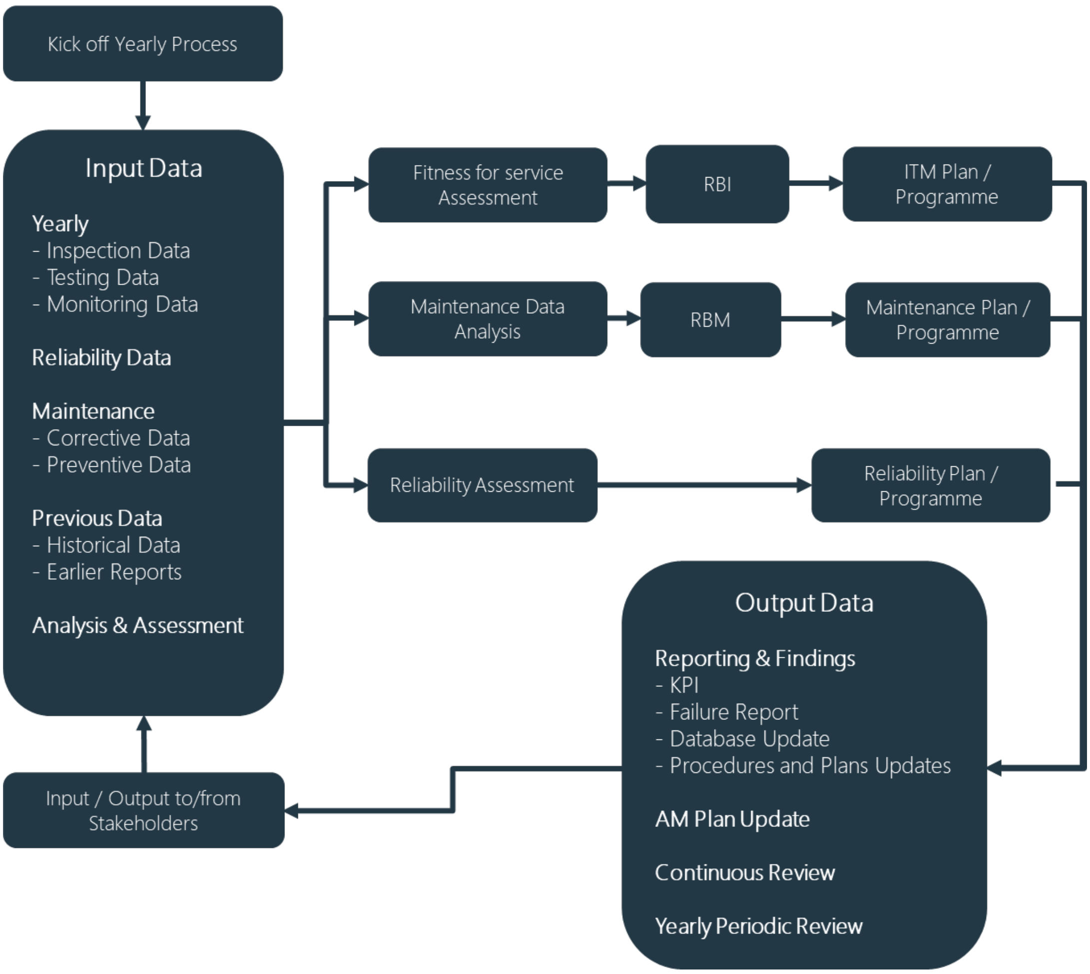

Figure 8-2 Asset Integrity / Maintenance Management Process during Operational Phase

9.0 Lifetime Extension

9.1 Lifetime Extension Method

In Norway, the LTE methodology is widely described in;

- NORSOK U-009, Life Extension for Subsea Systems,
- NORSOK Y-002, Life Extension for Transportation Systems,
- Norwegian Oil and Gas RL 122, Recommended Guidelines for the Management of Life Extension [34].

Several recommended practices have been developed outside Norway regarding life extension, with a similar approach as the Norsok requirements and recommendations;

- ISO 12747, Pipeline Transportation Systems - Recommended practice for pipeline life extension,
- UK Health and Safety Executive, Key Programme 4 on "Ageing and life extension programme",
- Oil & Gas UK, Guideline on Ageing and Life Extension of Subsea Pipelines and Risers,

The diagram below recaps the overall process. Data collection is key to a successful lifetime extension assessment.

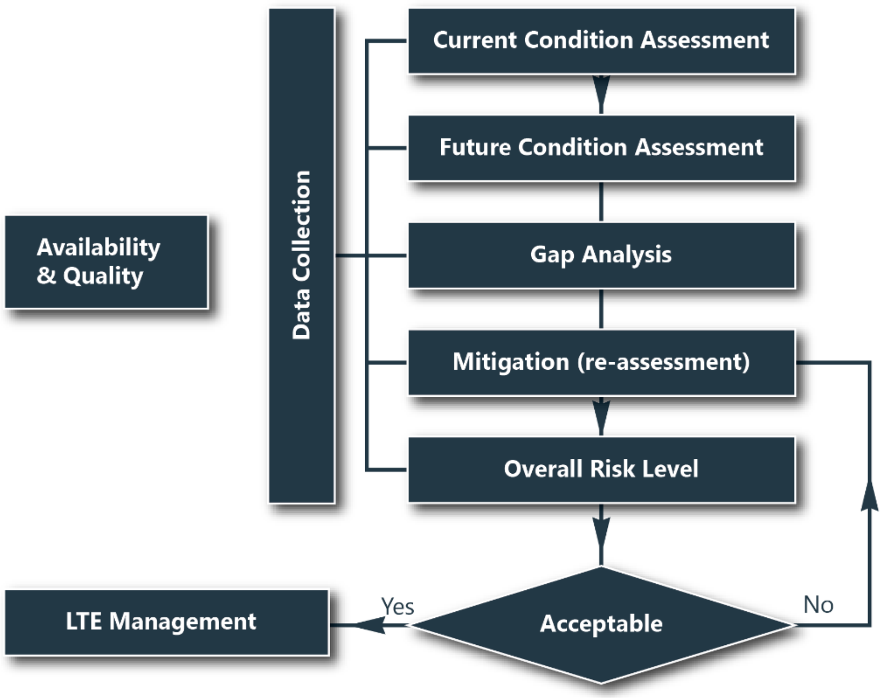

Figure 9-1 Lifetime Extension Typical Process

9.2 Data Availability and Quality

Data availability and quality is critical and essential to make reliable, robust and informed decisions regarding the condition assessment of an asset. By availability of data, it is meant that the data should be complete and accessible, while by quality of data it is meant that the data should be accurate, consistent and precise.

Data, regardless of whether it originates from design, construction, operation or integrity assessments, needs to be collected with the mindset, and in an appropriate format, to be used for day to day integrity management of the asset, but also for potential lifetime extension studies. A data management plan should be in place from the start-up of an asset, to ensure correct data collection throughout the operating life, following the framework and stages as outlined above and in sections 4.2 and 8.1. The operator should have dedicated resources and systems to collect and store data through the asset life cycle and to be available for review and updates at the time of an LTE assessment.

In cases of inadequate data management, there is a risk for lack of availability or quality of data which will impact the execution and outcome of an LTE assessment. Typical data availability issues are that data are lost and/or not acquired during the operating life. Typical data quality issues are inconsistencies in data (i.e. from different sources), unrepresentative data (i.e. referring to wrong tag numbers or not well defined naming conventions) or incomplete data (i.e. missing key design parameters, or due to sensors and monitoring equipment not functioning).

For LTE assessments of ageing assets, data from similar assets can also be useful, either from Operators/Partners similar assets or lessons learned from Operators sharing forums. Other ageing data and generic failure data can be obtained from existing failure mode statistic databases (e.g. PSA CoDam, PARLOC, OREDA, Sureflex JIP), but should only be applied with great care for specific assets and cases. It is very important to clearly capture any assumptions made, including reference to applied data sources and any filters applied for extraction and potential adaptation of data (e.g. based on expert judgement).

In case the LTE assessment necessitates any amendment of design parameters forming part of specifications and setpoints definition for safety instrumented systems (SIS), as briefly discussed in section 6.6.1, the Operator must ensure appropriate action is taken to maintain barrier function.

9.3 Key Threats for Lifetime Extension

In the context of lifetime extension, one may differentiate threats which are time related to those which are not. Time related threats such as corrosion or fatigue will need to be considered for lifetime extension. For instance, corrosion and fatigue may not be acceptable for the required lifetime extension. Non-time related threats that occurred in the past life might have an impact on future condition of the Asset especially if the threats lead to wall thickness reduction; it will impact fatigue or corrosion risk for instance. Non time-related threats such as impact or external damage are managed via the integrity management framework during the lifetime extension and may be considered less relevant for the process, although in-place mitigations / assumptions should be re-validated. The lists of threats to consider for each system are well detailed in DNVGL-RP-F116 and DNVGL-RP-0002.

Another aspect of LTE assessment is that some component or part might become obsolete with the required lifetime extension; the component might not be for sales anymore or the acquired spare part might require some maintenance or inspection. Whenever a potential threat is high and lead to repair or maintenance of the spare part, it is necessary that it is addressed into the LTE assessment.

The handover documentation from the pipeline design and engineering phases of the pipeline system to installation and operation phases (identified as DFI and DFO in DNVGL F-116) should contain details that may develop over time and require extra-ordinary monitoring.

> *An example is the awareness of the increased corrosivity of the transported fluid if operating parameters are out of bounds, even temporarily. A water/oil separator was removed for repair without immediate replacement and without performing cleaning pigging to remove accumulated water in the pipeline after repair completed. The operating personnel may have misunderstood that the water was being removed to meet sales specification*

and could be removed further downstream in the transportation system. The hefty corrosion allowance determined for material selection early in the design phase was included to mitigate the risk of CO_2 corrosion in produced water at bottom of pipe in the case of stratified flow conditions over longer periods. After a while, the pipeline was routinely ILI'd and the operator was surprised to discover pitting corrosion up to 73% of the wall thickness, forcing an expensive repair.

Upset incidents and experience summary (lessons learnt) of the previous operator should be included in handover documentation as an entry in a risk / anomaly register or similar, and made available to the engineers evaluating LTE, as a "heads up". Unfortunately, some operators may not make upset incidents known outside their organisation, keeping the lessons learnt (solutions to experienced issues and upsets) confidential because they are commercially advantageous. In a similar situation, where one operator team takes over responsibility from another due to changes in ownership, the "soft" information from lessons learnt would need to be translated into updated parameters or procedures and guidelines for the benefit of the new team and the LTE engineer. While such incidents may be reported in the control room logbook, their interpretation could be lost in translation unless there is a systematic method to capture and report them specifically.

The sales gas operating parameters may be based on planned production quotas but the gas velocity over the rough carcass of the flexible riser causes standing-wave pressure pulsations at the natural vibration frequency of manifold piping, known as FLIP (usually in topside/subsea small-bore piping which is typically not analysed in such detail during design, potentially leading to premature fatigue failure.

Material incompatibility leading to HISC may be experienced not only across direct spec breaks, but also where seawater creates a galvanic connection, such as exposed duplex steel in seawater in close proximity to Aluminium anodes of the CP system. The oxidation of the sacrificial anodes is balanced by reduction of water into 2H+ and O- ions on the steel surface. The concentration of hydrogen ions combine into H_2 gas that diffuses into the metal, ending up in internal cracks and high stress areas, leading to embrittlement and HISC. The NPD understood the urgency of this issue for austenitic/ferritic steels like 22%Cr Duplex and 25%Cr Super-Duplex and quickly developed special design guidelines for the industry which was later adopted as an RP by DNVGL. While the prescriptive RP only covers designs with Duplex or Super Duplex steel, the phenomenon can also occur in other alloys used in subsea pipelines and piping that are normally considered to be ductile such as Inconel, not to mention the more brittle high-strength steels and 13%Cr alloy, which is not mentioned in the RP.

Despite the good intentions of providing lessons learnt by one operator to another, a misunderstanding of the correct operating parameters can lead to repetition of the same fault. The solution has typically been to communicate such issues for discussion at a suitable forum as is carried out by committees of operators' subject matter experts (SME's). Eventually (years later), a clause or section in an RP or similar document may be added to provide guidance for such issues.

10.0 Gaps and Opportunities Identification

10.1 Gaps and Challenges

Subsea asset installation can be traced back to the '60s. Regulations, design asset integrity requirements, advancement in technology, and industry practice have evolved and matured the understanding of asset integrity management. Nevertheless, some gaps and challenges still exist in the implementation of subsea asset integrity management systems. Key current and future IM challenges identified by Wood's SME are captured in Table 10-1.

Table 10-1 Gap and Challenges

Life Cycle Phase	Element	Potential Gap
All	Cost savings impact on (reduced) requirements for multi-discipline and multi-team design and risk reviews	The cyclical nature of oil and gas commodity pricing has seen a raft of industry efforts focussed on managing and de-escalating costs. It is Wood's view that such measures can be counter to robust SIM if not carefully assessed on a cost-risk benefit assessment, and this view is often reflected through regulatory bodies. One particular example is an observed trend towards reduced requirements for multi-discipline risk workshops and design reviews. Cross-discipline design and risk workshops with participation across disciplines and organisations, allowing for communication across technical, organisational and operational interfaces, are still key as a means for optimising an overall system SIM. Establishing relationships across disciplines also promotes transfer of knowledge and experience – which also reinforces the importance of competency assurance through the life cycle of a project. Capturing risk at an early stage ensures efficient project execution. The risk is that focus on short term cost savings and reduced project allowance for risk workshops and design reviews will reduce meeting arenas where knowledge transfer between organisations and generations of engineers can occur.
All	Knowledge Sharing	Detailed knowledge and lessons learned sharing across subsea system fabricator, installations, operators, regulators may be limited due to, commercial impact, contract requirements, intellectual properties and patents, company reputation, and commercial competitiveness.
All	Shared IM responsibilities	Communication of inspection data between Duty Holder/Operator/Owner where IM responsibilities are shared through overlapping regulations.
Design	Regional difference on regulation requirement	Variability of design, operational, life extension, and decommissioning requirement between different regions. Subsea assets i.e. pipelines can be between different regional jurisdictions with different IM requirements. Different regional requirements to report Major Hazard Incidents.

Life Cycle Phase	Element	Potential Gap
Design	Design vs Operation	Operational IM should be considered at the design stage by projects to ensure required IM activities can actually be undertaken after commissioning.
Execution	Pre-commissioning threat assessment	Temporary but unique threats may be evident in the period between the completion of fabrication and commissioning. These can be significant if this period is unexpectedly extended.
Operation	Information technology and data system	Availability of design for older assets may not be available for lifetime extension assessments. Scattered data information i.e. no centralized documentation system
Operation	Technology	Gap in existing technology capability versus needs i.e. NDE technology capabilities and limitations. Specifically, for dynamic flexible risers, inspection technologies capable of reliably detecting degradation in all load bearing layers remains as a gap.
Operation	Reliability of inspection footage	Potential for equipment degradation to be obscured by marine growth coverage, particularly late life subsea equipment. Selection of appropriate marine growth cleaning frequency / method.
Operation	Resource requirements	Thorough IM is a detailed and exhaustive process and an Operator must be aware of this and make arrangements for suitable resources to support the IM process.
Operation	Lack of operation and periodic cycling of subsea valves.	Generally, subsea valves have robust design and manufacture quality and perform as a strong link in the pressure containment system. A main threat for subsea valves is the lack of implementation of the manufacturer's operation and maintenance recommendation for valves cycling, both for commissioning and during the operational phase. The end defect will typically be fail to open/close on demand with potential for internal leak and a loss of the valves function to isolate. There is generally a lack of consistency in the quality of records and implementation of operational procedures for valves testing across different operators and assets, both for SSIVs and topside riser ESDVs.
Operation	Valve stem and test ports.	Subsea valve interfaces to connected subsea assets i.e. flanged connections are generally robust with few experienced know failures on valve connections. Minor leaks are however known to occur on the valve stem and/or valve test ports.
Operation	Design life extension	Valves may be a potential weak point for lifetime extension of subsea assets due to lack of implementation and recording of cycling and operation history.
Operation	Chemical compatibility	There are records of welds for weldnecks and small bore piping fitted on valves being exposed to non-compatible chemical compounds that resulted in excessive internal corrosion and loss of wall thickness, with a potential for HC LoC.

10.2 Opportunities

Technology advancements is identified as the main opportunity to improved management of subsea systems integrity, with a potential to achieve higher safety and integrity levels with the same or fewer resources needed. Especially for subsea systems, there is however still a gap between the potential promised by new technologies, practical implementations and results achieved. As such, strong support from regulators and key stakeholders in the industry is needed to make sure products resulting from technology research and development are suited for subsea integrity management requirements.

The sections below list some of the available and emerging technologies for subsea asset integrity management. It is noted that this report forms part of an initiative by the PSA to investigate subsea asset integrity management and the potential of emerging technologies to be implemented for this purpose. Emerging technologies are treated in further detail in other reports forming part of the PSA initiative.

10.2.1 Advanced Subsea Visual Inspection Technology

Traditional subsea structure General Visual Inspection (GVI) using ROVs typically involves a certified subsea inspector located offshore, watching a live video feed from the ROV, interpreting and eventing the video in real-time and performing CVI by ROV standoff and zoom-in, if necessary. These exercises usually require significant time to complete.

UHD imaging technology has enabled high quality images to be captured offshore. With a robust inspection procedure that gives clear guidance to the ROV pilot and correct equipment set-up, high-quality inspection data can be post processed and analysed onshore. This enables offshore campaign resources to be focused on the data acquisition activity using a ROV mounted UHD camera. An example case of this type of operation reduced the inspection time by 80%. Consequently, there is further reduction in vessel cost, carbon footprint, risk associated with offshore operation and required personnel offshore.

10.2.2 Subsea Asset Reconstruction using Machine Learning

Machine learning has enabled the reconstruction of subsea substructure with 3D geographical position using multiple historical ROV survey videos and corresponding survey positioning data. This process enables the quantification of structure displacement between consecutive assessments that can also be used as critical input for a pipeline FFS assessment.

10.2.3 Digital Twins

Digital twin is a virtual replica of the physical subsea asset. It integrates artificial intelligence, machine learning, and data analytics to create a live digital simulation model that will update and change as the physical asset changes. It can serve as a 'single source of truth', minimizing the risk of outdated and unaligned asset information being applied for decision making and thus maximizing the value of asset information acquired from different data sources including integrity management related data monitoring i.e. Integrity operating window.

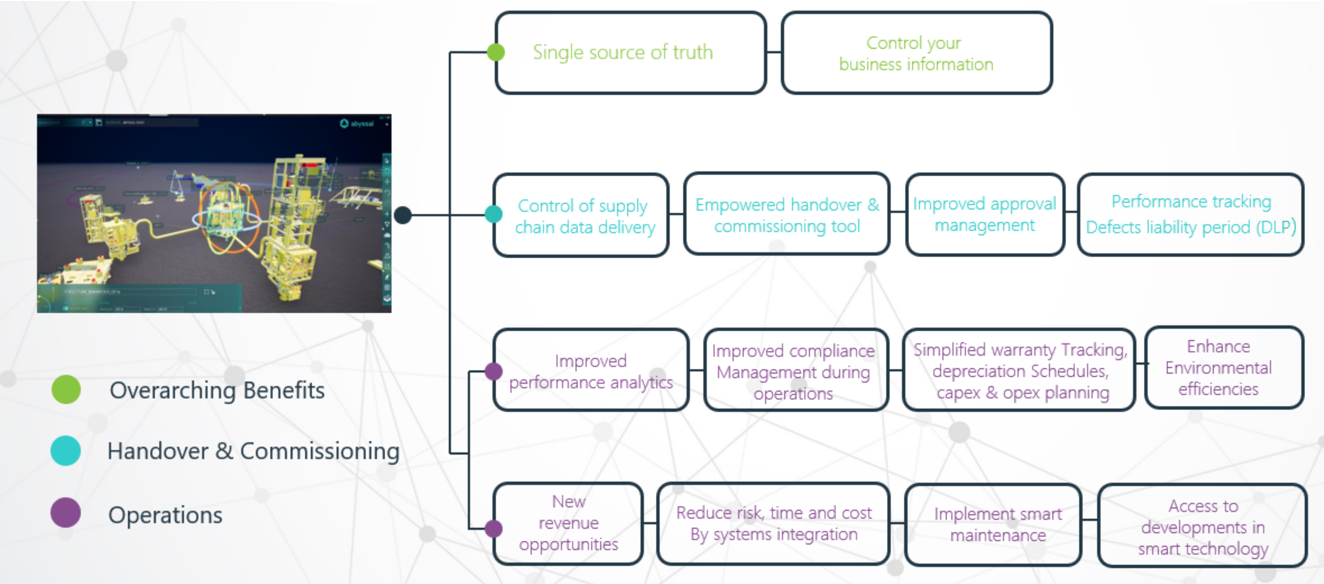

Figure 10-1 Digital Twin Full Asset Lifecycle

10.2.4 ROV Simulation

3D ROV simulation has enabled asset owners to design and plan subsea operational procedures in a 3D virtual environment. This technology is particularly useful for planning of non-routine subsea tasks, where access and manoeuvrability of the ROV needs to be confirmed. Instead of mobilising high risk and costly offshore campaigns, and potentially consuming resources on trial and error, engineers and related parties can run multiple simulations and increase the probability for successful execution of the actual subsea operation.

10.2.5 Computer Vision and Deep Learning for Automated Anomaly Detection

Computer vision and deep learning technologies aim to enable stakeholders to perform subsea anomaly detection based on a subsea survey. The technology will detect subsea objects, classifying features, and segmenting the asset based on location data. This technology aims to provide a more consistent and time effective anomaly detection based on specified anomaly criteria. Resources can be focused on reviewing and planning mitigation for critical anomalies.

10.2.6 Autonomous and Remote Controlled Subsea Inspection

Advancements in robotic and internet technologies are expected to enable stakeholders to operate autonomous and remotely operated subsea inspection vehicles. These technologies promise to significantly reduce resources traditionally required to mobilise subsea IMR campaigns.

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Appendix A Generic Unmitigated Threats Probability Assessment

Table A 1 Unmitigated Probability Assessment - Threats with potential for causing structural failures and loss of hydrocarbon containment

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	**Barrier Failure Mode**	**Barrier Failure Cause**	**Failure Mechanism**	**Record of Occurrence**	**Detection/ Observation (ref Table 7-1)**	**Highest Observation Accuracy**	**Consequence (seep, pinhole, leak, rupture)**	**Location (inside / outside 500m zone)**	**XMT/ Wellhead**	**Rigid Pipelines / Risers**	**Valves**	**Flexible Pipelines/Riser**	**Organisational Interface**	**Operational Interface**	**Technical Interface**
Internal Corrosion	1.Internal fluid induced corrosion, leakage, collapse or rupture 2. Sour fluid induced corrosion collapse or rupture	<u>Corrosion Inhibitor;</u> 1.a. Inefficient corrosion inhibitor 1.b. Unavailable corrosion inhibitor 1.c. Inhibitor dosing pump failure 1.d. Topside corrosion inhibitor leak <u>Internal coating/cladding, Operational Pigging, Flow management;</u> 1.e. Ratio flow assurance steady / unsteady state - excursions exceeding allowable 1.f. Monitored operating parameter excursions exceeding BOD values (Temperature, pressure CO_2, H_2S, water cut, Chlorides, iron counts, sulphide / sulphur, SRB counts, sand levels, mercury) 1.g. Water chemistry threshold value excursions exceeding BOD values: pH, dissolved oxygen, minimal microbial activity planktonic (in fluid), and sessile (at wall), organic acids, residual inhibitor concentrations 1.h. Wettability less efficient than assumed in BOD 1.i. Slug flow, accelerated fluid velocities / cavitation 1.j. Damage to scale film 1.k. Process upset/ ineffective dehydration 1.l. Inappropriate materials design <u>Fluid composition management;</u> 2.a. Reservoir souring above BOD 2.b. SRBs inhibition system not efficient 2.c. Inappropriate materials design	1. Localized corrosion or pitting of steel / Reduction in wall thickness / material loss on gasket or flange seal surface / Seal pressure capacity reduced 2. Inappropriate materials/ localized corrosion or pitting of steel / reduction in wall thickness	Happened to Operators	ILI UT Radiography Tracerco Visual Pressure loss recorded during pressure test.	Requires analyses of data	Pinhole, Leak, Seep	Along the pressurized system typically at horizontal sections and at 6 o'clock position. Areas of low flow or dead legs where debris can build up can be areas of higher probability.	H	H	M	L	Discipline Engineers	Design Fabrication Installation Operation Beyond Design Life	Corrosion Inhibitor injection system from topside to wells.

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	Barrier Failure Mode	Barrier Failure Cause	Failure Mechanism	Record of Occurrence	Detection/ Observation (ref Table 7-1)	Highest Observation Accuracy	Consequence (seep, pinhole, leak, rupture)	Location (inside / outside 500m zone)	XMT/ Wellhead	Rigid Pipelines / Risers	Valves	Flexible Pipelines/Riser	Organisational Interface	Operational Interface	Technical Interface
Erosion	1. Erosion induced leakage, collapse or rupture	Flow management, Debris monitoring: 1.a. Failure of down hole sand screens 1.b. Sand production levels greater than BOD levels 1.c. Excessive fluid velocity 1.d. Failure of monitoring equipment	1. Increased sand production/erosion of pipe wall/reduction in wall thickness	Anecdotal	ILI UT Radiography Tracerco Visual	Requires analyses of data	Pinhole, leak	Where flow is highest and at change of directions. Turbulent flow regions.	H	H	M	L	Discipline Engineers	Design Operation Beyond Design Life	Sand management in x-mas trees and topside valve
External Corrosion	1. Corrosion damage . leakage, collapse or rupture	Cathodic Protection (CP): 1.a. Non-isolated CP system and excessive drainage of current 1.b. accelerated consumption of anodes 1.c. Localized areas of CP isolation 1.d. Inadequate CP design 1.e. Damage to CP system caused by accidental damage 1.f. Dissimilar material and ineffective CP	1. Damage to coating / Damage to anode connections and/or continuity strap and/or /CP system/ CP ineffective / Galvanic corrosion/Localized corrosion or pitting of steel / Reduction in wall thickness and/or material loss on gasket or flange seal surface / seal pressure capacity reduced 2. For flexible pipe: Corrosive environment within annulus or exposure to oxygenated environment / ineffective CP / localised corrosion of metallic armouring / progressive corrosion / loss of armouring strength capacity / pipe rupture and leakage 3. Galvanic Corrosion	Happened to Operators	ILI Long Range UT Cathodic Protection monitoring Visual Inspection Magnetic stress measurement Eddy current inspection CVI	Accurate / Requires analyses of data	Pinhole. Leak. Rupture.	Splash zone and under deck air zone can be areas of concern. Beneath bending stiffener.	M	H	H	H	Discipline Engineers	Design Fabrication Installation Operation Beyond Design Life Risk increases in late life Lifetime extension	Cathodic protection interference between rigid risers and topside or pipelines.

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	Barrier Failure Mode	Barrier Failure Cause	Failure Mechanism	Record of Occurrence	Detection/ Observation (ref Table 7-1)	Highest Observation Accuracy	Consequence (seep, pinhole, leak, rupture)	Location (inside / outside 500m zone)	XMT/ Wellhead	Rigid Pipelines / Risers	Valves	Flexible Pipelines/Riser	Organisational Interface	Operational Interface	Technical Interface
Fatigue	1. Fatigue stress collapse or rupture 2. Pressure Induced Fatigue collapse or rupture 3. Corrosion Fatigue Stress collapse or rupture 4. HIC/SOHIC fatigue collapse or rupture 5. Pressure induced fatigue leakage	<u>Design, Pressure/temp monitoring, Span monitoring through GVI;</u> 1.a. Bottom currents exceeding BOD values 1.b. Wave action exceeding BOD (shallow waters) 1.c. Seabed erosion at span shoulders and change in VIV onset 1.d. Excessively long free spans 2.a. Flow induced pulsation (FLIP) 2.b. Slugging 2.c. Pressure cycling 2.d. Temperature cycling 3.a. Stress cycling 3.b. Corrosion environment 4.a. Excessive CP potentials 4.b. Coating breakdown 4.c. Inappropriate material 5.a. Flow induced pulsation (FLIP) 5.b. Slugging 5.c. Pressure cycling	1. Increased vortex induced vibration (VIV) / piping vibration / decreased fatigue life 2. Pipe vibration / fatigue of small bore piping 3. Localized corrosion (pitting) cause stress raisers/accelerate fatigue failure 4. Hydrogen Induced Cracking (HIC) or Stress Oriented Hydrogen Induced Cracking (SOHIC)/ Piping cracking 5. Pipe vibration / fatigue of small bore piping / seal pressure capacity reduced 6. For flexible pipe: Corrosion-fatigue environment within annulus or exposure to oxygenated or aggressive fatigue environment / localised fatigue of metallic armouring / loss of armouring strength capacity / pipe rupture and leakage	Happened to Operators	Visual inspection will show presence of spans or support degradation. ILI correctly specified can detect cracks before failure. Magnetic stress measurement Eddy current inspection. CVI	Accurate (spans/riser supports) Specialist techniques and equipment required. Can be difficult to pinpoint where to inspect for potential sites of fatigue damage. Requires analyses of data.	Leak, Rupture	Outside (ROV) for span related fatigue. Riser clamp supports can be inspected by ROV to verify support system intact. Splash zone and/or beneath bending stiffener.	L	M	M	H	Discipline Engineers	Design Fabrication Installation Operation Risk increases in late life Beyond Design Life and Lifetime extension	Floating unit offset

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	Barrier Failure Mode	Barrier Failure Cause	Failure Mechanism	Record of Occurrence	Detection/ Observation (ref Table 7-1)	Highest Observation Accuracy	Consequence (seep, pinhole, leak, rupture)	Location (inside / outside 500m zone)	XMT/ Wellhead	Rigid Pipelines / Risers	Valves	Flexible Pipelines/Riser	Organisational Interface	Operational Interface	Technical Interface
Flow Assurance / Flow Restrictions	1.Hydrate causing blockage 2.Wax causing blockage 3.Gel causing blockage 4.Scale causing blockage 5.Aspheltene causing blockage 6.Solids causing blockage 7.Intervention causing blockage 8.Change in reservoir condition	<u>Process conditions monitoring and control;</u> 1.a. Thermal insulation degradation or failure 1.b. Failure of deposit inhibition system 1.c.. Transient flow regime operating procedures ineffective 2.a. Thermal insulation degradation or failure 2.b. Ineffective chemical treatment 2.c. Transient flow regime operating procedures ineffective 3.a. Thermal insulation degradation or failure 3.b. Ineffective chemical treatment 3..c Transient flow regime operating procedures ineffective 3.d. Fluid Composition Changes <u>Inhibitor injection and control;</u> 4.a. Incompatibility of injection and formation water 4.b. Ineffective chemical treatment 4.c. Water chemistry change 4.d. Operational error on start-up or shut down 5.a. Pressure or temperature change due to primary reservoir depletion 5.b.Ineffective chemical treatment 5.c. Gas injection 5.d. Water injection 6.a. Solids (sand or proppant) production 6.b. Failure of sand screens 6.c. Low fluid velocity <u>Routine operational pigging;</u> 7.a. Pigging 7.b. Scale Squeeze 7.c. Other well intervention operations carried out from platforms via the flow lines	1.Temperature and pressure in hydrate formation range / water in fluids/ formation of hydrate/ reduced pipe bore/ low fluid velocity 2. Temperature below WAT / build-up of wax/ reduced pipe bore/ low fluid velocity 3. Temperature below gel formation point / gelling of fluid/ reduced pipe bore/ low fluid velocity 4. Injection of incompatible water / scale deposition/ reduced pipe bore/ low fluid velocity 5. Change in reservoir conditions / formation and deposition of asphaltenes/ reduced pipe bore/ low fluid velocity 6. Excessive solid production and low fluid velocity/ deposition of solids/ reduced pipe bore/ 7. Failure to use the correct pig or properly Qualified Pig Design	Happened to Operators	Process Monitoring	Threat observable through process data i.e. low/no flow, high/low pressure.	n/a	Various locations depending on process conditions.	H	H	H	M	Discipline Engineers	Design Operation Beyond Design Life and Lifetime extension	Direct Electrical Heating. Inhibitor injection and control.

wood.

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	Barrier Failure Mode	Barrier Failure Cause	Failure Mechanism	Record of Occurrence	Detection/ Observation (ref Table 7-1)	Highest Observation Accuracy	Consequence (seep, pinhole, leak, rupture)	Location (inside / outside 500m zone)	XMT/ Wellhead	Rigid Pipelines / Risers	Valves	Flexible Pipelines/Riser	Organisational Interface	Operational Interface	Technical Interface
Service Loads	1.Pipe local buckling collapse 2. Stress cycling leakage 3.High dynamic load leakage 4.High static load leakage	Design; 1. a. Bottom currents exceeding BOD values 1. b. Wave action exceeding BOD magnitude (shallow waters) 1. c Excessive residual stress post lay 1. d. Differential pressure 2. a. Increased Shutdown and Start-up Frequency 2. b. Stress cycle - physical displacement 3. a. Currents exceeding BOD values 3. b. Wave action exceeding BOD values 4. Differential settlement between subsea structures and pipelines	1.Increased span length due to seabed erosion / Pipe on sag bend is subjected to significant bending and combined loading, axial and external forces/ Pipe cross session in tension and compression/ Pipe deflects in order to relieve the stresses/ Higher stresses due to increased span length/ Ovalisation occurs to flatten areas under stress and reduce the bending stiffness of the pipe/ pipe buckles forming "pinching points" 2. Excessive pressure and temperature cycling / localized stress due to thermal cycling and restrained pipeline/ overstress / decreased fatigue life at connection 3. Excessive load at dynamic riser tie-in / localized damage and increased stress at connection 4. Excessive load on connection / localized damage and increased stress at connection	Anecdotal	Visual Inspection. Depth of Burial Survey.	Requires analyses of data	Leak, rupture	Inside and outside safety zone	L	M	M	M	Discipline Engineers	Design Installation Operation Beyond Design Life and Lifetime extension	Well workover
Temperature	1.High temperature deformation collapse or rupture 2. Low temperature collapse or rupture 3. Thermal expansion leakage	Design, Process monitoring and control; 1. Temperature above operating / design limit BOD 2. Temperature below operating / design limit BOD 3.a. Greater thermal loading than defined in BOD 3.b. Failure to Qualify to operating conditions	1.Excessively high fluid temperature and restrained piping/ piping expansion / excessive stresses 2.Excessively low temperature/ steel embrittlement / brittle fracture 3.Thermal expansion of line / localized damage and increased stress at connection 4. For flexible pipe: Excessively high fluid temperature / ageing embrittlement of chemical degradation / reduced elasticity and greater susceptibility to cracking / pipe leakage	Happened to Operators	Temperature Monitoring Polymer coupon monitoring	Requires analyses of data	Leak	Hottest location likely to be outside 500m zone, e.g. wellhead end.	L	L	M	H	Discipline Engineers	Design Operation Risk increases in late life Beyond Design Life and Lifetime extension	Start-up and shut-down procedures. Well workover. Direct Electrical Heating.

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	Barrier Failure Mode	Barrier Failure Cause	Failure Mechanism	Record of Occurrence	Detection/ Observation (ref Table 7-1)	Highest Observation Accuracy	Consequence (seep, pinhole, leak, rupture)	Location (inside / outside 500m zone)	XMT/ Wellhead	Rigid Pipelines / Risers	Valves	Flexible Pipelines/Riser	Organisational Interface	Operational Interface	Technical Interface
Pressure	1. Pressure build-up rupture 2. Pressure induced collapse 3. Pressure cycling collapse or rupture 4. Pressure build-up leakage	Design, Process monitoring and control; 1.a. Pipe Blockage and no pump trip in injection line 1.b Pressure exceeding BOD (WHSIP) 1.c HIPPS failure to activate 1.d. Pipe Ovality 2. Pressure below BOD limit 3. Increased Shutdown and Start-up Frequency 4.a. Pipe Blockage and no pump trip in injection line 4.b. Pressure exceeding BOD (WHSIP) 4.c. HIPPS failure to activate	1. Excessive internal/external differential pressure / piping overstress/ excessive accumulated plastic strain. 2. Excessive external/ internal differential pressure / Loss of structural capacity. 3. Stresses due to fluctuating pressure and temperature / Ratcheting / Excessive accumulated plastic strain. 4. Excessive internal/external differential pressure / connector overstress/ excessive accumulated plastic strain/ seal pressure capacity reduced.	Happened to Operators	Pressure Monitoring	Requires analyses of data	Rupture, leak	Inside and outside safety zone	L	M	M	M	Discipline Engineers	Design Operation Beyond Design Life	Pressure sources including chemical injection and inhibition systems. Safety Instrumented Systems. Well workover.
Accidental Damage	1.External damage collapse or rupture 2. External damage collapse or rupture	Design, Increased awareness of 3rd parties; 1.a. Dropped objects due to 3rd party 1.b. Anchors and mooring vessels 1.c. Dragged line 1.d. ROV impact 1.e. Natural disaster (iceberg interaction, storm, etc) 1.f. Trawl board/fishing activity 1.g. Installation impact 2. Pigging induced internal damage	1.Deformation or over stress due to localized impact 2.Internal coating/cladding damage/Corrosion/Reduction in wall thickness/material loss on gasket or flange seal surface / seal pressure capacity reduced	Happened to Operators	Accidental damage cannot be predicted by inspection. Only able to be inspected after damage has occurred.	Accurate	Leak	More probable away from 500m zone as access to this area is controlled from platform.	L	H	M	H	Discipline Engineers	Design Installation Operation Beyond Design Life and Lifetime extension	Marine operations. Fishing and trawling activities.

Barrier Threats Identification				Observability and Consequence of Failures for High Unmitigated Probabilities Threats					Unmitigated Probability Assessment				Interfaces		
Threats	**Barrier Failure Mode**	**Barrier Failure Cause**	**Failure Mechanism**	**Record of Occurrence**	**Detection/ Observation (ref Table 7-1)**	**Highest Observation Accuracy**	**Consequence (seep, pinhole, leak, rupture)**	**Location (inside / outside 500m zone)**	**XMT/ Wellhead**	**Rigid Pipelines / Risers**	**Valves**	**Flexible Pipelines/Riser**	**Organisational Interface**	**Operational Interface**	**Technical Interface**
Manufacturing / Quality	1.Material defect leakage, collapse or rupture 2. CP accelerated hydrogen induced cracking collapse or rupture 3. Incorrect preservation causing structural failure or leakage 4.Construction or fabrication yards with lack of experience with relevant authority regulation and project specific specifications and standards 5.Lack of qualification of manufacturer 6. Lack of traceability of raw materials 7. Welding shortcomings 8. Damage or shortcomings during assembly (e.g. Bolt torque or physical damage) 9. Coating application	Design, QA/QC during manufacture, Inspection; 1.a. Material and Weld Defects 1.b.. Regions of high SCF in weld 1.c. Weld Internal Misalignment 1.d. Weld Microstructure 1.e. Inappropriate welding consumables 1.f. Ineffective chemical treatment" 2.a. Material and Weld Defects, high number of inclusions 2.b. Material has high hardness value" 3. Incorrect storage/ maintenance during storage	1. Increased stress at defect/ loss of wall thickness at weld/ piping cracking. 2. Increased rate of hydrolysis / hydrogen bubble formed at inclusion or hydrogen collection at defect / high pressure build-up at localized defect site / piping cracking. 3.Material Degradation/ Loss of structural integrity.	Happened to Operators	Manufacture Quality Management i.e. Manufacture Inspection and Testing Record	Requires analyses of data	Depends on defects during manufacture	Inside and outside safety zone	L	M	M	L	Discipline Engineers Fabricators and manufacturers	Fabrication Installation	Cathodic protection. Material selection. System spec breakes.
Installation	Design Installation QA/QC 1. Installation damage 2. Installation Off Location 3. Connector unlock leakage 4.Transportation 5.Assembly shortcomings	1.a. Excessive time hung off at tensioners and higher accumulated fatigue 1.b. Pipe ovality induced during lay 1.c. Trenching / Ploughing activities 2.a. Improper Survey 2.b. Soil conditions inadequate 3. Connector unlock or failure to lock	1.Damage or over stress to piping/ reduction of structural capacity 2.Off location altering field architecture 3.Leakage due to poor connection make-up	Happened to Operators	Pre and Post Installation Survey	Requires analyses of data	Leak, rupture	Along the pipeline	M	M	M	H	Discipline Engineers Installation Contractors Marine organisation	Installation	Subsea wet parking preservation. New and diverse installation technology. Connection between components designed and fabricated using different code, standard or specification

wood.

Appendix B Standard List and Applicability

Table B 1 Integrity and Design Code and Standard List

Standard Code Name	Revision*	Applicability				
		General	Rigid Pipeline and Riser	Flexible Pipeline and Riser	XMT/ Wellhead	Valves
Integrity						
API RP 17A Recommended Practice for Design and Operation of Production Systems	5th Ed, May 2017	•			•	•
API RP 17N Recommended Practice for Subsea Production System Reliability and Technical Risk Management	2nd Ed, June 2017	•				
API RP 17V Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Subsea Applications	1st Ed, March 2015	•				
API RP 75 Recommended Practice for a Safety and Environmental Management System for Offshore Operations and Asset	4th Ed, Dec 2019	•				
DNVGL-RP-0002 Integrity Management of Subsea Production System	September 2019	•				
DNV-RP-F116 Integrity Management of Submarine Pipeline Systems	September 2019		•			
DNV-RP-F206 Riser Integrity Management	September 2019			•		
ISO 13628 Petroleum and natural gas industries - Design and operation of subsea production systems. Various Parts	Various	•				
ISO 19345-2 Petroleum and natural gas industry — Pipeline transportation systems — Pipeline integrity management Specification — Part 2: Full-life cycle integrity management for offshore pipeline	1st Ed, May 2019		•			
ISO 20815 Petroleum, petrochemical and natural gas industries — Production assurance and reliability management	2nd Ed, Oct 2018	•				
NORSOK U-009 Lifetime extension for subsea systems	1st Ed, March 2011	•				
NORSOK Y-002 Lifetime extension for transportation systems	1st Ed, Dec 2010	•				
NORSOK D-010 Well integrity in drilling and well operations	4th Rev, June 2013				•	•
API RP 580 Risk Based Inspection	3rd Edition, February 2016	•	•			
API RP 581 Risk Based Inspection Methodology	3rd Edition, April 2016	•	•			
API RP 1160 Managing System Integrity for Liquid Pipelines	3rd Edition, February 2019		•			
ASME B31.8S	Nov 2018		•			

Standard Code Name	Revision*	Applicability				
		General	Rigid Pipeline and Riser	Flexible Pipeline and Riser	XMT/ Wellhead	Valves
Managing System Integrity of Gas Pipelines						
BSI PD 8010 Part 4 Steel Pipelines and Land and Subsea Pipelines- Code of Practice for Integrity Management	July 2012		•			
ISO TS 12747 Petroleum and Natural Gas Industries – Pipeline Transportation Systems - Recommended Practice for Pipeline Life Extension	1st Edition, April 2011		•			
Design						
API 17 J Specification for Unbonded Flexible Pipe	4th Ed, May 2014			•		
API 17 B Recommended Practice for Flexible Pipe	5th Ed, May 2014			•		
DNVGL-ST-F201 Riser System	Jan 2020			•		
DNVGL-ST-F101 Submarine Pipeline Design	Oct 2017		•			
ISO 13623 Petroleum and natural gas industries — Pipeline transportation systems	3rd Ed, Sept 2017		•			
NORSOK U-001 Subsea Production System	4th Ed, Oct 2015	•				
ISO 13628 Petroleum and natural gas industries - Design and operation of subsea production systems. Various Parts.	Various	•				
Norsok D-001 Drilling Facilities	3rd Ed, Jan 2013				•	•
DNVGL-OS-E101 Drilling Facilities	Jan 2018				•	•
API 17 D Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment	2nd Ed, May 2011				•	•
ISO 16530-1 Petroleum and natural gas industries — Well integrity — Part 1: Life cycle governance	March 2017				•	•
API Spec 6A Specification for Wellhead and Tree Equipment	21st Ed, Nov 2019				•	•
API Spec 14A Specification for Subsurface Safety Valve Equipment	12th Ed, 2015				•	
API RP 14B Design, Installation, Repair and Operation of Subsurface Safety Valve Systems	6th Ed, Nov 2015				•	
API Std 6AV2 Installation, Maintenance, and Repair of Safety Valves (SSV, USV, and BSDV)	2nd Ed, Aug 2020				•	
API Std 598 Valve inspection and testing	10th Ed, Oct 2016				•	

*Note: (as per 2020)