Draft for Public Comment

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Interested committees:

Title: Draft BS ISO 19345-1 Petroleum and natural gas industry - Pipeline transportation systems - Pipeline integrity management specification. Part 1: Full-life cycle integrity management for onshore pipeline.

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Introduction

This draft standard is based on national and international discussions. Your comments on this draft are invited and will assist in the preparation of the consequent standard.

For international standards, comments will be reviewed by the relevant UK national committee before sending the consensus UK vote and comments to the international committee, which will then decide appropriate action. If the international standard is approved, it is usual for the text to be published as a British Standard.

For national standards, comments will be reviewed by the relevant UK national committee and the resulting standards published as a British Standard.

UK Vote

Please indicate whether you consider the UK should submit a negative (with supporting technical reasons) or positive vote on this draft. Please indicate if you are aware of any reason why this draft standard should not be published as a British Standard.

Submission of Comments

- **Annotated drafts are not acceptable and will be rejected.**
- All comments should be submitted online at **https://standardsdevelopment.bsigroup.com/**. You will need to register in order to comment.

Template for comments and secretariat observations

Date: xx/xx/20xx	Document: ISO/DIS xxxx

1	2	(3)	4	5	(6)	7
MB	Clause No / Subclause No /Annex **(e.g. 3.1)**	Paragraph/Figure/ Table/Note	**Type of comment**	**Commend (justification for change) by the MB**	**Proposed change by the MB**	**Secretariat observations on each comment submitted**
	3 1	Definition 1	ed	Definition is ambiguous and needs clarifying	Amend to read ' so that the mains connector to which no connection '	
	6 4	Paragraph 2	te	The use of the UV photometer as an alternative cannot be supported as serious problems have been encountered in its use in the UK	Delete reference to UV photometer	

DRAFT INTERNATIONAL STANDARD
ISO/DIS 19345-1

ISO/TC **67**/SC **2** Secretariat: **UNI**

Voting begins on: **2017-12-08** Voting terminates on: **2018-03-02**

Petroleum and natural gas industry — Pipeline transportation systems — Pipeline integrity management specification —

Part 1: **Full-life cycle integrity management for onshore pipeline**

PNGI — Spécifications de gestion de l'intégrité des pipelines —

Partie 1: Gestion de l'intégrité des pipelines terrestres durant leur cycle de vie complet

ICS: 75.200

Reference number
ISO/DIS 19345-1:2017(E)

Contents

Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

The procedures used to develop this document and those intended for its further maintenance are described in the ISO/IEC Directives, Part 1. In particular the different approval criteria needed for the different types of ISO documents should be noted. This document was drafted in accordance with the editorial rules of the ISO/IEC Directives, Part 2 (see www.iso.org/directives).

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. ISO shall not be held responsible for identifying any or all such patent rights. Details of any patent rights identified during the development of the document will be in the Introduction and/or on the ISO list of patent declarations received (see www.iso.org/patents).

Any trade name used in this document is information given for the convenience of users and does not constitute an endorsement.

For an explanation on the meaning of ISO specific terms and expressions related to conformity assessment, as well as information about ISO's adherence to the World Trade Organization (WTO) principles in the Technical Barriers to Trade (TBT) see the following URL: www.iso.org/iso/foreword.html.

This document was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for the petroleum, petrochemical and natural gas industries*, Subcommittee SC 2, *Pipeline transportation systems*.

A list of all parts in the ISO 19345 series can be found on the ISO website.

Introduction

This document addresses the integrity of petroleum and natural gas pipelines through their entire life-cycle, from design to eventual abandonment. For this reason, considerations relating to design, construction, and abandonment have been included. This approach supports the development and implementation of a holistic and integrated pipeline integrity management program that bridges between life-cycle elements and thereby avoids compartmentalizing of the pipeline life-cycle into essentially independent data and functional silos, which traditionally has been the case. The integrated approach was developed on the basis of extensive research and examination of best practices and results from pipeline integrity audits world-wide. This document incorporates a combination of prescriptive and performance based requirements. In some cases where there are prescription requirements, it provides the user the option to arrive at a solution using performance based requirements. However, the level of safety achieved by following the prescriptive requirements gives the minimum performance based requirements. The ability to use performance based solutions allows companies to use new equipment or innovative practices to achieve the same goal. This document is intended to be used by companies that have not yet developed an official program or are developing a program for new pipelines. This document can also be used for continual improvement of existing programs by both operating companies and regulators to evaluate integrity management program effectiveness.

Petroleum and natural gas industry — Pipeline transportation systems — Pipeline integrity management specification —

Part 1:
Full-life cycle integrity management for onshore pipeline

1. Scope

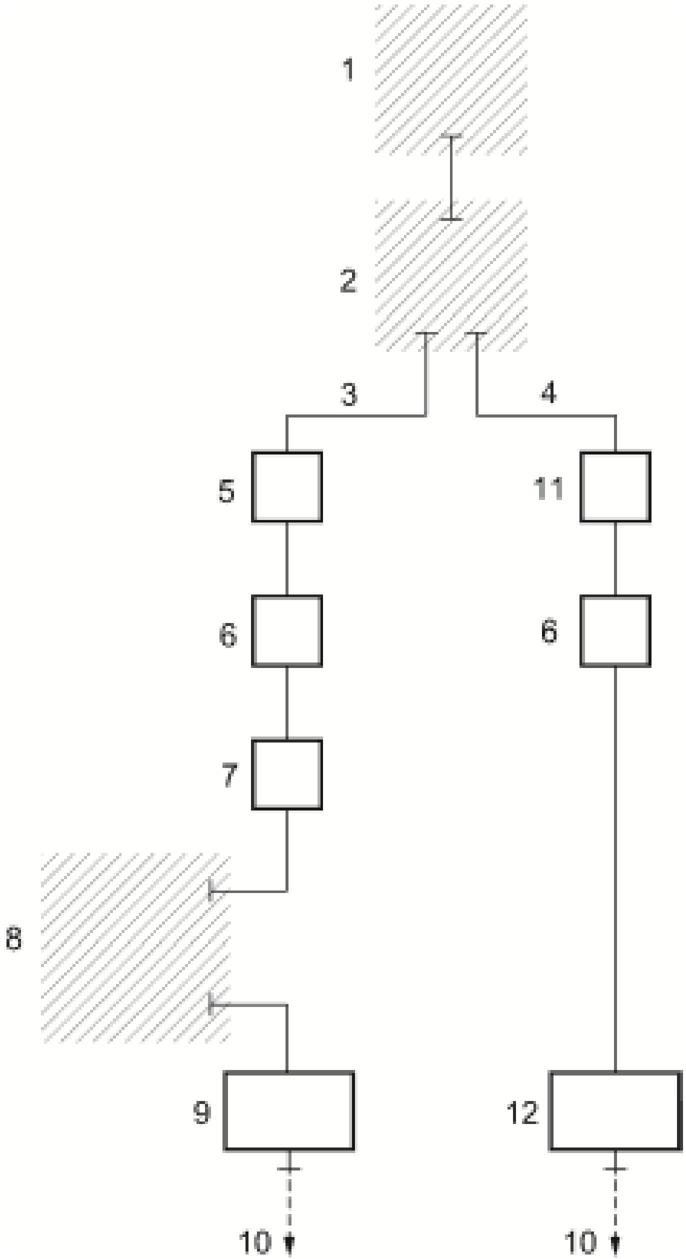
1.1 This document specifies requirements and gives recommendations on the management of integrity of a pipeline system through the life cycle, which includes design, construction, commissioning, operation, maintenance and abandonment.

1.2 This document applies to onshore pipeline systems used in transportation in the petroleum and natural gas industries, connecting wells, production plants, process plants, refineries and storage facilities, including any section of a pipeline constructed within the boundaries of such facilities for purpose of its connecting. The extent of pipeline systems covered by this document is illustrated in Figure 1. This document does not deal specifically with the integrity of non-pipe elements. The pipeline segment between the wellsite and the gathering station, treatment plant or process plant (between Facilities 1 and 2 in Figure 1) is included in this document, though many mandatory elements of this document are not practical due to characteristics such as diameter, operating parameters, etc. The requirements of this document are to be complied where feasible, or by other methods that provide for the operation of the pipeline without impacting safety or the environment.

1.3 This document applies to rigid, steel pipelines. It is not applicable for flexible pipelines or those constructed from other materials, such as glass-reinforced plastics.

1.4 This document does not cover all conditions and engineers competency in pipeline integrity. Whether additional requirements are warranted should be evaluated.

1.5 This document is used for integrity management, which is initiated at the design and construction stage of the pipeline. The design and construction of the pipeline is in accordance with a recognized design and construction standard that provides guidance related to safe operation of the pipeline. Where requirements of the design and construction standard are differentiate from this document, provisions of this document prevail.



Key

1 wellsite
2 gathering station, treatment plant or process plant
3 liquid
4 gas
5 pump station
6 valve station
7 tankage
8 refinery
9 depot
10 distribution
11 compressor station
12 pressure-reduction station

Pipeline elements covered by this document.

Connections with other facilities.

Pipeline elements not covered by this document.

Station/plant area covered by this document.

Figure 1 — Extent of pipeline systems covered by this document

2. Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

ISO 13623:2009, *Petroleum and natural gas industries — Pipeline transporting system*

ISO 15589-1:2015, *Petroleum, petrochemical and natural gas industries — Cathodic protection of pipeline systems — Part 1: On-land pipelines*

ISO 31000, *Risk management— Principles and guidelines*

IEC 31010, *Risk assessment techniques*

NACE SP0169, *Control of external corrosion on underground or submerged metallic piping systems*

3. Terms, definitions and abbreviated terms

3.1 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

— ISO Online browsing platform: available at http://www.iso.org/obp

— IEC Electropedia: available at http://www.electropedia.org/

3.1.1
abandonment
activities associated with taking a pipeline permanently out of operation

Note 1 to entry: An abandoned pipeline cannot be returned to operation.

Note 2 to entry: Depending on the legislation abandonment can require cover or removal.

3.1.2
anomaly
possible deviation from pipe material or weld soundness

Note 1 to entry: The identification of an indication of an anomaly can be generated by non-destructive inspection, such as in-line inspection.

3.1.3
baseline assessment
first integrity assessment prior to or after commission

3.1.4
cathodic protection
corrosion control technique to prevent or reduce the corrosion of underground metal pipelines by transferring an electrical current onto the pipe to achieve higher electrical potentials

3.1.5
corrosion
deterioration of a material, usually a metal that results from an electrochemical reaction with its environment

3.1.6
crack
planar flaw, or linear discontinuity, with a sharp tip radius

3.1.7
critical consequence area
location where a pipeline release might have a significant adverse effect on public safety, property and the environment

Note 1 to entry: The location and scope of critical consequence areas will change over time as new population and environmental resource data becomes available. The pipeline segments in CCAs are of particular interest in risk assessment and integrity assessment evaluations and prioritizations.

3.1.8
deactivation
remove from service, can return to service after proper assessment, also defined as decommissioning or suspension

3.1.9
deformation
change in shape of the pipe or component, such as a bend, buckle, dent, ovality, ripple, wrinkle, or any other change that affects the roundness of the pipe or component's original cross-section or straightness of the pipe or component

3.1.10
defect
imperfection of a type or magnitude exceeding acceptable criteria

3.1.11
dent
depression which produces a disturbance in the curvature of the pipe wall, caused by contact with a foreign body resulting in plastic deformation of the pipe wall

3.1.12
design life
period for which the design basis is planned to remain valid

[SOURCE: ISO 13623:2009, 3.1.2]

3.1.13
external corrosion direct assessment
integrity assessment process for locating possible external corrosion, damaged coating, or deficiencies in cathodic protection on a pipeline by making aboveground measurements and validating with excavations to examine the pipe where appropriate

3.1.14
failure
event in which a component or system does not perform according to its operational requirements

3.1.15
fitness for purpose
quantitative engineering evaluation that is performed to demonstrate the structural integrity of an in-service component that can contain an imperfection, defect or damage

3.1.16
gouge
surface damage to a pipeline caused by contact with a foreign object that has scraped (gouged) material out of the pipe, resulting in a metal loss defect or imperfection

3.1.17
hard spot
localized increase in hardness through the thickness of a pipe, produced during hot rolling or welding

3.1.18
incident
unintentional release of gas or liquid due to the failure of a pipeline

Note 1 to entry: Some regulatory authorities have defined incident differently. In these cases, an incident can be defined as an event occurring on a pipeline for which the operator shall make a report to the concerned regulatory authority.

3.1.19
in-line inspection
inspection of a pipe wall from the interior of the pipe using specialized tools

3.1.20
integrity assessment
process that includes inspection and test of pipeline to obtain the pipe body's information, combining analysis of material and structure's reliability, evaluating the safety state of the pipeline, so as to determine the applicability of it

3.1.21
integrity management program
documented program that specifies the practices used by the operating company to proactively manage the safe, environmentally responsible, and reliable service of a pipeline system throughout its lifecycle that incorporates a continual improvement process

3.1.22
life extension
additional period of time beyond the original design or service life (but within the assessed remnant life) for which permission to continue operating a pipeline system is granted by the regulatory bodies

Note 1 to entry: Life extension is considered as a modification to the design basis.

[SOURCE: ISO/TS 12747:2011, 3.7]

3.1.23
location class
geographic area classified according to criteria based on population density and human activity

[SOURCE: ISO 13623:2009, 3.1.10]

3.1.24
magnetic flux leakage
type of in-line inspection technology in which a magnetic field is induced in the pipe wall between two poles of a magnet

Note 1 to entry: Anomalies affect the distribution of the magnetic flux in the wall. The magnetic flux leakage pattern is used to detect and characterize anomalies.

3.1.25
management of change
process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural, or organizational nature that can impact system integrity

3.1.26
manufacturing defect
defect in the pipe body or coating created during the pipe or component manufacturing or coating processes

3.1.27
maximum allowable operating pressure
maximum pressure at which the pipeline system, or parts thereof, is allowed to be operated and usually determined by hydrostatic tests and a corresponding safety factor associated with the fluid transported within a given location class area

3.1.28
metal loss
pipe anomaly in which metal has been removed

Note 1 to entry: Metal loss is usually the result of corrosion, but gouging, manufacturing defects, or mechanical damage can also result in metal loss.

3.1.29
non-destructive testing
wide group of analysis techniques used to evaluate the properties of a material, component or system without causing damage

Note 1 to entry: The terms non-destructive inspection (NDI) and non-destructive evaluation (NDE) are also commonly used to describe this technology.

3.1.30
operator
person or organization who owns or operates a pipeline system or facilities and is ultimately responsible for the operation and integrity of the pipeline system

3.1.31
pipeline
components of a pipeline system connected together to convey fluids between stations and/or plants, including pipe, launchers and receivers, components, appurtenances, isolating valves, and sectionalising valves.

3.1.32
pipeline integrity management
set of processes and procedures that proactively ensures incident-free transportation of fluids through a pipeline system

3.1.33
pipeline integrity management program
continual improvement closed-loop system using information technology to realize functions, such as data acquisition and integration, integrity and risk assessment, mitigation and repair activity and maintenance decisions, with comprehensive management of change and continual review and improvement processes

3.1.34
pressure test
means of assessing the integrity of a new or existing pipeline that involves filling the pipeline with water and pressurizing to a level reasonably in excess of the MAOP of the pipeline to demonstrate that the pipeline is fit for service at the MAOP for a given time frame dependent on the identified integrity hazards

3.1.35
risk
measure of loss, either qualitative or quantifiable, in terms of both the likelihood of incident occurrence and the magnitude of the consequences of the incident occurrence

3.1.36
risk assessment
systematic, analytical process in which potential hazards from pipeline system are proactively identified, and the likelihood and consequences of potential adverse events are determined

3.1.37
risk management
coordinated activities to direct and control an organization with regard to risk

[SOURCE: ISO Guide 73:2009, 2.1]

3.1.38
safe operating pressure
pressure, calculated using remaining strength of corroded pipeline formulas, where all corroded regions will withstand a pressure equal to a stress level of certain times of the MAOP according to different safety factors or formula chosen

3.1.39
service life
length of time over which the pipeline system is intended to operate

Note 1 to entry: Service life is considered the actual operational life to date, but can include any planned future use of the line. Service life can be less or longer than design life.

[SOURCE: ISO/TS 12747:2011, 3.21]

3.1.40
sizing accuracy
accuracy with which an anomaly dimension or characteristic is reported

Note 1 to entry: Typically, accuracy is expressed by tolerance and certainty. As an example, depth sizing accuracy for metal loss using NDT methods, such as an ILI tool, is commonly expressed as +/-10 % of the wall thickness (the tolerance) and 80 % of the time (the certainty).

3.1.41
third party damage
damage done to the pipeline as a result of activities by personnel not associated with the pipeline

3.1.42
threat
activity or condition than can adversely affect the pipeline system if not adequately controlled

[SOURCE: ISO/TS 12747:2011, 3.23]

3.2 Abbreviated terms

AC	alternating current
CP	cathodic protection
CCA	critical consequence area
CoF	consequence of failure
DA	direct assessment
ECDA	external corrosion direct assessment
FFP	fitness for purpose
GIS	geographic information system
HIC	hydrogen-induce cracking
ICDA	internal corrosion direct assessment
ILI	in-line inspection
IMP	integrity management program
MAOP	maximum allowable operating pressure
MFL	magnetic flux leakage
NDT	non-destructive testing
PIM	pipeline integrity management
PIR	potential impact radius
PoF	probablity of failure
SCADA	supervisory control and data acquisition system
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SMYS	specified minimum yield strength
SSC	sulfide-stress cracking

4. General

4.1 Key principles

The operator uses integrity management programs (IMPs) to enable them to manage its pipeline systems in a safe, environmentally responsible and reliable manner. An effective IMP anticipates and mitigates or eliminates integrity issues before they lead to incidents or failures.

Key principles for an effective IMP are listed below:

a) Pipeline integrity requires a lifecycle approach from initial feasibility studies to abandonment.

b) Adequate resources in terms of funds, equipment and competent personnel to implement the requirements of the IMP are necessary.

c) Clearly defined roles and responsibilities with clear communication processes are necessary.

d) Document management including gathering and retention requirements are critical elements that enable informed decisions.

e) Performance measures of the IMP's effectiveness should include both leading and lagging indicators to identify trends and areas for continuous improvement.

f) An effective IMP is risk based and may be used to prioritize integrity related actives.

4.2 Integrity management program

4.2.1 General

The IMP forms part of a comprehensive asset management system operating alongside safety and environmental programs. The operator shall establish, implement and maintain a documented IMP, and routinely review and improve its adequacy.

To facilitate the development and implementation of the initial IMP for a pipeline system, the operator shall develop processes for initial data acquisition, threat and consequence identification and risk assessment at the design stage. The initial IMP will be updated and improved throughout the lifecycle of the asset.

4.2.2 Introduction to integrity management program elements

The pipeline IMP shall address the operator's approach to the following elements, see Figure 2:

a) Life cycle phases for integrity management

Integrity shall be applied through the entire life cycle of pipeline, including:

— feasibility;

— design;

— procurement;

— fabrication;

— transportation and storage;

— construction;

— pre-commissiong and commissioning;

— handover;

— operation and maintenance;

— modification;

— suspension/abandonment.

b) Pipeline integrity management process

As part of the continual improvement process, the inputs into these elements shall be routinely updated, as required, to reflect the dynamic nature of pipeline systems:

— data management (data acquisition, review and integration);

— risk assessment (threat, consequence, probability, CCA);

— inspection;

— integrity assessment;

— mitigative activity;

— performance measurement and improvement.

NOTE 1 Understanding the pipeline's integrity and threats in the context of the surrounding environment is key to making informed integrity management decisions.

NOTE 2 Performance measurement can verify that the goals, targets and objectives of the integrity program are being met and can be used during management reviews to identify improvement opportunities.

The following elements shall be developed for to the operational phase to ensure that adequate management practices are in place to assess failures and manage and respond to emergencies:

— failure assessment plan;

— emergency response plan;

— remaining life assessment plan.

NOTE 3 The failure assessment plan considers failure causes and contributing factors and provides critical information to the IMP. The goal is to prevent reoccurrence of similar failures.

NOTE 4 The emergency response plan is designed to ensure the operator is prepared to deal with accidents and incidents in a timely manner to aid in the reduction of consequences. These accidents or incidents can occur, because the IMP did not foresee or was unable to effectively mitigate the threat.

NOTE 5 The remaining life assessment provides input into the economic viability assessment of the pipeline. As the pipeline ages, the operational risks and mitigation costs increase until continuing the operation is no longer viable.

c) Management elements

The following elements shall form part of an IMP and may be written to encompass more than one pipeline or system. These elements usually interact with other management systems within an organization:

— policy and commitment;

— scope of the IMP;

— organizational structure including key roles and responsibilities.

The following mandatory elements predominately deal with information flow, providing the core of the data system providing information for assessment and review. They are usually presented as plans with procedures:

— communication;

— records and documents management;

— management of change;

— management review and audit;

— training and competency.

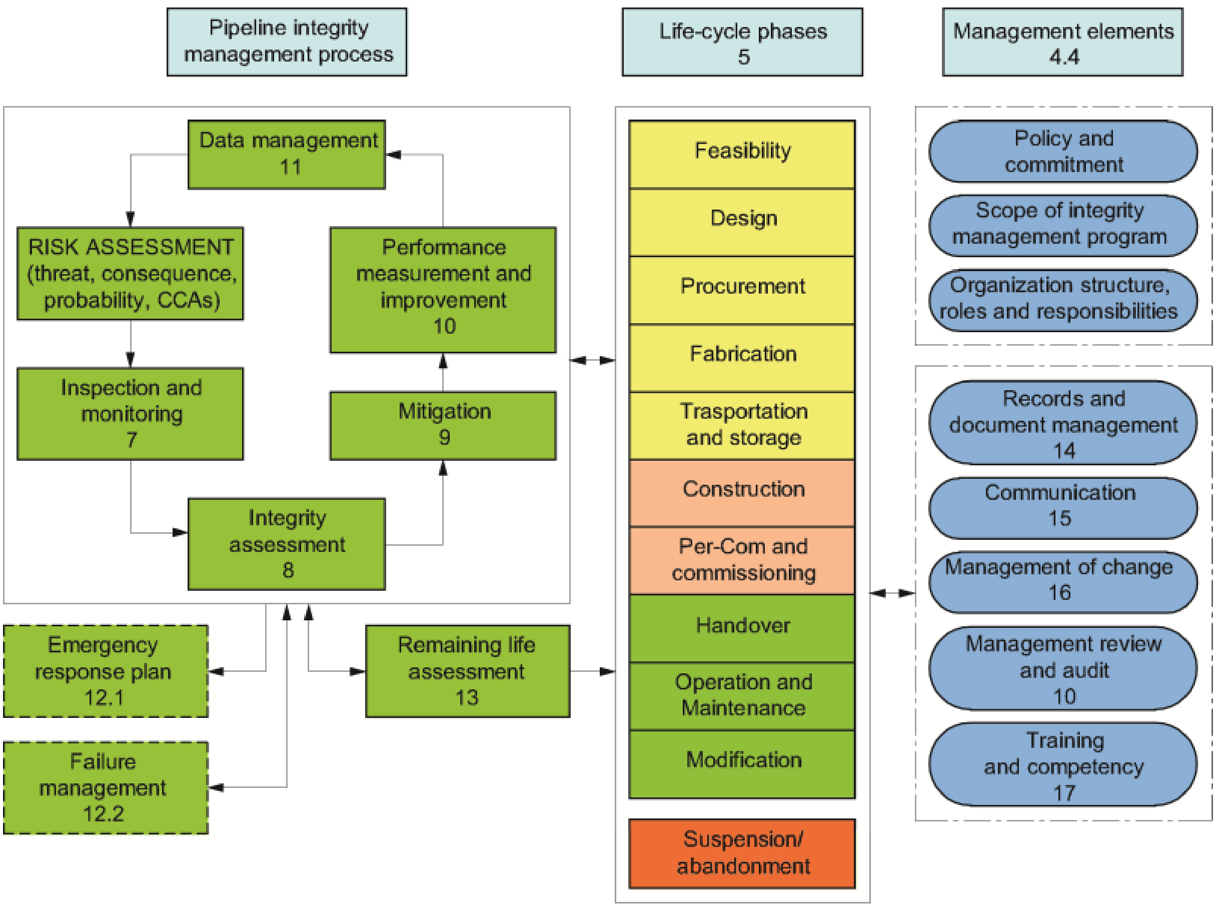


Figure 2 — Pipeline integrity management program structure

4.3 Integrity management process elements

4.3.1 Data management

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segments and the potential threats to that segment. A plan for collection of historical data shall be established and maintained for the pipeline system lifecycle. The operator shall perform the initial collection, review and integration of relevant data and information from pipeline design, construction, operation, maintenance, patrolling and failure investigation data. Data acquisition is needed to understand the condition of the pipe; identify the location-specific threats to its integrity; and understand the public, environmental, and operational consequences of an incident.

4.3.2 Risk assessment

Risk analysis is an analytical process through which the operator considers the likelihood threats occurring and the nature and severity of the resulting consequences.

Risk assessment shall be performed for all scenarios including low consequence—high likelihood and critical consequence—low likelihood events. Every plausible failure mode shall be listed and assigned probability and consequence values. Where multiple consequences occur from a single failure mode multiple assessments are required.

The operator shall consider all of the threats and any interactive threats that can be applicable to its system. It can be appropriate to consider risks in pipeline segments where the consequence of failure is particularly high and where explicit integrity management measures have to be implemented.

Risk assessment shall be reviewed at regular intervals, and when substantial changes occur to the pipeline. The assumptions and variables used in the consequence analysis shall be updated as part of the review.

4.3.3 Inspection and monitoring

The operator shall select and conduct appropriate inspection and monitoring based on the risk assessment made in the previous step, typically include in-line inspection, pressure testing, direct assessment, or other inspection and monitoring methods based upon the threats that have been identified. More than one inspection or monitoring method can be required to address all the threats to a pipeline segment.

4.3.4 Integrity assessment

Integrity assessment will implement the following hierarchy of controls:

— elimination;

— physical controls;

— procedural controls.

Where risks cannot be sufficiently controlled, mitigation activities shall be implemented until the risk is considered satisfactory.

The process of establishing and implementing effective preventive and mitigation measures requires suitable data collection, data integration, and informational analysis within the IMP. Data integration and the analysis can identify aspects of the operator's operations and maintenance that allow the operator to address the threats. Most importantly, local knowledge of the operational environment around the pipeline and the incident history associated with certain components or circumstances should be considered.

4.3.5 Mitigative activity

Where a threat cannot be controlled, the operator shall develop appropriate actions to mitigate the threat to an acceptable level of risk.

The results of mitigation assessments shall be used to determine what additional prevention or mitigation measures are required to reduce unacceptable risks identified in the assessment. Prevention and mitigation activities should be applied to reduce the likelihood of failure and/or the consequence of the failure to an acceptable level. Preventative measures typically involve activities to reduce the likelihood of an event.

The operator shall perform mitigation activities to ensure the pipeline system remains safe for its intended service. Where applicable, these mitigation activities shall provide a factor of safety that is notionally similar to the design factor of safety (e.g. achieved through an applicable hydrostatic strength (proof) test of the pipeline). This notional equivalent design factor of safety shall be maintained throughout the life of the pipeline. The mitigation activities can include activities such as increased surveillance and pressure reductions.

4.3.6 Performance measurement and improvement

The operator shall develop procedures to regularly measure and evaluate the adequacy of implementation and effectiveness of IMP and its compliance to relevant regulations and standards.

The operator shall also evaluate the effectiveness of its other related management programs and processes in supporting integrity management decisions.

A combination of performance measures and system audits can be necessary to evaluate the overall effectiveness of a pipeline integrity system.

Performance measurement results shall be used to continuously identify areas for improvement of the IMP. In addition, advances in technology and industry best practices shall be considered.

4.3.7 Emergency response plan

Plans and response procedures for emergency situations shall be established and maintained based on a systematic evaluation of possible scenarios that can affect the safe and reliable operation of the pipeline system. Plans and procedures for contingency repair of the pipeline shall be established depending on the criticality of the pipeline system, based on factors such as safety, environmental, legislative or commercial considerations.

4.3.8 Failure management plan

The operator shall develop procedures for pipeline failure investigation to ensure that a structured approach is adopted and all aspects reviewed. The failure investigation shall aim to determine the root cause of a pipeline failure and recommend corrective actions to prevent similar failures. This can include a targeted risk management program for causes that are not isolated. The operator shall setup a database to record relevant pipeline failure information to support failure management.

4.3.9 Remaining life assessment

The operator shall develop remaining life assessment for all pipeline segments and systems and update them as new integrity information is gathered, e.g. ILI. The remaining life assessment shall be reviewed at regular intervals, at the end of the design life and after pipeline failures.

The remaining life assessment will be used to enable lifecycle management processes to balance the risks of ongoing operation with safety and protection of the environment and associated costs of operations and management.

4.4 Management elements

4.4.1 Policy and commitment

The operator shall have a policy that expresses management commitment for developing, implementing, reviewing and continual improvement of a pipeline IMP. The operator shall instruct personnel to meet its requirements.

4.4.2 Scope of integrity management program

The operator shall determine the scope of the IMP, including identifying the applicable pipeline systems and the goal and objectives of the IMP for the identified pipeline system.

The operator shall maintain a documented IMP that addresses the management of the pipeline integrity and specific treatment for all unacceptable risk.

4.4.3 Organization structure, roles and responsibilities

The operator shall have a clearly defined organizational structure to implement the IMP. Pipeline integrity management shall be carried out by personnel with clearly defined roles, responsibilities, authority and accountability in implementing and reviewing the IMP.

Where applicable, the organizational structure shall identify the linkages to other related management system programs, such as the safety and environmental programs.

The organizational structure should also take into account both upstream and downstream system inputs/outputs to ensure no changes in one system can have a negative effect on an adjacent system not within the operator' control.

4.4.4 Records and documents management plan

The IMP shall be documented and effectively updated. Program items to be documented shall include the following:

— documents and records needed by the operator to ensure the effective operation and control of its processes;

— statements of integrity management policy and objectives;

— procedures required by the implementation of integrity management.

A records and documents management plan shall be developed to facilitate the storing and retrieving of records and documents in a timely manner. The plan shall include means to confirm accuracy and quality of inputs.

4.4.5 Communication plan

A plan for reporting and communication to all stakeholders, including but not limited to employees, management, authorities, customers, public, local officials and responders, shall be established and maintained.

4.4.6 Management of change plan

A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system product being shipped, design, operation or maintenance are documented and evaluated for their potential risk impacts, and to ensure that changes are documented and evaluated.

4.4.7 Management review and audit plan

Management review and audit of the pipeline integrity management program shall be conducted at regular intervals to determine the adequacy, implementation and effectiveness of the integrity program. The focus of management reviews and audits shall be on evaluating:

— effectiveness and adequacy of the IMP to meet its stated goals and targets;

— implementation of the IMP;

— compliance with regulatory and operator’s requirements; and

— identification of corrective actions for continual improvement.

4.4.8 Training and competency plan

The IMP shall establish clear competency requirements for all roles involved in pipeline integrity management, including operators, contractors, engineers, and other persons using this document.

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

5. Integrity management for the pipeline lifecycle phases

5.1 General

5.1.1 Objectives

Pipeline system design (including material procurement and selection) and construction (including installation testing and commissioning) along with operations and maintenance activities have an impact on pipeline integrity.

Although these activities may follow recognized standards, it is important to realize that compliance with a minimum standard might not identify potential long term integrity issues. Therefore, it is important to review pipeline risks at handover from each pipeline phase and throughout the integrity lifecycle.

Designers, procurers, constructors, operators and maintenance personnel and integrity management practitioners shall be aware of the subclause 5.3 that highlight the interrelation between the pipeline lifecycle phases (which entails components such as design, procurement, fabrication, construction, commissioning, operation and maintenance) and integrity. Subclause

5.3 identifies areas where changes in each of the pipeline lifecycle phases may be warranted to aid in long term integrity management.

5.1.2 Principles

The following high level principles shall be considered during each of the pipeline lifecycle phases:

a) Risk-based approaches to integrity management shall be applied. Clause 6 provides guidance on risk assessment methodologies.

b) Functional requirements for integrity management shall be incorporated into each lifecycle phase.

c) The concepts and requirements of IMP shall be regarded as the basis for long term asset management.

d) Any deviations shall be reviewed to evaluate impacts on integrity.

e) Pipeline segments shall be designed according to ISO 13623, or a similar standard, to accommodate ILI tools. Where ILI accommodation is not practical, e.g. short service life, short connections or off-takes, the operator shall identify an appropriate alternative integrity assessment method.

f) Data is regarded as the foundation of a pipeline integrity management and the operator shall have a comprehensive plan for collecting and managing all data sets.

5.2 Key lifecycle integrity processes

Integrity assessment is an ongoing process that utilizes data from the various pipeline lifecycle phases to enable the operator to determine the integrity or soundness of the pipeline for its continued operation or design purpose.

The integrity assessment process for new pipelines utilizes construction inspection data and for operating pipelines utilizes data from pipeline condition monitoring activities, such as ground movement, ILI, DA and pressure test to identify threats. After all the threats are identified, they are evaluated and characterized, in some cases by excavating and in-situ measurements. The potential consequence and likelihood of identified threats are further evaluated using the appropriate method to determine fitness for purpose that includes a notional factor of safety. The operator shall determine the appropriate integrity assessment methods based on the threat and the capabilities and limitations of the integrity assessment method.

An integrity assessment can be conducted to evaluate the risk, and the interval for the next integrity assessment shall be determined based on the findings.

For pipelines already in operation, an integrity assessment shall be completed within 3 years if no previous integrity assessment has been performed.

5.3 Lifecycle phases for integrity management

5.3.1 General

Integrity management occurs throughout the whole lifecycle of an asset from the initial feasibility studies through to abandonment and heavily influences the design considerations and the ongoing maintenance/ management techniques.

All threats to the integrity of the asset shall be identified and controlled throughout the lifecycle; therefore the elimination of the threats by improvements in design can provide a significant advantage to the on-going safe operations.

Each of the lifecycle phases has opportunities to mitigate or control integrity threats and each life cycle shall be adequately designed and controlled to optimize the ongoing risk and expense.

The personnel at each lifecycle phase should be familiar with basic pipeline integrity issues and concepts. In addition, a process shall be developed where the pipeline integrity subject matter experts will review each lifecycle phase to determine if there are potential pipeline integrity issues that need resolution.

5.3.2 Feasibility

5.3.2.1 Objectives

At the feasibility phase of the integrity management lifecycle the key integrity risks are associated with the physical attributes of the route. Proactive avoidance of threats is a critical design objective and action at this phase in the lifecycle can provide significant benefits during construction and reducing the level of necessary mitigation being applied throughout the lifecycle leading to improved reliability and reduced operating cost.

5.3.2.2 Principles

At this phase in pipeline development the basic route selection is often a straight line between supply and delivery points. Modifying the route would typically increase the overall pipeline length, however reduced operation and maintenance costs can warrant the increased construction cost.

Optimized routing can take into account many of the key potential threats by avoiding obvious difficulties during construction. Improved routing to avoid mountainous terrains, permafrost, major rivers, flood plains and swamp zones can provide significant construction improvements. Other considerations at this phase include access to the pipeline for hydro-testing activities and pipeline drying and areas of critical consequences associated with safety of the public or damage to the environment.

Realistic route selection at this phase will improve the cost estimates for the proposal enabling more realistic evaluation of the project costs.

5.3.3 Design

5.3.3.1 Objectives

At the design phase, all of the integrity threats that the pipeline system will be exposed to during its lifetime are anticipated. The operator shall also anticipate future land use activities and encroachment that can lead to elevated consequences and a change in the original risk profile or have a direct impact on pipeline integrity, due to third party damage. In addition, the pipeline should be designed to enable condition monitoring of the pipe wall using applicable inspection technologies such as ILI.

5.3.3.2 Principles

At the design stage, CCAs analysis shall be implemented using the methods stated in 6.6.2. Routing selection shall be optimized to avoid CCAs where practical. Where rerouting is not feasible, mitigation measures (e.g. increasing wall thickness) shall be adopted.

To confirm that suitable physical and procedural protective methods have been implemented, pipeline segments, especially CCAs, shall be validated including consideration of future changes to the environment, e.g. future urban growth, rezoning.

Where special construction methods or processes are utilized, they shall be assessed to determine any impact on future integrity and necessary mitigation that might be required.

5.3.4 Procurement

5.3.4.1 Objectives

At the procurement phase of the integrity management lifecycle, the key integrity risks are associated with meeting the quality and functionality of the materials detailed by the designer. Proactive avoidance of inappropriate or defective material at this phase in the lifecycle can reduce the risks associated with failure during testing and operation.

In the operating phase, poor procurement decisions can lead to substandard equipment reducing functionality or safety and can be significant to the economic performance of the assets.

5.3.4.2 Principles

At this phase in the lifecycle, the quality of the final asset can be directly related to the material supplied. During design, specific materials will have been selected for the required duty and may have been specified to deal with the risk from identified threats. Failure to maintain the quality during procurement could lead to designed mitigation not being installed into the final build allowing threats to remain untreated.

Data management during procurement is essential to allow a full understanding of the source and specification materials involved during the design. Whilst important during construction, these records shall be maintained throughout the life of the asset.

5.3.5 Fabrication

5.3.5.1 Objectives

At the fabrication phase of the integrity management lifecycle, the key integrity risks are associated with poor quality in the fabrication processes and building components to incorrect dimensions.

5.3.5.2 Principles

At this phase in the lifecycle, the quality of the final asset can directly relate to the fabricated items and its dimensional tolerances. Where fabricated items are incorrectly built, this could lead to long term operational and integrity threats.

5.3.6 Transportation and storage

5.3.6.1 Objectives

At the transportation and storage phase of the integrity management lifecycle, the key integrity risks are associated with pipeline components suffering damage and no longer being suitable for construction or fit for purpose.

5.3.6.2 Principles

At this phase in the lifecycle, the quality of the final asset can be directly impacted by the transportation and storage. Care is required during handling and storage techniques shall be suitable for the items being handled to ensure that they do not sustain impact and are correctly stored to protect against environmental damage. Appropriate handling techniques shall be designed and used with correctly designed storage facilities.

Any delays that can impact pipeline integrity during transportation and storage shall be reviewed and their potential impact on the pipeline materials assessed and mitigated.

5.3.7 Integrity during construction

5.3.7.1 Objectives

At the construction phase of the integrity management lifecycle, the key integrity risks are associated with failing to build the asset to the specification laid down by the designer.

5.3.7.2 Principles

At this phase in the lifecycle, the quality control of the works and records management are the key aspects for management activities. Failing to build the asset to the designed standards for valid reasons shall be managed and assessed on a case-by-case basis. Construction re-work and even the repair of major defects developed during construction can significantly increase both the time line and costs for construction.

In all cases management of change will be required to confirm the suitability of any design changes and can require adjustment to the arrangements for ongoing integrity and reliability. Risk assessments shall be carried out to identify any necessary mitigation adjustments to the IMP.

As-built documentation shall reflect the exact details of the build to ensure that integrity issues in future years can be investigated as far as possible without requiring excavation/inspection.

In the event of any change in the route during the construction phase, CCAs shall be re-identified and re-assessed for the design optimization. Relevant information shall be updated from time to time in the event of any change to pipeline segmentation identified during the construction phase.

5.3.8 Pre-commissioning and commissioning

5.3.8.1 Objectives

At the pre-commissioning and commissioning phases of the integrity management lifecycle, the key integrity risks are associated with failing to design appropriate procedures during hydro-test leading to insufficient testing or in an extreme case damage to the pipeline and/or its coating from excessive strain.

5.3.8.2 Principles

The pre-commissioning and commissioning phases require an appropriate checking and proving procedure. Significant damage can be caused to the asset from incorrect testing and the personnel shall be aware and comply with the detailed requirements.

Pressure testing has the potential to impact safety and the environment, therefore a pressure testing plan shall be developed and a risk assessment shall be completed. During testing all pipeline sections will undergo strain to different extents and a testing procedure shall be developed to ensure that lower lying sections of pipe (where hydraulic weight adds to the strain being applied) do not fail. The risk assessment shall examine the potential consequences associated with a pressure test such as worker safety and failures. In addition, contingency plans shall be put into place in the event of a pipeline failure during the pressure testing.

Data records of the testing are critical requirements for ongoing pipeline safety determination, particularly where future changes to operating pressure are being considered and pipeline defects are being assessed.

Following hydro-test the pipeline shall be protected from all threats regardless of whether it has been fully pressurised. Surveillance and lands processes shall commence.

5.3.9 Handover – preparation for operation

5.3.9.1 Objectives

At the handover phase of the integrity management lifecycle, the pipeline systems are implemented to ensure that key integrity threat mitigation is adequate and records are retained.

5.3.9.2 Principles

Operation personnel and integrity management practitioners shall be informed of any mitigation aspects built into the design of the pipeline including the interrelation between any particular aspects built into the operational activities and the resultant integrity control.

The following principles shall be considered:

— All data collected from the design, fabrication, construction, and commissioning phase shall be gathered, maintained and updated throughout the life of the pipeline. The constructor shall provide full design and construction documentation in a format to suit the operator.

— Construction design requirements to ensure pipeline integrity shall be incorporated into the pipeline operating procedures and maintained as well.

— At this phase the operator shall review all records for completeness and consider the records management systems to ensure that necessary records are preserved for the life of the asset. Storage methods shall utilise electronic systems where possible, considering the impact of future changes to computer operating systems and programs considered.

— All inspection data (visual, NDT and ILI) obtained during the construction and testing phases shall be evaluated in a baseline assessment. Imperfections that are acceptable based on relevant construction specifications and standards, shall be evaluated to determine their suitability for long term operations. The baseline assessment data is one of the inputs used in the IMP once the pipeline system placed into operation.

— Designed threat mitigation shall be reviewed to ensure that the pipeline risks have been adequately considered and all necessary threat mitigation implemented. Assumptions regarding pipeline segments within the critical consequence areas shall be validated and confirmed prior to the commissioning stage. If changes or variances are identified, the risk assessment and treatment of the CCA shall be updated and this may include commissioning plans that consider CCAs and safety during the commissioning phase.

— The operator shall review/determine the planned maintenance requirements for the new pipeline assets and schedule the maintenance into a maintenance system.

— Where GIS is being used, the data shall be uploaded within a suitable timeframe to enable integrity management practices to commence.

5.3.10 Operation and maintenance

5.3.10.1 Objectives

Pipeline system operation and maintenance activities can directly impact pipeline integrity. Thus, all activities executed on or in the vicinity of a pipeline, either by third party companies or the operator itself, shall be adequately designed and controlled throughout the operational phase to ensure that integrity isn't compromised.

Integrity management during operation shall primarily be pro-active. The operator shall put in place an adequate organization to gather all relevant changes from the original data used for the first integrity assessment. Potential issues shall be identified to enable consideration of any necessary mitigation activities for every risk and threat during the operational period.

5.3.10.2 Principles

The following principles shall be considered for pipeline operation and maintenance:

— The operator shall be adequately resourced to monitor operational conditions to detect and assess any relevant changes impacting integrity in an ongoing process.

— Relevant changes in operation (pressure cycles, etc.) shall be assessed to identify any specific integrity threats.

— The impact of any deviation from operating procedures shall be recorded and assessed to identify any immediate or long term implications for the pipeline integrity.

— The operator shall collect sufficient data to perform threat analysis, consequence analysis and risk assessments. Implementation of the IMP will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats.

— Any threats to integrity and issues identified during operation shall be recorded and used to consider whether additional mitigation activities are required.

— Any change to the operating environment of the pipeline including land use shall be assessed and mitigated as necessary.

— Any incident during the operational period shall be recorded and mitigation against further instances shall be considered and implemented as necessary.

— The performance/efficiency of the IMP shall be reviewed periodically using key performance indicators (KPIs).

5.3.11 Modifications during operation

5.3.11.1 Objectives

During operation, pipelines may be modified for various reasons, such as lowering the pipe to accommodate roads, raising the pipe to allow for drainage works, adding of branches, etc. These modifications may employ different processes and designs from the original design. For example, the modifications can use different material grades and thickness, construction and joining techniques, coating, etc. These modification projects shall be managed, relevant to integrity, similar to a new construction.

5.3.11.2 Principles

Modified pipelines shall be designed appropriately utilizing similar processes to a new pipeline to ensure that any adverse change to threat levels are eliminated or avoided where possible. New or changed threats and/or consequences shall be documented and mitigated.

Pipeline as-built drawings and abandonment details shall be stored and maintained in association with the original records and all existing drawings and drawing systems updated as necessary.

5.3.12 Abandonment

5.3.12.1 Objectives

When pipe is abandoned in place and not removed, the abandoned sections shall be appropriately decommissioned, such that they are left in a condition that is safe for the public and the environment.

5.3.12.2 Principles

When pipe is abandoned in place and not removed, the following shall be considered:

— internal grouting, such as sand slurry;

— sectioning with concrete (or similar) to avoid water tunnelling along the asset;

— assessing the surface impact of a pipe wall collapse;

— positive isolation and disconnect from existing operating assets;

— retaining CP on the asset.

6. Risk assessment

6.1 Definition of objectives and requirements

6.1.1 General

Risk assessment shall be applied throughout the entire pipeline lifecycle to identify and quantify risk to enable identification and prioritization of mitigation activities. There are several approaches to pipeline risk assessment that range from qualitative to quantitative risk approach. The operator can choose any model that supports its objectives and meets regulatory requirements, while still meeting a minimum level of technical justification. The approach should be selected according to data sufficiency and objectives of the assessment. Annex A shows an example of semi-quantitative approach.

The outcome of the risk assessment should be presented on a risk matrix in terms of likelihood and consequence, the categories for which shall be defined in quantitative terms where possible. An example of a risk matrix is shown in Annex B.

In case the pipeline system information is insufficient or very limited, conservative assumptions on the system conditions shall be taken into account.

6.1.2 Objective

The objectives of risk assessment for an IMP shall include:

a) identification of the threats to pipeline integrity;

b) determination of the probability (likelihood) of failure (PoF) for each plausible threat;

c) determination of the consequence of failure (CoF) for each plausible threat;

d) determination of the risk represented by PoF and CoF;

e) prioritization of segments of a pipeline system in the order of risk level (risk register);

f) risk reduction through mitigation (see Clause 9).

A typical risk assessment process follows the flowchart in Figure 3.

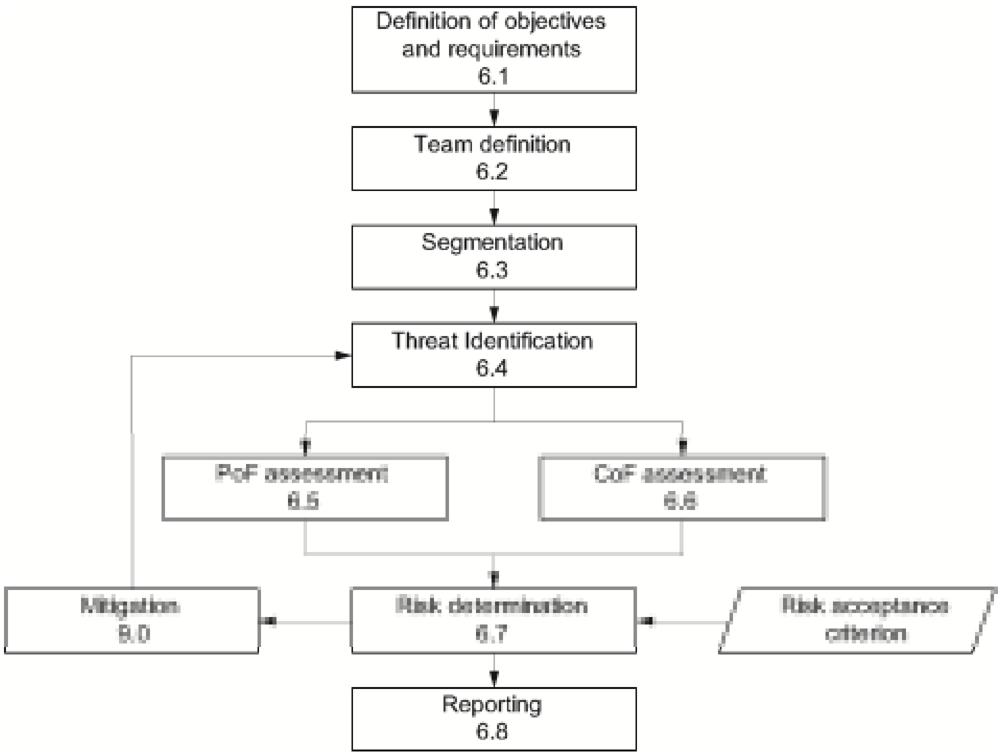


Figure 3 — Risk assessment process

6.1.3 Requirements

The risk assessment approach shall conform to ISO 31000 and IEC 31010 with the following essential requirements:

a) Assessment parameters – The risk assessment shall define 'failure' and produce verifiable estimates of failure potential. The probability of failure is the likelihood of the full failure potential occurring, not just that of an event occurring. Therefore, the risk assessment produces related measures of probability of failure and potential consequence.

b) Measure in verifiable units – Probability of failure and probability of consequence shall be expressed in clear verifiable units, e.g. '1 in 20 years' and 'costs/km-year'.

c) Integrate pipeline knowledge – All plausible failure modes and mechanisms shall be included in the assessment of probability of failure. The risk assessment shall integrate all available risk knowledge from each of the lifecycle phases, but especially lessons learned from operation and maintenance and any issues discussed and/or resolved under management of change.

d) Quantify data uncertainty – It is important to know the level of certainty of all input parameters. It is acceptable to use data with high uncertainty; however the risk assessment methodology shall propagate this uncertainty and show its effect on the final risk results. Black-box models should be avoided where possible to ensure a good understanding of the mechanism behind the results.

e) Fully characterize consequences of failure – The risk assessment shall identify and acknowledge the full range of plausible failure scenarios. The consequences of all scenarios, no matter how unlikely, shall be quantified. Any interaction or overlap of threats shall be taken into account.

f) Produce risk profiles – The risk assessment shall produce a continuous profile of risk levels along the pipeline. The risk assessment may segment the pipeline where risks are essentially the same to provide a simplified review of the pipeline profiles.

g) Control the bias – The risk assessment shall generate transparent (e.g. verifiable) results. The assessment shall be free of inappropriate bias that might lead to incorrect conclusions.

h) Appropriate aggregation – Summarization of the risks presented by multiple segments can be desirable. Where this is utilized, such summaries shall avoid simple statistics (e.g. averages, maximums) or weighted statistics that can mask the real risks presented by the segments.

6.2 Team definition

Risk assessments shall be carried out by a group that includes competent and experienced representatives of those responsible for operating, maintaining and managing the pipeline system. They shall have adequate knowledge of the system to be able to determine accurate PoF and CoF, and to be able to define practicable mitigation measures. It is important to involve those who will be responsible for the various disciplines during operations, or the relevant technical authorities, in the design risk assessment cycle, to ensure that they agree with the assessment of risk, and the practicality and effectiveness of proposed operational mitigations.

6.3 Segmentation

The segmentation of a pipeline allows for clear understanding of the presence of threats in order to identify the likely damage processes and to establish the most likely consequence scenarios.

The pipeline system shall be divided into segments based on pipeline characteristics and the characteristics of the area through which the pipeline passes. The choice of segments shall be such that PoF and CoF can be considered to be uniform within each segment.

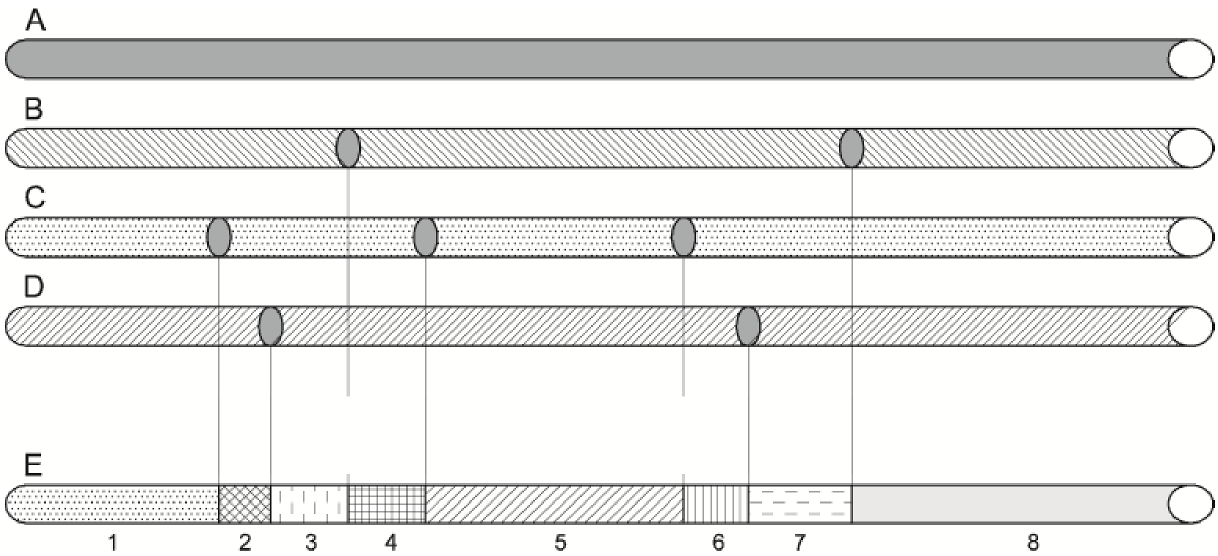
Along the length of each segment, the following items shall be uniform, such as:

a) pipeline properties, e.g. diameter, wall thickness, coating type;

b) threats;

c) most likely consequence scenario, e.g., population density and environmentally sensitive areas.

An example of segmentation for a pipeline system is shown in Figure 4.



Key

A Diameter

B Wall thickness

C Coating type

D Population

E Pipeline segment

Figure 4 — Example of pipeline segmentation

6.4 Threat identification

Threats to the integrity of the pipeline shall be regularly identified throughout the service life of the pipeline. In addition, threats shall be determined based on an analysis performed at each lifecycle phase. Identification of potential or known threats for each lifecycle phase can be based on data obtained through a pipeline lifecycle quality assurance process, that utilizes quality control data such as design and data reviews and inspections conducted throughout the lifecycle. In addition, potential or known threats can be identified based on an analysis of industry-wide pipeline failure history and operation of similar pipeline systems. Processes such as hazard identification study (HAZID) and failure tree analysis (FTA) may also be used as an input to the threat identification.

The following list illustrates typical pipeline lifecycle phases:

a) feasibility;

b) design;

c) procurement;

d) fabrication;

e) transportation and storage;

f) construction;

g) pre-commissioning and commissioning;

h) handover;

i) operation and maintenance;

j) modifications;

k) decommissioning/suspension/abandonment.

Table C.1 provides an example of threat categorization and associated causes of occurrence during each phase of the pipeline lifecycle.

6.5 Probability of failure assessment

The PoF shall be estimated for all plausible threats identified for each segment. If more than one failure mode is plausible for a given threat, the PoF shall be estimated for each failure mode.

The PoF may be estimated using industry-wide or company failure statistics, or by probabilistic analysis. The effects of existing mitigation measures shall be taken into account in the estimation of PoF.

Where historical data are used for frequency analysis or for validation of frequency analysis conducted by other methods, the suitability of the data and its compatibility with the characteristics of the pipeline system being analysed shall be considered.

In assessing the threat, the mechanism of the threat shall be considered. For example, the threat “corrosion” can result from localized pitting or to a uniform metal loss over a large area. Both will lead to different failure modes.

Interaction of threats and of the associated damage mechanisms shall be considered and taken into account in the PoF assessment.

The PoF may be expressed qualitatively or quantitatively. It may be expressed quantitatively on a collective basis (e.g. failures per year) or on a linear basis (e.g. failures per kilometre-year).

6.6 Consequence of failure assessment

6.6.1 Consequence assessment

The consequence of failure can be expressed in categories such as:

a) impact on people (population density type of buildings, encroachment, etc.);

b) impact on the environment (water bodies, environmentally sensitive area, etc.);

c) impact on business (deferred production, reputation, societal effects, impact on operations, repair, etc.).

The consequence assessment for each category shall be carried out by a competent specialist in that area. The consequence of failure shall be determined for each failure mode for each segment.

Estimation of the impact of the loss of containment shall take into account the following:

a) nature of containment, e.g. gas or liquid, ignition, flammability, toxicity, reactivity, dispersion mode, etc.;

b) pipeline properties, such as pipeline diameter, wall thickness, type of coating, pressure, etc.;

c) pipeline topography and elevation profile;

d) population density (potential impact radius) and environmentally sensitive areas, such as water bodies, etc.;

e) failure mode, such as leak or rupture;

f) presence of mitigating measures to restrict loss of containment, such as leak detection, use of remote operated isolation valves and emergency response plan ;

g) possible accident scenarios following a loss of containment, which can include:

   1) pressure waves following fluid release;

   2) combustion/explosion following ignition;

   3) toxic effects or asphyxiations.

NOTE 1 Knowledge of the release mechanism and the subsequent behaviour of the released material enables qualitative or quantitative estimates to be made of the effects of the release at any distance from the source for the duration of exposure.

NOTE 2 Appropriate methods of consequence analysis vary widely in extent and degree of detail, depending on the type of threat to be analysed and the objectives of the assessment.

6.6.2 Critical consequence areas analysis

6.6.2.1 Critical consequence areas for liquid pipelines

Critical consequence areas for liquid and gas pipelines can be categorized as Table 1.

Table 1 — CCAs-affected segments ranking

Pipeline medium	Item	Ranking
Liquid pipeline	A class 5 location [a].	Rank [illegible]
	A class 4 location [a].	Rank [illegible]
	A class 3 location [a].	Rank [illegible]
	A populated area means a place that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area as according to local regulation and company policy.	Rank [illegible]
	An unusually sensitive area such as an area of drinking water resource or ecological resource as according to local regulation and company policy.	Rank [illegible]
	Environment sensitive area listed in 6.6.2.3.3 or according to local regulation and company policy.	Rank [illegible]

Gas pipeline	A class 5 location [a].	Rank ⍰
	A class 4 location [a].	Rank ⍰
	A class 3 location [a].	Rank ⍰
	Any area that contains a high traffic road crossing with the pipeline as according to local regulation and company policy.	Rank ⍰
	Any area in a class 2 location where the potential impact radius is greater than 200 m, and the area within a potential impact circle contains 20 or more persons; or any area in a class 2 location where the pipeline is within 300 m contains 20 or more persons or as according to local regulation and company policy.	Rank ⍰
	Any area in a class 2 location where the potential impact circle contains an identified site; or any area in a class 2 location where the pipeline is within 90 m, 200 m or 300 m contains an identified site or as according to local regulation and company policy. [b]	Rank ⍰

[a] Class location is in accordance with ISO 13623.

[b] For a pipeline not more than 305 mm in nominal diameter and operating at a MAOP of not more than 8,3 MPa, an area which extends 90 m from the centerline of the pipeline to the identified site. For a pipeline greater than 762 mm in nominal diameter and operating at a MAOP greater than 6,89 MPa, an area which extends 300 m from the centerline of the pipeline to the identified site. For a pipeline not described in above, an area which extends 200 m from the centerline of the pipeline to the identified site.

All CCAs can be divided into three classes (see Table 1), such that class I represents less serious while class III represents most serious.

6.6.2.2 Definitions

6.6.2.2.1 Identified sites

Identified site means each of the following areas:

a) An outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12 months period. (The days need not be consecutive.) Examples include but are not limited to beaches, playgrounds, recreational facilities, camping grounds, outdoor theatres, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility.

b) A building that is occupied by 20 or more persons during at least 5 days a week for 10 weeks in any 12 months period. (The days and weeks need not be consecutive.) Examples include but are not limited to religious facilities, office buildings, community centres, general stores, or roller skating rinks.

c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

6.6.2.2.2 Potential impact radius

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR (for natural gas pipeline) is determined by the Formula 1.

$$r = 0{,}0998\sqrt{d^2 p} \qquad (1)$$

where

d is the pipeline outside diameter, expressed in millimetres (mm);

p is the operating pressure, expressed in mega pascal (MPa);

r is the radius of impact, expressed in meters (m).

0,0998 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. Other gases or rich natural gas shall use different factors.

The length of the critical consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy (see Annex D).

In a performance-based program, the operator may consider alternate models that calculate impact areas and consider additional factors, such as depth of burial, which can reduce impact areas.

6.6.2.2.3 Environmentally sensitive area

An environmentally sensitive area means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a liquid hydrocarbons pipeline release. The IMP shall define environmentally sensitive areas for drinking water resources and ecological resources.

An environmentally sensitive area drinking water resource is defined in accordance with local laws, regulations and experience. The following list provides examples:

a) the water intake for a community water system (CWS) or a non-transient non-community water system (NTNCWS) that obtains its water supply primarily from a surface water source and does not have an adequate alternative drinking water source;

b) the source water protection area for a CWS or an NTNCWS that obtains its water supply from an aquifer and does not have an adequate alternative drinking water source;

c) the sole source aquifer recharges area where the sole source aquifer is a karst aquifer in nature.

An environmentally sensitive area ecological resource is defined in accordance with local laws, regulations and experience. The following list provides examples:

a) an area containing endangered species or ecological community;

b) a multi-species assemblage area;

c) a migratory water bird concentration area.

6.7 Risk determination

For risk assessment, the methodologies listed in IEC 31010 can be used. The probability and consequence shall be matched to the same failure mode. For example, if the consequence level is assigned on the basis of a leak, then the probability should be that of a leak, not merely the probability of the threat (e.g. corrosion) occurring. For quantitative method, risk can be described by Formula 2 and 3.

a) For a single failure mode:

$$Risk_i = p_i \times C_i \tag{2}$$

b) For multiple failure modes 1 to *n*

$$Risk = \sum_{1}^{n} p_i \times C_i \tag{3}$$

where

C is the CoF;

p is the PoF;

1 to *n* is threat category.

For semi-quantitative method, the likelihood and consequence for each threat should be plotted on the risk matrix to determine their significance. The matrix should be divided into bands representing increasing levels of overall risk as illustrated in Annex B.

Quantitative risk assessments may be carried out using deterministic and probabilistic approaches.

6.8 Reporting

The risk assessment process shall be documented in a risk assessment report.

The report shall clearly portray the pipeline risk profile at a specified time, or as a function of time. In such reports, estimated risk should be expressed in terms appropriate for the stated objectives and audience, the strength and limitation of different risk measures used should be explained, and the uncertainties surrounding estimated risk should be set out in straightforward language.

The extent of the risk assessment report depends upon the objectives and scope of the assessment; however, the documentation shall include as a minimum the following:

a) objectives and scope;

b) pipeline system description;

c) risk assessment methodology;

d) limitations and assumptions;

e) threat identification results;

f) PoF analysis results, including assumptions;

g) CoF analysis results, including assumptions;

h) risk evaluation results;

i) sensitivity and uncertainty analysis;

j) discussion of results (including a discussion of analysis problems);

k) conclusions and recommendations;

l) references, including all sources necessary to support any models or analytical techniques applied; and

m) names and qualifications of personnel who participated in the analysis.

6.9 Reassessment

The risk reassessment shall be carried out a regular basis or at a specific date set by the risk assessment group.

Additionally, a risk reassessment shall be carried out in response to:

a) changes in design or operation of the system;

b) changes of the pipeline environment;

c) unexpected results of mitigation measures, e.g. measure is not effective; and

d) acquisition of new information about the system (e.g. the results of an inline inspection run).

A risk reassessment might be carried out in response to incidents that occur on the pipeline system or relevant incidents or on systems of similar nature.

7. Inspection and monitoring

7.1 In-line inspection

7.1.1 General

ILI is an important method in the investigation of the condition of a pipeline. The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives (see Table 2). ILI planning, tool selection, capabilities, and qualification of personnel shall be in accordance with regulatory requirement. If no regulator requirement is available, the following standards can be used as references:

— API Std 1163;

— ASNT ILI-PQ;

— NACE SP0102;

— NACE 35100.

7.1.2 Baseline inspection

The baseline inspection represents the earliest condition of the system to identify any integrity related issues introduced during the construction phase and as reference for comparison with future inspection activities. It is considered a common practice and a good project approach to let the external baseline coincide with the as-built survey. As-built also takes into consideration all the intervention works performed before, during and after the pipeline installation.

Consideration shall be taken to execute the internal baseline inspection before handover of the pipeline system to operation, to ensure the design, manufacturing and construction of the pipeline are compatible with the design basis.

For a new pipeline segment, baseline inspection should be conducted within 3 years after commissioning or as required by local regulatory practice.

ILI tools can be selected from Table 2 based on the anomalies expected and used to obtain the initial condition of the pipeline.

7.1.3 Considerations for the use of ILI tools

7.1.3.1 Choice of ILI tools

The choice of ILI tool depends on the specifics of the pipeline section, previously identified risks and the goal set for the inspection. The operator shall outline the process used in the IMP for the selection and implementation of the ILI inspections. Table 2 provides a guide to the ILI methods available.

The operator shall assess and demonstrate the reliability of the chosen ILI method by examining the following:

a) ability to detect the presence of multiple cause anomalies;

b) confidence level of the ILI method and service provider specification (e.g. probability of detecting, classifying, and sizing the anomalies);

c) performance history of the ILI method/tool and service provider;

d) success rate/failed surveys and service provider;

e) ability of detection and classification, sizing accuracy and location accuracy of the tool;

f) validation of specifications by either pull through testing or correlation excavations or other equivalent methods.

Table 2 — Types of ILI tools and inspection purposes

Anomaly	Imperfection /defect /feature	Metals loss detection tools				Crack detection tools		Deformation detection tools
		Magnetic flux leakage（MFL）			Ultrasonic compression [m]	Ultrasonic shear wave [m]	EMAT	
		Standard resolution（SR）	High resolution （HR）	Transverse MFL				
Metal loss	External corrosion	Detection [a] sizing [b] No ID/OD discrimination	Detection [a] sizing [b]	Detection [a] sizing [b]	Detection [a] sizing [b]	Detection [a] sizing [b]	Limited detection	No detection
	Internal corrosion							
	Scratches							
Crack-like anomaly	Narrow axial external corrosion	Detection [a]	Detection [a]	Detection [a] sizing [b]	Detection [a] sizing [b]	Detection [a] sizing [b]	Limited detection	No detection
	Stress corrosion cracking	No detection	No detection	Limited detection [a, c] sizing [b]	No detection	Detection [a] sizing [b]	Detection [a] sizing [b]	No detection
	Fatigue cracks	No detection	No detection	Limited detection [a, c] sizing [b]	No detection	Detection [a] sizing [b]	Detection [a] sizing [b]	No detection
	Long seam cracks, etc. (toe cracks, hook cracks, incomplete fusion, preferential seam corrosion)	No detection	No detection	Detection [a, c] sizing [b]	No detection	Detection [a] sizing [b]	Detection [a] sizing [b]	No detection
	Circumferential cracks	No detection	Detection [c] sizing [b]	No detection	No detection	Detection [a] sizing [b, d]	Detection [a] sizing [b, d]	No detection
	Hydrogen-induced cracks (HIC)	No detection	No detection	No detection	Detection [a]	Limited detection	Detection [a] sizing [b]	No detection
Deformation	Sharp dents	Detection [e, g]	Detection [e, l]	Detection [e, g]	Detection [e, g]	Detection [e, g]	No detection	Detection [f] sizing
	Smooth dents	Detection [e, g]	Detection [e, l]	Detection [e, g]	Detection [e, g]	Detection [e, g]	No detection	Detection [f] sizing

	Buckles	Detection [e, g]	Detection [e, l]	Detection [e, g]	Detection [e, g]	Detection [e, g]	No detection	Detection [f] sizing
	Wrinkles, ripples	Detection [e, g]	Detection [e, l]	Detection [e, g]	Detection [e, g]	Detection [e, g]	No detection	Detection [f] sizing
	Ovalities	No detection	No detection	No detection	No detection	No detection	No detection	Detection sizing [b]
Misc. components	In-line valves and fittings	Detection	Detection	Detection	Detection	Detection	Detection	Detection
	Casings (concentric)	Detection	Detection	Detection	No detection	No detection	No detection	No detection
	Casings (eccentric)	Detection	Detection	Detection	No detection	No detection	No detection	No detection
	bends	Detection	Detection	Detection	Limited detection	Limited detection	Limited detection	Detection [h] sizing [h]
	Branch appurtenances /hot taps	Detection	Detection	Detection	Detection	Detection	Detection	No detection
	Close metal objects	Detection	Detection	Detection	No detection	No detection	No detection	No detection
	Thermite welds	No detection	No detection	No detection	No detection	No detection	No detection	No detection
	Pipeline coordinates	No detection	Detection [k]	Detection [k]	Detection [k]	Detection [k]	No detection	Detection [k]
Previous repairs	Type A repair sleeve	Detection	Detection	Detection	No detection	No detection	No detection	No detection
	Composite sleeve	Detection [i]	Detection [i]	Detection [i]	No detection	No detection	No detection	No detection
	Type B repair sleeve	Detection	Detection	Detection	Detection	Detection	Detection	No detection
	Patches/half soles	Detection	Detection	Detection	Detection	Detection	Detection	No detection
	Puddle welds	Limited detection	Limited detection	Limited detection	No detection	No detection	No detection	No detection
Misc. damage	Laminations	Limited detection	Limited detection	Limited detection	Detection sizing [b]	Limited detection	No detection	No detection
	Inclusions (lack of fusion)	Limited detection	Limited detection	Limited detection	Detection sizing [b]	Limited detection	No detection	No detection

	Cold work	No detection	No detection	No detection	No detection	No detection	No detection	No detection
	Hard spots	No detection	Detection [j]	No detection	No detection	No detection	No detection	No detection
	Grind marks	Limited detection [a]	Limited detection [a]	Limited detection [a, b]	Detection [a, b]	Detection [a, b]	No detection	No detection
	Strain	No detection	No detection	No detection	No detection	No detection	No detection	Detection [j]
	Girth weld anomaly (voids, etc.)	Limited detection	Detection	No detection	Detection	Detection [d]	Detection [d]	No detection
	Scabs /slivers/blisters	Limited detection [a]	Limited detection	Limited detection [a]	Detection [a, b]	Detection [a, b]	Detection [a, b]	Limited detection

NOTE From NACE SP0102:2010.

a Limited by the detectable depth, length, and width of the indication.

b Defined by the sizing accuracy of the tool.

c Reduced probability of detection (POD) for tight cracks.

d Transducers to be rotated 90°.

e Reduced probability of detection (POD) depending upon size and shape.

f Also circumferential position, if tool is equipped.

g Sizing not reliable.

h If tool is equipped for bend measurement.

i Composite sleeve without markers is not detectable.

j If tool is equipped, dependent on parameters.

k If tool is equipped with mapping capabilities.

l Sizing is tool dependent.

m ILI technologies that can be used only in liquid environments, e.g. liquids pipelines or in gas pipelines with a liquid couplant.

7.1.3.2 Personnel

The operator shall have the adequate number of qualified staffs to support the ILI run. The operator shall ensure the ILI vendor has an adequate number of qualified staffs who are to complete a valid ILI run.

7.1.3.3 Pipeline preparation

The operator shall be responsible for any pipeline modifications to facilitate cleaning, gauging, and ILI of the system. The launcher/receiver facilities and any other modifications can be either temporary or a permanent installation. Any restrictions identified in the ILI planning stage shall be rectified or confirmed with the vendor as not posing a risk to the inspection tool. Particular attention shall be paid to potential issues such as bend radii for ILI tool passage and the type of valves existing on the pipeline system. In addition, all valves that could be used are serviced and confirmed to be fully functioning.

7.1.3.4 ILI risk management

Prior to project commencement, an ILI implementation plan shall be developed and ILI risk management control measures shall be prepared to eliminate or reduce risks such as ILI and cleaning tools being stuck, stopped or damaging the pipe.

Historical data should be evaluated for anticipated contaminant deposits such as scale, dust, paraffin, etc. to reduce the risk of the ILI tool becoming stuck. The results of current maintenance pigging activities in the pipeline aid in the cleaning program design.

The pipeline shall be cleaned prior to operation of an ILI tools to ensure the data quality of ILI and reduce the risk of failure or degradation of ILI data.

7.1.4 Acceptance of inspection data

Acceptance of inspection data shall be based on two primary principles: data completeness and data quality; which describe the nature and quality of the collected data as expected for use in integrity management processes.

NOTE 1 Data completeness refers to the data collected versus expected for the inspection run. It is a function of pipeline length, diameter, and the number and types of sensors. Data completeness is impacted by: sensor loss, damage, debris and other factors and is assessed for the intended segment of pipeline to be inspected.

NOTE 2 Data quality refers to the quality of the data collected. Data quality is impacted by noise sources to the sensors (mechanical ride, electrical signal noise), product debris, poor coupling characteristics or speed.

7.1.5 Reporting requirements

7.1.5.1 General

The operator and ILI vendor shall reach an agreement on the requirements and specifications of the inspection report in advance. If a number of technologies (e.g. magnetic flux leakage and ultrasonic testing tools) are adopted for the inspection project or multiple functions are integrated in an inspection tool (e.g. integrated detection tools of magnetic flux leakage and mapping), the pipeline information obtained by inspection tools of different types should be integrated in the same report which includes the different anomalies (defects).

Overall requirements for ILI reporting are listed as follows:

a) The report format, including all reporting titles, list of characteristics and data specification, shall be specified. All characteristics and weld numbers specified in the contract and integrated reports shall be conforming to the agreed format.

b) For lists of anomalies of girth welds and spiral welds, referenced upstream and downstream marker points and distance of anomalies shall be given. In addition, the pipe wall thickness shall be provided where anomalies in girth welds and spiral welds.

c) The ILI data software version shall be provided and clearly defined. Any updated software version shall be compatible with previous ones. The final inspection report, pipeline list and data interpretation software report shall conform to the agreed format.

7.1.5.2 Delivery requirements

7.1.5.2.1 Field report

After completion of the ILI field inspection, within agreed time frame, the inspection service provider shall provide an initial report notifying the operator if the inspection is successful. The field report shall include, but is not limit to:

a) data sampling frequency or interval;

b) inspection threshold;

c) report threshold; if report threshold is unspecified features of POD = 90 % shall be adopted;

d) speed curve, pressure curve and temperature curve of inspection tool operation;

e) count of damaged sensors; and

f) statistics of return loss if an ultrasonic testing tool is run.

7.1.5.2.2 Preliminary report

After completion of field inspection, the inspection service provider shall submit a preliminary report within the agreed to timeframe. The initial report shall cover all items agreed to in the contract., for example, features of metal loss with peak depth exceeding 70 % of pipe thickness; features of metal loss in the five most serious places.

If estimated correction factor data relating to features of metal loss have been obtained in preparation of the preliminary assessment report, information about features of metal loss of which estimated repair factor exceeds 1,3 shall be provided.

7.1.5.2.3 Final report

After completion of the field inspection, the ILI vendor shall submit a final report within the agreed to timeframe.

The final report typically includes the following:

a) overview of inspection project, including pipeline defects;

b) performance index of inspection technology;

c) inspection time;

d) operating data of inspection tools;

e) pipeline list;

f) list of anomalies;

g) statistics and summary;

h) defect assessment method;

i) excavation list for serious defects; and

j) corresponding relation between ground reference points and relatively permanent pipeline mark (e.g. mileage pile).

7.1.5.2.4 Supplement report for other type of anomalies

If there are additional requirements, which were agreed to in the contract, the inspection service provider shall additional supplement analysis reports on other features, such as spiral welds anomalies and girth weld anomalies within agreed time frame.

7.1.5.2.5 Software

Software capabilities shall include but not be limited to the following functions:

a) signal data review;

b) presenting absolute and relative distance of characteristics;

c) presenting clock orientation of characteristics;

d) measuring axial and girth distance between any two points in a pipeline;

e) generating clock orientation of interaction between spiral welds/longitudinal welds and girth welds; and

f) generating an excavation list.

7.1.6 Excavation verification

Excavations are required to verify whether the ILI results conform to the stated ILI specifications outlined in the contract. The operator and ILI vendor shall work together to confirm anomalies as per the inspection report, and conduct field excavation. Field validation of defects shall be performed to an inspection protocol agreed to by both parties.

The ILI service provider may, based on field inspection results, continue to improve efficiency and precision of data analysis utilizing the on-site inspection results. If the inspection report does not correlate with the excavation verification, the operator shall require the ILI provider to re-analyse the inspection data. If the data cannot be validated, the inspection tool shall be re-run.

7.2 Aboveground inspection

Aboveground inspection is intended to identify coating defect location and estimate corrosion activity of the pipeline.

The pipeline location and buried depth can be detected from GPS pipeline coordinates and pipeline depth detection equipment.

Aboveground location measurements should be referenced to precise geographical locations and documented so that inspection results can be compared and used to identify excavation locations.

The techniques and measuring equipment for aboveground coating inspection are well established as for close interval potential survey (CIPS), direct current voltage gradient (DCVG) methods, and alternating current voltage gradient (ACVG).

Aboveground survey techniques for the evaluation of underground pipeline coating condition can be found in Annex D of ISO 15589-1:2015, NACE TM0109 or NACE SP0502.

7.3 Non-destructive testing (NDT)

The pipeline indications identified should be inspected by the appropriate NDT method including visual testing (VT), mechanical measure, magnetic particle testing (MT), penetration testing (PT), eddy current testing (ET), X-ray radiography (RT), ultrasonic testing (UT), etc.

MT is mainly used to detect the location, size and shape of surface and near surface indications.

PT is mainly used to detect the position, size and shape of surface opening indications.

ET is mainly used to detect surface and near surface indications.

RT and UT are mainly used to detect internal indications. RT can determine the location, size and shape of the indication. UT usually can determine the location and size of the defect.

Cross validation can be performed using a variety of methods, and should be considered based on the complexity and severity of the indication being evaluated.

In addition to non-destructive testing, for indications that are assessed to be defects which require removal for mitigation, the removed sections should be used to validate the NDT.

7.4 River crossing inspections

7.4.1 Inspecting submerged river crossings

A list of submerged river crossings that require inspection shall be maintained with the appropriate inspection frequency. Rivers that exhibit the following characteristics should be considered for the list:

- flooding that impacts the pipeline;
- bank stabilization issues;
- current shallow cover;
- land movement.

Underwater crossings shall be inspected periodically for adequacy of cover, accumulation of debris, and other conditions that can affect the safety or integrity of the crossing. Under-river crossing segments should be periodically inspected to ensure enough buried depth for integrity of pipelines at river bottom. Due consideration should be made for previous inspection data when establishing the appropriate river crossing inspection frequency. Alternate inspection methods, e.g. sonar, fathometer, should be approved.

7.4.2 Inspecting structurally supported river crossings

A list of structurally supported river crossings and the appropriate inspection frequency for the structure shall be maintained. The following should be considered for the list as minimum:

- structure for corrosion, damage, and misalignment;
- soil-to-air interface;

— anchor bolts for corrosion, coating condition, soundness, and fastener tightness;

— rollers, brackets, and clamps;

— wire rope cables for tension, corrosion, broken strands, and signs of wear at stress points.

7.5 Monitoring

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

7.5.2 Pipeline managers shall monitor CP system regularly to measure the presence of stray current interference.

7.5.3 Effectiveness of internal corrosion-control system shall also be monitored. Consideration of techniques to monitor the effectiveness of an internal corrosion-control program should include, but not be limited to:

a) chemical composition(e.g. CO_2, H_2S,water);

b) monitoring the ongoing operating conditions;

c) deployment of corrosion-monitoring devices, such as weight-loss coupons, corrosion probes, hydrogen probes, and removable spool pieces;

d) NDT, such as ultrasonic or eddy current wall thickness measurement;

e) visual inspection of the internal surface of cut-outs; and

f) internal electronic inspection equipment.

7.5.4 The operator should monitor the pipeline stress changing, displacement or soil movement (e.g. inspections using in-line geometry tools, survey techniques, and slope inclinometers) for pipeline sections that suffered from landslides, floods, geological subsidence, etc. Observations from real-time monitoring system can alarm protection and provide reference to risk evaluation.

7.5.5 Real time monitoring systems to detect leaks or theft and third party interference shall be considered for IMP activities.

8. Integrity assessment

8.1 General

Integrity assessment methods include fitness for purpose assessments to assess the suitability of the pipe for service. Assessment can be carried out on anomaly data obtained through indirect inspection, e.g. ILI data, pressure testing or from the direct measurement of a defects dimensions during direct assessment.

The process evaluates whether:

a) there is sufficient structural integrity to withstand all forces to which it can be subjected to during current and future service; and

b) the pipeline is able to operate within prescribed safety margins.

8.2 Fitness for purpose

8.2.1 Assessment data collection

Collected data required for integrity assessment shall include: pipeline properties, defect parameters, mechanical performance, load parameters, construction data, operating data, historical data, etc.

8.2.2 Defect data statistics and causation analysis

Analysis shall be conducted on defect data from various inspections to identify the probable cause of any detects including the defect type, location on the pipe, distribution along the length of the pipe, coating type and external influences, such as topography, soil type, elevation profile and other relevant attributes identified from the inspection or evaluation results. Such analysis should include but is not limited to:

a) statistical analysis on overall defects;

b) statistical analysis on specific defects;

c) distribution statistics and causation analysis; and

d) statistical analysis of changes between two or more time periods.

The output from causation analysis shall be considered in the risk assessment.

8.2.3 Assessment method selection

The defect assessment methods shall be selected taking into consideration the following variables: defect type and characteristics, load type, service fluid type, pipe material properties, limitations and confidence level of the methodology.

Commonly used assessment methods for the various types of defects are given in Table 3. There can be other proprietary methods not listed in Table 3 and it is not the intent of this document to prevent the use of other methods. However, before using other methods the operator shall verify the suitability and accuracy of the chosen method for each specific defect type assessment.

Table 3 — Assessment standards for defect types

Types of defects	Assessment standards
Corrosion (internal, external)	ASME B31G API RP 579-1 BS 7910 DNV-RP-F101
Gouges	API RP 579-1 BS 7910
Manufacturing defects	API RP 579-1 BS 7910
Dents	API 1156 API RP 1160 API RP 579-1 ASME B31.4 ASME B31.8 AS 2885.3 CSA Z662

Types of defects	Assessment standards
Girth weld defects	API RP 579-1 BS 7910
Seam welding defects	API RP 579-1 BS 7910
Spiral weld defects	API RP 579-1 BS 7910
Cracks	API RP 579-1 BS 7910
Environmental cracking: stress corrosion cracking (SCC); hydrogen-induced cracking (HIC).	API RP 579-1 BS 7910

8.2.4 Residual strength and remaining life assessment

8.2.4.1 General

The ability to accurately determine the residual strength and any impact upon remaining life is dependent on the availability and accuracy of data relating to the defect. Where data is limited, the operator shall use conservative assumptions and shall update the assessments once accurate data becomes available.

Safety factors shall be determined by the operator and applied to all calculations of pipeline strength use for remaining life considerations.

The remaining life of defects shall be predicted based upon the defect growth, failure mode and an applicable safety coefficient. Where the defect strength does not satisfy the proposed service life at MAOP, the defect shall be scheduled for repair or removed or the MAOP adjusted.

Anomaly residual strength and predicted remaining evaluations based solely on ILI data, shall be only be conducted if the ILI data is correlated with the appropriate number of field verification excavations. The operator shall determine the appropriate number of verification excavations that demonstrate the correlation of the ILI results with an appropriate level of confidence. Defect residual strength and predicted remaining life calculations shall consider all of the relevant uncertainty and probability of exceedance associated with variables such as defect sizing, assumed growth rates and operation loads as part of the evaluation.

When conducting remaining life calculations, the defect repair time shall be time from the initial identification of the defect until the time the defect will be excavated for evaluation and possible repair. ILI results will be re-validated with ongoing excavation results and if applicable modifications to the defect sizing and predicted growth rate shall be undertaken.

NOTE API Std 1163 provides guidance on ILI verification.

When a defect is found that exceeds the acceptability criteria then immediate mitigation actions, such as reducing the pressure, defect removal or repair, shall be undertaken. The operator shall be able to demonstrate that the mitigation action taken has rendered the defect safe.

8.2.4.2 Acceptance criteria

Acceptance criteria for the different types of defects referenced shall be as stated from 8.2.4.3 to 8.2.4.7, unless otherwise determined by the operator or prescribed by regulations.

8.2.4.3 Acceptability criterion for corrosion

Immediate mitigation is required for corrosion anomalies with calculated failure pressure less than the design safety factor multiplied by MAOP or with depth greater than 80 % of nominal wall thickness.

Scheduled mitigation is required for anomalies can be operated safely at MAOP while growth calculation identified anomalies will become unacceptable. Mitigation shall be scheduled according to growth calculation.

8.2.4.4 Acceptability criterion for manufacturing defects

Manufacturing defects will normally have passed a hydro-test and therefore should remain capable of operating throughout the service life at MAOP. Where manufacturing defects are developing in severity, they shall be assessed and mitigated as corrosion.

8.2.4.5 Acceptability criterion for cracks

Immediate mitigation is required for cracks with calculated failure pressure less than the design safety factor multiplied by MAOP.

Scheduled mitigation is required for where the main crack development mechanism has been permanently but safe to remain in service. The remaining life shall consider ongoing fatigue. Mitigation shall be applied prior to the defect with calculated failure pressure being less than the design safety factor multiplied by MAOP.

8.2.4.6 Acceptability criterion for dents

Dents shall be assessed against local acceptability standards. Cracking associated with the dent shall be identified and ground out and the pipe supported as necessary. Where repair is not possible, the dent shall be removed. Dent dimensions shall be reassessed after excavation to take into consideration any re-rounding that have occurred.

8.2.4.7 Acceptability criteria for weld defects

Welding defects shall be assessed for their suitability for ongoing service. Where repair is necessary, suitable mitigation shall be applied until it can be completed.

Welding defects that are unsatisfactory and cannot be repaired safely shall be removed from service.

Assessment of planar defects should be considered as cracks, see Table 3.

8.2.5 Reporting requirements

A report shall be prepared that specifies the defect type, cause, actual dimensions, pipe and coating conditions and any relevant soil and topography information and the repair actions taken.

8.3 Pressure test

8.3.1 General

8.3.1.1 Pressure test, also known as hydrostatic testing or hydro-testing, is a pipeline integrity assessment method recognized by oil and gas transportation industry that evaluates a pipeline's capability to safely operate at a determined pressure (such as MAOP). Pressure tests are also used to determine if there are leaks.

8.3.1.2 Pressure test as described in this subclause is only for the integrity assessment of in-service pipelines.

8.3.1.3 Before conducting a pressure test the operator shall consider performing a risk assessment for both the applicability of assessment methods and procedures and the activities of the pressure test itself. Any remedial actions identified in the risk assessment shall be completed before proceeding with the pressure testing.

8.3.1.4 The operator shall consider results of risk assessments and severity of known defects to confirm the frequency and scheduling of any pressure test.

8.3.1.5 If the target pipeline operating pressure is higher than the initial design, then it is a matter of uprating, see 13.5.

8.3.1.6 Pressure testing shall use water as the testing medium for all pipelines unless the operator can demonstrate that the use water is not feasible. The use of non-combustible gas for pressure testing may substitute water as long as the associated risks are mitigated, and it complies with regulations.

8.3.2 Preconditions for use of pressure test on in-service pipeline

Selection of a pressure test to determine integrity of an in-service pipeline shall include at least one of the following:

a) Pipelines that are required to have pressure-test assessments from identified the pipe body threat to risk and/or integrity assessment.

b) The pipeline has been in operation at a pressure lower than the designed MAOP, and is considered to be operated at a higher pressure or MAOP.

c) Frequent incidents continue to occur after a number of integrity assessment methods for pipelines are performed, including ILI and direct assessment.

d) The medium or process conditions are altered from the design parameters.

e) Pipelines that have been inactive for over a year are returned to service.

f) Pressure testing shall be conducted on any replaced pipe segments.

8.3.3 Features to be considered for water pressure test

Test pressure shall be based upon local regulations, related risk assessment and operator practices.

The following conditions shall be considered when performing a water pressure test:

a) The operator shall consider the pipeline operating conditions and influences of geography and the impact of pressure testing with water. Such conditions can include impact of the pipeline shutdown, accessibility for repairs and replacements, water disposal, topological geography of the pipeline right of way.

b) The test pressure is normally dependent on the planned targeted operating pressure. The test pressure shall be obtained at the high elevation point of the minimum strength test section and shall not be higher than the pressure required producing a hoop stress equal to SMYS as determined by testing. An extensive safety assessment shall be conducted to ensure the pressure testing does not pose a threat to safety.

c) In cases of pressure testing on exposed and unsupported pipelines, the strength and capability of the pipeline shall be calculated and included in the risk assessment plan (to prevent unplanned permanent deformation).

d) Pressure testing shall be performed in accordance with original design standard and safety factors applied.

8.3.4 Pressure test risks

Pressure test can be a relatively dangerous activity within pipeline integrity management and can impact personnel safety. Risk identification shall be implemented prior to pressure testing by qualified personnel. Risks shall be identified and mitigated. Examples of risks associated with pressure testing include:

a) variances in material properties as process parameters can vary;

b) risks of water injection and drainage on future pipeline corrosion;

c) risks of pipeline failure incurred by considerable pipeline leak points;

d) risks of disturbance to entire system during pressure test;

e) risks of unplanned permanent damage to pipe materials and strain.

8.3.5 Management measures

Risk management of pressure testing is a dynamic process and the operator shall monitor and regularly update the risk assessment and its recommended activities prior to, and during the testing.

The operator shall ensure that safety and management controls are in place through the process. These controls shall include preparation of checklists to ensure completion of all works, collection and summary of post-test experiences.

The operator shall formulate a detailed pressure test plan that includes the identified risks. The operator shall also conduct a material property analysis to ensure the pressure test does not impact the materials. Where material properties are unknown, the operator shall conduct tests of the materials to determine their properties. The evaluation shall include calculation of the strength of materials used according to relevant standards and codes, and shall be included in the formal documentation of the pressure test.

The operator shall conduct an assessment regarding changes in pipeline stresses caused by the medium replacement and temperature variations; methods such as finite element analysis (FEA) may be used to identify stress changes requiring controlling.

The operator shall prepare emergency response plans in relation to pressure testing, to mitigate any safety or environmental consequences associated with pressure testing.

The operator shall ensure that personnel is adequately trained and qualified prior to pressure testing. Records of training shall be kept as part of the pressure-test activities.

The operator shall ensure that the pressure test plans include reviews of field conditions; accessibility and logistics for temporary facilities as needed for performing water pressure tests including capabilities to capture and dispose of testing product.

8.3.6 Monitoring of pressure test procedures

The operator shall ensure that personnel is available to comprehensively monitor for pressure changes caused by pipeline failures, and resulting forensic analysis in cases of pipes rupture during pressure testing.

The operator shall ensure surveillance over-pressurizing and depressurizing activities at both ends of pipe segments tested.

Line patrollers shall be arranged along the pipe segments tested to directly observe for any pipeline medium release or if there is any abnormal ground movement or changes.

The operator shall inform residents adjacent to right of way that the pressure test is occurring and assign relevant personnel to have evacuation emergency plans in place.

8.3.7 Review of pressure test results

Relevant personnel of the operator shall review and analyse process data during the pressure test to identify leak points and perform validation during excavation in order to directly acquire and collect integrity data as part of the integrity plan and pressure test records. .

The pressure test shall be monitored and recorded over time and form part of formal test documentation.

In the case of any leak points detected, the operator shall perform prompt repair measures including pipe replacement, or welding repair as determined by relevant personnel.

For any pipe segments that failed the operator shall perform a failure analysis (see 12.2) and mitigation shall be conducted to prevent reoccurrence.

8.3.8 Pressure test report

The pressure test assessment report shall include:

a) project information;

b) pressure test plan;

c) records of the pressure;

d) defects and anomalies detected;

e) repair-related information;

f) reassessment period;

g) conclusions.

8.4 Direct assessment

8.4.1 General

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity.

Direct assessment is applicable for three types of time-dependent defects: external and internal corrosion, stress corrosion crack (excluding fatigue related threats such as corrosion fatigue).

In general, direct assessment is applicable for the following conditions:

a) pipelines where ILI or pressure test is not possible;

b) pipelines that require costly renovation as evaluated by other methods; and

c) direct assessment is confirmed to be more effective than ILI or pressure test.

8.4.2 Direct assessment process

Direct assessment usually has a four-element approach:

a) Pre-assessment: It is used for determining feasibility of direct assessment by data collection and analysis, identifying assessment sections and choosing indirect inspection tools.

b) Indirect inspection.

c) Direct examination: Based on analysis of indirect inspection results, choose location and number of excavation locations and conduct a direct inspection of the pipeline surface. Such works require inspectors to have sufficient professional knowledge.

d) Post-assessment.

8.4.3 Direct assessment methods

Direct assessment method mainly includes external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA) and stress corrosion cracking direct assessment (SCCDA), etc. Relevant standards are provided for reference in Table 4.

Table 4 — Main types and references of direct assessment

Direct assessment method	Reference
ECDA	ISO 15589-1:2015, Annex D
	NACE SP0502
	NACE SP0210
ICDA	NACE SP0206 (dry gas)
	NACE SP0110 (wet gas)
	NACE SP0208 (liquid petroleum)
SCCDA	NACE SP0204

8.4.4 Limitations of direct assessment

Each direct assessment method is well-targeted and tailored for implementing integrity assessment on one main risk (e.g. ECDA is mainly established for external corrosion) and requires users to follow the applicable standards in their entirely. Direct assessment shall only be conducted by competent personnel knowledgeable in the method. Results of in-line inspection can also be considered when doing direct assessment.

8.5 Other assessments

The operator may consider alternative integrity assessment methods, such that the alternative integrity assessment shall be an industry-recognized methodology, and be approved and published by an industry standards organization.

For performance-based IMPs, techniques other than those published by standards organizations may be utilized. However, when utilizing a new technology, the operator should plan to ensure that it has demonstrated its ability to perform an adequate assessment and provide an equivalent understanding of the pipeline that is comparable to ILI, DA or pressure testing.

9. Mitigation

9.1 General

The results of assessments shall be used to determine whether the current prevention or mitigation measures are adequate, and if necessary, to specify what additional measures are required to mitigate any unacceptable risks identified by the assessment. Prevention and mitigation activities are designed to reduce the risk to an acceptable level by reducing the likelihood and/or the consequence of a failure.

The process of establishing and implementing effective preventive and mitigation measures requires suitable data collection, data integration, and informational analysis within the IMP. Data integration and the analysis can identify additional threats requiring attention. Most importantly, local knowledge of the operational environment around the pipeline and the incident history associated with certain components or circumstances is necessary.

Mitigation measures may include a combination of physical design changes (e.g. wall thickness), processes, and ongoing inspection, maintenance and repair programmes. Some common mitigation measures for different threats are shown in Table 5.

Table 5 — Mitigation measures for different threats

A	B	C1	C2	C3	C4
Feared event (failure mode)	**Root causes (potential): pipe body/ welds/ components**	**Physical phenomenon/ environment**	**List of defects**	**How to monitor**	**How to mitigate**
Immediate: flow restriction/ leak/rupture Future: flow restriction/ leak/rupture	Material Process Fluids Environmental factors Human factors	Mechanical damage	Gouges Dents Ovality Vandalism (off-take)	Visually ILI NDT Surveillance	Pipe protection Repair techniques Quality control Identification Communication Depth of cover Surveillance
		External corrosion related	External corrosion	Visually ILI NDT Coupon Surveillance ECDA	CP Material and coating selection Coating application Repair techniques Coating repair Hydrotest
		Internal corrosion related	Internal corrosion Erosion	ILI NDT Coupon Corrosion product Surveillance ICDA	Product quality Inhibitors Material and coating selection Coating application Repair techniques Hydrotest
		Incorrect operation	Crack Buckling Wrinkle Hydrogen embrittlement Seal failure	Visually Leak detection SCADA Pressure test	Quality control Repair techniques Pressure derating Maintenance

A	B	C1	C2	C3	C4
Feared event (failure mode)	**Root causes (potential): pipe body/ welds/ components**	**Physical phenomenon/ environment**	**List of defects**	**How to monitor**	**How to mitigate**
			Gasket failure		program
		Weld/pipe body flaws	Grinding Hydrogen embrittlement Hardspot Planar Volumetric imperfections	ILI NDT Visually	Quality control Repair techniques Pressure test Pressure reduction
		Cracks	HIC SCC Fatigue cracks SSC Corrosion fatigue Hook crack	Visually ILI NDT SCADA	Pipe protection during transportation Pressure regulation (cycles frequencies and amplitude) Coating repair Temperature regulation Repair techniques Quality control Pressure test
		Weather related	External corrosion	Visually ILI NDT Coupon Surveillance	Pipe protection
		Geologic hazard	Dents Ovality Hook crack Strain	Visually ILI NDT SCADA Surveillance	Pipe protection Repair techniques Pressure test Dig

9.2 Prevention of mechanical/third party damage

9.2.1 General

Integrity management requirements shall require protection against third party damage utilizing physical measures installed during construction and procedural measures during operations to ensure that the risk of third party damage is sufficiently low to be acceptable. Pipeline design shall ensure that the ultimate designs adequately cater for the operational ongoing requirements, including consideration of future urban development areas. They shall be reviewed regularly and updated as necessary.

9.2.2 Physical measures during construction

Physical measures during construction operate as a barrier to the potential activity and are generally installed at construction. They shall be designed for the particular threat that is anticipated over the life of the pipeline. They are only barriers not guaranteed protection against excessive force from large machinery.

9.2.3 Depth of cover

High pressure pipelines are generally laid below the depth that most other utilities lay their equipment. This provides a significant amount of protection from other utility works in the vicinity of the pipeline, particularly from crossing services. The depth of cover shall be determined during the design for the environments that the pipeline will pass through.

Depth of cover can be increased by pipeline lowering or ground level rising. This can be necessary where new infrastructure, such as a new road or railroad, is being built over an existing pipeline.

9.2.4 Pipe wall thickness

The pipe wall provides protection against third party damage by limiting the extent of damage rather than protecting against it. As the wall thickness increases the resistance to puncture increases.

The pipe thickness required should be determined during design to suit the environment that the pipeline will pass through.

9.2.5 Concrete capping/barriers

Concrete capping/barriers can provide a high level of protection against impact from third parties by providing a physical barrier that protects the pipeline whilst providing a warning to third parties of the presence of an underground obstruction that requires investigation. Capping may also be designed to provide side protection against boring. The thickness and strength of the concrete shall be designed to protect against the identified threat, however it cannot protect against repeated impact. The concrete cap and side shields shall be designed to not interfere with cathodic protection.

9.2.6 Marker tape

Marker tape can be laid during the construction phase in the trench but above the asset. The tape provides an early warning to third party excavators of the presence of the pipeline below.

9.2.7 Pipeline markers

The operator shall install permanent pipeline markers to alert anyone approaching a pipeline right-of-way of the presence of the pipeline. To be effective, the markers shall be visible in both directions at any point along the right-of-way and stand out from the surroundings. The signs shall be designed to promote pipeline awareness, identify the operating company and provide contact information including an emergency phone number. The signs shall instruct third parties not to excavate in the vicinity of the pipeline and shall be particularly located where risk assessment has identified increased risks from potential third party interaction.

All physical measures employed at construction shall be maintained throughout the life of the pipeline and not removed without a clear ‘management of change style’ review.

9.2.8 Procedural measures during operation

Procedural measures shall be applied as a result of risk assessment during the operational stage to provide information and guidance to third parties who might interact with the pipeline.

9.2.9 Right-of-way maintenance

To enhance detection of the pipeline casement, an operator should maintain the right-of-way to be clear of obstacles such as under-brush, tall weeds, trees, and canopy (where permissible). Keeping the rights-of-way clear in this manner facilitates aerial surveillance, alerts land occupants and others to presence of a pipeline corridor and increases the likelihood that anyone entering the right-of-way will see one or more permanent markers indicating the presence of an underground pipeline.

9.2.10 Public awareness

The operator shall establish a public awareness program to inform the public, utilities, contractors and other third parties of the dangers of excavating near a pipeline.

The operator shall provide methods of communication regarding the presence of the pipeline. As a minimum, a dedicated public phone number shall be available to allow contact from the public regarding activities that can impact the pipeline right-of-way or leakage from the pipeline. Other forms of communication channels may include websites or mobile messaging.

9.2.11 Pipeline surveillance

The operator shall conduct surveillance of each right-of-way regularly using aerial patrol or other means, such as ground patrol, at a frequency to suit the identified risk.

When using aerial patrols, the operator should use a separate observer in addition to the pilot in order to improve the effectiveness of this type of right-of-way surveillance. Aerial surveillance with high resolution cameras can provide geo-referenced photography of features identified along the right-of-way.

9.2.12 Communication between operator and with third parties

The operator shall have a dedicated phone number for contact from third parties. Typically this will be used for emergencies and contact from the field for other operational purposes.

Where one-call systems operate, the operator shall utilise the facility wherever practicable to ensure that third parties have easy access to pipeline information and are professionally managed through the liaison process.

9.2.13 Locating and marking

The operator should determine if any known third party excavation activities could affect one of the operator’s pipelines. Lines of communication should be established with the third party. If the excavation activities will encroach onto the operator's right-of-way, the operator shall locate the pipeline that could be affected and mark its location with temporary markings prior to the excavation work commencing. The operator shall have standard procedures for such activities and may require a pipeline inspector to be present on site throughout the works.

Permanent and temporary markings shall indicate the location of the centreline and size of the pipeline or the sides of the pipeline (or pipelines if it is a multiple-pipeline right-of-way). The operator shall renew the markings if they become displaced by excavation or if they become degraded with the passage of time until all excavation activity has ceased. Markings without physical or visual identification of the pipeline location should be considered advisory and no excavation shall occur until the location is verified.

9.2.14 Site communication and monitoring of excavation

The operator, besides locating and temporarily marking the pipeline, shall establish a communication link with the excavator that may involve the following:

) Exchange of names of contacts and phone numbers and agreement to have a designated observer from the operator present during relevant excavation activities.

b) Agreement excavation schedules including that the operator's observer shall be present when excavation is approaching within a specified distance of the pipeline.

c) Issuance of a written procedure for the excavator to follow that includes a distance-to-the-pipeline limit within which non mechanical excavating techniques should be used. The operator should provide direct onsite supervision of the excavation if the pipeline is to be exposed. Activities around any exposed pipe, including procedures and activities for back-filling the pipe that will avoid pipeline damage such as to the coating or any CP attachments, should be supervised.

9.3 Corrosion control systems

9.3.1 External corrosion

All new pipelines shall be protected from external corrosion by the installation of a protective external coating and an adequate CP system. ISO 15589-1 and NACE SP0169 shall be referred to as minimum criteria for the application and use of CP to mitigate external corrosion of a buried steel pipeline. CP shall be applied to all existing pipelines as well, whether coated or bare.

The operator shall determine the minimum level of protection that shall be maintained. CP levels shall be monitored to confirm that they are operating satisfactorily and providing suitable pipe-to-soil potentials. At areas where the potentials fall below the levels required, the operator shall investigate the cause of the low potentials and mitigate them. Mitigation shall consist of bringing the CP levels into compliance either by making sufficient repairs to the coating and/or by increasing the current outputs of existing anodes or adding anodes to increase the current output necessary to achieve the recommended levels. The operator can also employ one or more of the ECDA techniques to enhance the mitigation of external corrosion of a given pipeline segment. Induced AC corrosion has become better understood and should be controlled. ISO 18086, ISO 15589-1, NACE 35110 and NACE SP0177 provide information on the mitigation of induced AC corrosion.

9.3.2 Internal corrosion

If the fluid being transported in a pipeline has the potential to corrode the internal surface of the pipeline, the operator shall determine the nature of the corrosion that could occur within the pipeline and shall take adequate steps to mitigate it. The most common form of internal corrosion occurs in conjunction with the build-up of water and/or the deposition of sediment.

These phenomena are not only a function of the fluid characteristics, but also a function of the flow velocity and the elevation profile. The operator can monitor critical locations by installing coupons or resistance-monitoring devices or by directly measuring wall thickness to detect metal loss. Mitigation steps may include, but are not limited to the following:

a) the injection of a suitable inhibitor or biocide;

b) frequent cleaning with cleaning tools to remove sediment and water;

c) maintaining a minimum flow velocity to minimize water and sediment entrainment;

d) flushing dead-leg segments and valve bodies where fluid can be static and not influenced by general pipeline fluid flow.

9.3.3 Stress corrosion cracking

Effect of coating on SCC shall be considered for pipelines, which include:

a) prevention the formation of cracking environment;

b) prevention of contact between the electrolyte solution and the pipe surface of the steel;

c) allowance of the CP when the coating layer damaged.

Adequate CP can prevent SCC if it reaches under disbonded coatings.

Stress shall be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.

Elevated temperatures have strong accelerating effect on high-pH SCC. For near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.

9.4 Preventing or mitigating releases associated with weather and geophysical events

The operator shall establish prevention and mitigation plans against damage from weather and external forces. Such events can include, but are not limited to the following:

— extreme cold;

— high winds;

— flooding;

— geophysical events, such as earthquakes, landslides;

— land erosion, or subsidence in their specific environment.

Prevention and mitigation activities that the operator should consider are:

a) inspection of drain valves and pipe extensions prior to cold season for pipeline that may contain water to eliminate freezing that lead to failure;

b) shut down and, if feasible, purging pipeline segments that could be damaged by impending hurricanes or floods;

c) provision for expected movement of a pipeline to occur without damaging the pipeline at seismic fault crossings, unstable slopes, or areas of subsidence;

d) routine inspection of the pipeline right-of-way to identify and monitor areas of developing soil instability, landslides, and subsidence;

e) conducting pipeline patrols as soon as feasible after the passage of severe weather, flooding, or an earthquake;

f) monitoring river crossings for unintended exposed pipe at crossings or riverbanks;

g) maintain GIS data for fault zones, land use, etc. for use in risk and integrity assessments;

h) land movement and pipe strain monitoring;

i) maintaining drainage and erosion control, such as:

   1) diversion berms;

   2) gabions;

   3) ditch plugs; and

4) sub drains.

9.5 Management of unintended releases

An IMP shall contain protocols for detecting leaks and for limiting the consequences in the event of an unintended release. Elements of the plan shall describe the means and procedures for:

a) minimizing the time required for detection of a release;

b) minimizing the time required to confirm and locate a release;

c) minimizing the volume that is released;

d) minimizing emergency response time;

e) protecting the public and limiting adverse effects on the environment.

The operator shall consider whether a release detection system is necessary for the transported fluid and the environment through which the pipeline passes. The role of release detection is to minimize the time required to detect leaks from a pipeline system. The type of system used shall be carefully reviewed to ensure that it meets the needs of the operator.

The operator shall select, install and maintain a system or systems appropriate for the length and size of the pipeline, the type of products within the pipeline, and the release/spill scenarios for critical locations. The abilities to detect a release of a certain minimum size and to locate where such a release has occurred will depend on the type of leak detection system or systems employed. Common release detection methods and their characteristics are summarized in Table 6. Some release detection systems are applicable only for hazardous liquid pipelines, such as the pressure point analysis system.

All real-time release detection systems shall be tied to the SCADA and operational monitoring systems and the operating personnel shall be trained and qualified to operate and interpret results of each release detection system used.

Table 6 — Release detection method examples

Method	**Locates release**	**Data sampling availability**	**Advantages**	**Disadvantages**
Periodic auditory, visual, and olfactory inspections	Yes	Periodic	Simplicity	Delayed recognition of leak between intervals. Can involve odorant injection
Mass/Volume balance	No/yes?	Intermittent based on comparison time	Simplicity	Transients tend to cause false alarms
Dynamic flow modelling	Yes if analysis is done	Continuous even when transients are present	Best method to detect small leak rapidly	Complexity and cost
Tracer chemical	Yes	Can be either continuous or one time	Accurately locates small leaks	Needs to add something to the product and requires air sampling
Release detection cable	Yes	Continuous	Accurately locates small leaks	Next to impossible to retrofit to an existing pipeline
Shut-in leak detection	No	Periodic	Simplicity	Requires shutting off flow and accurate pressure monitoring
Pressure point	Yes, if	At the sampling rate	Simplicity	Not suitable for large

analysis	multiple points used	except during transient operation		pipelines or compressible fluids
Acoustic leak detection	No	Continuous		
NOTE There is some advantageous to employ a combination of these methods. For example the computational methods could be augmented by a volume balance approach and/or tracer chemicals or a stand-up test could be used on occasion as a check on the real-time methods.				

9.6 MAOP reduction

A reduction in operating pressure can be used to reduce the risks associated with threats to pipeline integrity, that are dependent on hoop stress as generated by the fluid pressure, such as metal loss, SCC, mechanical damage, or the growth of an anomaly through pressure-cycle-induced fatigue. A pressure reduction can be either permanent or temporary. The safe operating pressure for the defect shall be determined by an engineering assessment and documented and advised to the pipeline controllers.

If the operator is unable to meet repair or reassessment schedules, it shall consider implementing temporary pressure reductions. For time-dependent threats, such as corrosion, other risk control measures shall be applied in parallel with a pressure reduction. The operator shall ensure that the determined MAOP provides a suitable factor of safety.

MAOP shall not be lifted without a documented engineering assessment that demonstrates the pipeline is safe to be operated at the revised pressure.

9.7 Emergency response

To limit the consequences of a release, the operator shall provide a timely and sufficient response. For a liquid pipeline, physical barriers can be appropriate to limit the spread of released product and to recover as much of the product as possible.

The operator shall update the emergency data, which are listed in 12.1.3, periodically. Emergency exercise shall be carried out periodically to train response personnel, to test response equipment, to improve procedures and verify response capability under numerous conditions. The operator shall evaluate its response after any exercise or emergency to identify opportunities for improved performance.

Agencies, such as law-enforcement and fire-fighting agencies, should be informed of and considered for involvement in emergency response exercises.

The requirements and description of emergency response and failure management are specified in Clause 12.

9.8 Defect repair

9.8.1 General

Anomalies that are assessed as unacceptable defects at their MAOP through integrity assessment activities shall be repaired or the MAOP shall be reduced to provide an appropriate level of safety.

The objective of repair is to ensure that the repaired pipe is fit for service at the designed MAOP over the remaining pipeline life. The repair shall provide for sufficient structural integrity to withstand all the identifiable forces to which the repaired area can be subjected during operations, including the MAOP and cyclic pressure fluctuations, and with an acceptable safety margin in accordance with local practices, regulations and standards.

Repairs can include:

a) grinding to remove stress concentrators;

b) excavation and relocation to remove strain;

c) sleeving or clamping to improve pipeline strength;

d) sleeving to remove hoop stress from the carrier pipe;

e) pipeline excavation and relocation to remove deformation strain.

9.8.2 Repair strategy

The repair strategy shall include, but is not limited to the following:

a) pipe material;

b) pipeline operating characteristics;

c) pipeline configuration;

d) pipeline location;

e) nature and severity of defects;

f) repair material options;

g) hazards to staff.

Where an anomaly is found to be unacceptable, a temporary MAOP can be required until a permanent repair can be carried out. A temporary repair can enable a higher MAOP until a permanent repair can be completed. MAOP will be set by engineering calculation and documented.

Temporary repairs can be necessitated for operating purposes. Such temporary repairs shall be approved and made in a safe manner, be documented within in the IMP, and be in accordance with sound engineering principles and any established operator procedures and practices. Temporary repairs shall be made permanent or replaced in a timely manner.

The repair strategy shall comply with an approved procedure and technique. The permanent repair shall be designed to be suitable for the long-term operation of the pipeline at the designed MAOP.

Permanent repairs shall be made to a pipeline, subject to the following conditions:

a) The internal pressure has been reduced to a level to ensure safety during the repair operation.

b) When necessary, the impact of grinding in the area containing the defect shall be assessed.

c) Safety procedures and precautions are followed in accordance with approved procedures and/or recognized practices.

d) Cutting and welding procedures shall ensure that pipe walls are not reduced in thickness or weakened.

e) Where a section of pipe containing a defect is replaced, the replacement pipe shall be pretested and its properties verified such that the integrity of the pipe is not less than that of the section to be replaced. The repaired section, if applicable, shall not impede any future cleaning or in-line inspection operations.

f) Pressure-bearing repairs shall not reduce the established MAOP of the pipeline.

g) The use of mechanical devices, other than full-encirclement welded sleeves to repair pipeline defects, shall be documented for type, installation and pressure rating. The operator installing such devices shall use trained and competent personnel to conduct the installation and testing work.

NOTE The use of reinforcement sleeves or mechanical devices for permanent repair of pipeline internal corrosion defects is not recommended as the passivation of the internal corrosion cannot be guaranteed.

9.8.3 Repair method selection

The applicability of the repair methods to various types of defects should reference CSA Z662, ASME B31.8S, API RP 1160 or other suitable standards or recommended practices.

Repair practices of the operator shall include processes for the selection and approval of acceptable defect repair methods, as well as measures of effectiveness, feasibility and availability, cost and convenience.

Replacement of line pipe to remove multiple defects in one operation shall be considered where multiple severe defects exist.

9.8.4 Factors in repair planning and execution of repair activities

At least the following factors shall be included in the planning and execution of repair activities:

a) MAOP during repairs: The safe operating pressure for the pipeline defects shall be calculated. Prior to excavation, the operating pressure shall be reduced by a safe margin below recent experienced pressure at the defect position.

b) Positioning: GPS using ILI information is preferable to locate and document excavation position. Joint numbering may can also be used for position reference of the repair.

c) Excavation site: This refers to excavation location for the repair of identified pipes. The maximum allowable length of unsupported pipe should be calculated by relevant personnel and/or conforms to the length restriction as permitted by the procedures and practices of the operator.

d) Confirmation: The pipes to be excavated shall be confirmed as the targeted pipes for repair using such references as pipe length, clock position of defects, and clock positions of upstream and downstream pipe-manufacturing welds.

e) Validation: Where practical, the effectiveness of the assessment method and its data sources should be confirmed through direct examination and/or inspection practices prior to repairs being carried out.

f) Inspection: Inspection of all repairs carried out shall be completed prior to backfilling.

g) Re-coating: All pipe, repairs and fittings shall be recoated with an appropriate coating to provide corrosion protection, and re-coating of all repairs carried out shall be completed prior to backfilling.

h) Backfill: Procedures and measures shall be followed to avoid pipeline damage and subsidence during backfill activities after the repair is completed.

i) Documentation of repair activities: Records should include details of the activities listed in items a) to h), including coating condition as found, surface preparation method, extent of corrosion damage, repair method used and details of re-coating applied.

9.8.5 Considerations of in-service pipeline welding

The following measures shall be considered for in-service welding activities used as part of pipeline repairs:

a) development of in-service weld procedures to suit the field weld conditions;

b) depressurization of gas pipelines by reducing inventory (which is preferred over venting);

c) preheating before welding;

d) avoidance of welding damage, such as arc burn, burn through by heat input control, electrode size limits; and

e) prevention of hydrogen-induced cracking.

10. Performance measurement and improvement

10.1 General

The integrity program shall be periodically reviewed, at least annually, to evaluate the adequacy of the IMP's processes, the extent of implementation and the effectiveness in achieving the intended results. The operator shall identify goals and objectives for its IMP. As part of the continual improvement process these goals and objectives shall be adjusted accordingly. To facilitate the integrity program evaluation, the operator shall use performance metrics and audits. The results of the performance metrics and audits shall be regularly reviewed by both the IMP personnel and by management to evaluate the IMPs adequacy, implementation and effectiveness. This review will provide feedback for continual improvement of the IMP, which can include recommendations for corrective and preventative actions if deficiencies are identified.

10.2 Performance measurement

10.2.1 The operator shall develop performance measures to enable the evaluation of IMP results. The measures shall be a combination of leading and lagging measures. Leading measures are proactive, for example number of ILI features excavated, and provide an indication of how the IMP plan may be expected to perform. Lagging measures are reactive, for example number of leaks, and provide an indication of the outcomes of the program and illustrate the IMP performance. The performance measures shall evaluate the representative sections of the IMP.

NOTE ASME B31.8S and API RP 1160 provide examples of performance measures. Example for performance measurement is also shown in Annex E.

10.2.2 The operator shall evaluate the performance measure results at least annually and the analysis shall identify any trends and areas for improvement. The operator shall compare the performance measure results between different segments in the same pipeline system or different pipeline systems in different areas. The information obtained shall be used to evaluate the effectiveness of preventive and mitigation actions or overall IMP, and to analyse and identify the improvements. The operator shall also compare its results with industry benchmark trends to identify areas for improvement.

10.2.3 A formal performance measurement report shall be prepared including the results, recommendations and requirements for improving performance. Results of performance measurement and the benefit of integrity management shall be communicated to relevant stakeholders.

10.3 Management review

The operator shall develop a process to conduct annual management reviews of the performance results in reporting the operator's goals and targets. The management review will identify areas for continual improvement of the IMP.

10.4 System audit

10.4.1 An audit of the IMP shall be conducted on a minimum 5-year basis to enable the operator to identify any non-conformances with the adequacy, implementation and effectiveness of the IMP. The audit shall be conducted by the operator deploying persons independent of the development and implementation of the IMP or by an independent third party.

10.4.2 Any findings of non-compliance shall be documented and corrective actions shall be proposed, implemented and monitored.

11. Data management

11.1 Data acquisition

11.1.1 Data acquisition content

Pipeline integrity management shall cover the entire life cycle of a pipeline. Data sources for pipeline integrity management include information relating to design, materials, construction, commissioning activities as well as for operating, maintenance, repair and abandonment data. Data resources also contain survey records, environment data, social resource data, failure analysis, emergency plan, etc.

Annex F provides data categories and a suggested data acquisition process for pipeline integrity management. Not all pipelines will need all data categories as in Annex F.

The operator shall gather and maintain the necessary data for adjacent areas for consideration of integrity management, particularly items that impact pipeline integrity threats and failure consequence assessment. The operator shall determine and establish distance ranges required for each category based upon failure consequence (e.g. rupture of a gas pipeline might consider an impact distance 400 m). Figure 5 provides an example.

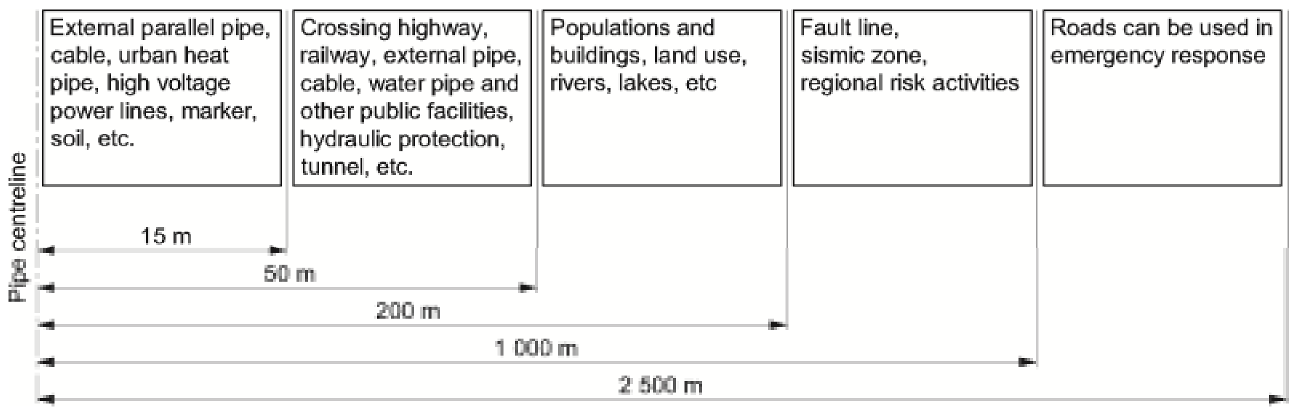


Figure 5 — Data acquisition range

11.1.2 Data acquisition method

11.1.2.1 Centreline measurement

A baseline centreline survey shall be developed during pipeline construction and completed before backfill. The surveyed pipeline coordinate points shall include, but not be limited to, elevation, the depth of cover measurement, and reference circumferential weld pipeline vertex (12 o'clock), bend corner points and intersections with other infrastructure such as roads, railways, other pipelines, waterways, buildings, etc.

NOTE ISO 13623 provides guidance on construction surveys.

During operation and maintenance activities, the operator shall maintain and update survey data as appropriate. For pipeline sections that a pipeline locator or ground penetrating radar cannot be used, an alternative survey or data analysis should be documented and used to establish the local centreline.

Where a pipeline is re-aligned, the new centreline shall be established and pipeline records shall be updated accordingly to form a new baseline.

11.1.2.2 Data acquisition for pipeline facilities and landbase

Information of the pipeline facilities and landbase shall be obtained during the pipeline construction phases as part of the survey and digital pipeline data collected. During the pipeline construction phase, the operator shall consider gathering information of surrounding geographic features and other assets.

Data acquisition should include digitization activities such as the transfer of paper records formed during construction and operating periods into the pipeline integrity management system. Such records can include: sourcing and quality records, operating records, repair records, examination and construction source records and maps or remote sensing images.

11.1.3 Data alignment

Pipeline data shall be aligned according to surveyed results which can include joints, girth weld number, or other unique reference in geospatial reference coordinates. The description of the pipeline properties should align to girth weld number. Where GIS is not applicable, pipeline ancillary facilities and surroundings information should be aligned to a referenced land mark, such as a permanent marker, or specific geographic references.

Data shall be aligned with construction data and operational integrity data. The basis for alignment will vary according to the accuracy and type of data.

The baseline alignment of construction and operational integrity data shall confirm to the following requirements:

a) A baseline alignment shall be completed that defines the centreline reference. This baseline alignment shall be from original construction surveys or from aligned mapping data from intelligent inspection.

b) If internal inspection is carried out, alignment shall be referenced to internal inspection circumferential weld number. If internal inspection is not done, the centreline data alignment shall be based on surveying. Where gaps in accuracy of the survey record are identified, the operator shall update the centreline reference using external inspection and supplemental surveys.

NOTE Internal inspection using mapping methods can generate direct centreline data with high precision. Internal inspection data will allow future alignment of external inspection data to internal inspection mapping data such as efficient matching of locations of anticorrosive coating defects and pipeline defects.

11.2 Data transfer

Data for a pipeline shall transfer from construction to operator prior to hand over. The operator shall establish a transfer procedure and system to realize accurate data exchange for initial operations. The operator shall resolve discrepancies in data through the use of ILI, external inspection, etc.

Pipeline facility data shall be submitted in either digital or hard-copy format. Among them, centreline data shall be submitted in standard format. An example is shown in Annex G.

11.3 Data integration

11.3.1 General

The data management system shall enable data integration and inquiry. Data integration generally refers to the process of utilizing two or more data sets to identify conditions of interest on the pipeline. In more advanced applications, data integration processes can include computer applications that spatially align and correlate the available data along the pipeline with predetermined criteria and rules.

NOTE 1 Data set examples include ILI, CP annual survey, close interval survey, depth of cover, and electronic flow restriction device locations.

NOTE 2 Data integration example include comparing the results of a CP survey with an ILI run to identify where metal-loss corrosion corresponds to poor CP protection.

11.3.2 Data integration requirements

Various data elements used to assess the consequence of a threat and its likelihood might change with time. The need for these changes can be caused by various factors including modifications to operating practices, changes in land use, pipe properties, reroutes, and new lines, as well as changes in pipeline surroundings changes due to encroachment. The operator shall have management practices that ensure that data used for risk assessment is accurate and current.

The operator shall provide ways to update data content and means to validate and check updated data. Any automated calculations and/or management considerations shall use updated and validated datasets.

Data integration requirements should include the following specified elements:

a) Storage checking: Stored data should be routinely validated to ensure consistency and its integrity.

b) Update of data content: All changed asset information, e.g. coating or replaced pipeline sections, shall be collected and stored including information relating to the local environment and other assets in the vicinity. The integrity management system should be updated as necessary and will utilize the data.

c) Update checking: Periodic checks should be made to ensure that the data is current. Where urban growth has or will occur, checking should be more frequent.

d) Version management: All updates shall identify version details and these data comparison of historical data with current data shall enable changes to be assessed in the asset and the surroundings.

e) Data modification rule: Modifications of the pipeline system data shall be subject to a management of change procedure that shall address the continuing safe operation of the pipeline system. Documentation of changes and communication to those who need to be informed is essential.

The modification of pipeline centreline requires procedure for examination and approval. Updates should be managed to ensure data's safety and efficiency.

Base data prior to updating should be retained for information.

12. Pipeline integrity management within emergency response planning and failure management

12.1 Emergency response planning

12.1.1 General

Emergency response planning plays a crucial role in ensuring an organization is ready to act and is able to sufficiently deal with emergency situations on its pipeline networks. Pipeline integrity management is designed to control the risks of failure by managing the pipeline and its environment throughout its life. No method can be considered 100 % successful with human error, third party risks and severe natural events defeating the control barriers in place. Emergency planning is therefore necessary to prepare for and minimise the consequence of a failure.

The IMP process provides valuable information that shall be used when emergency response plans are developed. Integrity management personnel shall be included in the emergency response organization to provide known information of the threats, consequences and conditions of the pipeline assets.

12.1.2 Emergency plan preparation

Emergency planning is focussed upon logistical and command activities; however the planning is supported by proactive assessment of the pipeline risks and environments. All pipeline events shall be reviewed and assessed during the planning phase, however catastrophic events shall be given extra attention due to their potential impact.

The operator shall identify pipe segments involving critical consequence areas (see 6.6.2) and prepare targeted emergency plans for such segments. The operator shall identify potential failure types, their consequence and the environment involved to enable specific response preparedness measures to be implemented for those locations. These measures can involve operational pipeline shut down procedures, 24/7 duty call, specialist materials, equipment and contractor on-call stand-by requirements and consider locational challenges and local regulatory requirements.

12.1.3 Preparation for emergency data

The operator shall prepare technical records, documents and drawings required for the emergency planning. Access to such documents shall be readily available to the response team and can include:

a) Drawings of pipeline routing, isolation valve locations and operability (automatic or manual), CCAs (environmental, culturally significant, high population, waterways, etc.), images or maps of surrounding pipelines, and a pipeline elevation profile (critical for considering potential pipeline liquid draining volumes). GPS coordinates of critical intervention points to communicate to emergency response units are crucial. Mapping of water-body velocities and their seasonal changes along the pipeline route will also aid in determining the potential location of the spill after time-zero of the event.

b) Operating parameters include product properties within the pipeline, typical pipeline operating temperature, pressure and flow, delivery requirements, compression/pumping/flare options, etc.

c) Emergency preparedness exercises are crucial in training operator response teams to the various threats. They also offer a valuable opportunity to identify gaps in the emergency response planning. Detailed verifiable field scenarios are best practice allowing for understanding for potential issues that could occur in a real event. Involvement of upper management and media relations personnel shall be incorporated to assess the readiness of the different units within the operator's organization. Debriefing and summarizing the findings and the creation of an action plan to address the findings are keys for continual improvement for emergency preparedness and event management. Performing emergency response exercises in collaboration with peer group companies are beneficial due to shared practice and learning opportunities.

The operator shall determine the threat from product release upon the surrounding areas at any point along the pipeline, based on pipeline imagery, maps, hydraulic and geologic conditions. The emergency plan shall outline any special measures prepared or required to contain the threat and for the coordination of the emergency response teams and liaison with downstream and upstream parties.

12.1.4 Emergency response

In case of an emergency, the operator shall have an emergency organization structure that can deal with emergency situations. Shutting down the affected pipeline or segmenting the affected section by closing block valves shall be considered. The operator shall follow its emergency response program that deals with emergency planning zones to determine whether warning alarms or evacuation is appropriate for the affected population. A few variables involved with creating an emergency planning zone can include type of product transported, the release location and the surrounding population and environment data related to the pipeline.

For pipelines for liquids, the diffusion path and potential pollution should be taken into consideration. The operator shall determine the nature of the threat to surrounding waters possibly affected by product release, based on pipeline imagery, maps, hydraulic and geologic conditions. Timely coordination and reporting will include the release time and the locations of threatened areas. Reporting to the emergency rescue team should include instructions for on-site liquid recovery and capture operations where relevant. The use of the surrounding water velocity information is extremely useful in setting up multiple containment areas downstream of the water source to limit the area of impact on the water body.

Often, the integrity team will not be involved directly with the initial ground efforts to control the situation. However, they will play a key role in reviewing available pipeline data close to the reported failure location to determine if any known indication previously was detected via monitoring or inspection data. Feature information from database records may be used to identify possible leakage points, which in turn assists with equipment preparation for the response crews.

12.1.5 Emergency response management system review

A performance review of the emergency response shall be completed with a focus upon the management systems, procedures, policies and activities relating to integrity management, response management and personnel competence. Prior emergency preparedness requirements should be reviewed and assessed against actual usage for continual performance cycle.

12.2 Failure management

12.2.1 General

Where a pipeline has failed, the failure segments shall be either removed from service or mitigated via an approved engineering approach. Where the cause is not obvious, the segment shall be forensically analysed as per 12.2.2. The failure analysis report shall be made available to the incident investigation team and integrated into the IMP review.

The operator shall analyse the root causes of all pipeline integrity events that cause or can cause loss of containment, including management system changes that can have contributed to the incident. These events can include: auxiliary equipment failure incidents due to leakage, status of pipelines failing to meet expected operational functions as a result of pipeline defects (fatigue or erosion, etc.), status of design requirements or loads that are beyond expectations as a result of any third-party construction, natural and geologic disasters, or other external factors. Several methods currently exist both commercially based and within the operator' organization. Examples are bow-tie assessments and why tree analysis.

Failure management shall analyse both the root causes and contributing causes. This analysis can involve: analysis of the emergency response effort, failures related to non-documented changes in management systems, and reviews of any identified weaknesses in the integrity program that led to the failure occurring.

12.2.2 Failure analysis

The operator shall develop a failure analysis plan specifying the required test methodology to be used for typical failures according to best known practices and expertise available in accordance with local regulations.

Background information to be included in the analysis shall be identified. Such information shall include, but is not limited to the following:

a) condition of pipeline segments or station equipment, based on inspection reports;

b) operating record of the pipeline or station equipment, including pressure measurements, temperature measurements and properties of the product medium;

c) maintenance and failure records of pipeline segments or station equipment;

d) material selection, manufacturing methods and thermal treatment history of pipeline segments or station equipment (as well as acceptance/commissioning test results); and

e) prior risk assessment.

12.2.3 Incident investigation report

The incident investigation report shall be prepared by competent personnel within the operator's organization, including at least one individual with approval authority of procedures. Personnel for the incident investigation and analysis shall possess professional competence required for investigating incidents (e.g. incident investigation training) and be capable of understanding the technical process of how the equipment functions. In cases of complex investigation or where experience is not present within the operator's organization, third party experts should be considered to assist as necessary. The extent of the incident investigation and analysis shall be determined from the complexity of the incident and its severity. The senior management staff of the operator shall play an active role in the management of investigations into major failure incidents.

The incident investigation report shall include, but is not limited to the following:

a) background and introduction:

b) incident investigation results;

c) incident discussion and lessons learned;

d) conclusions and recommendations.

The operator shall fully implement improvement measures as raised in the incident investigation report to avoid future incidents of a similar nature. The operator shall also review the performance level of the IMP through analysis using the incident data and other data of known incidents.

12.2.4 Remedial and preventative measures

The operator shall prepare and implement remedial or preventative measures to remove the threat of a repeat incident, including any specific lessons learned relating to the failure recovery phase. Such measures should include, but are not limited to: a risk assessment on measures taken including procedures for corrective and preventative measures, and implementation of a tracking and monitoring system on the remedial and preventative measures put in place to ensure root causes of the incident are mitigated.

The implementation plan of corrective and preventative measures shall meet at a minimum the following requirements:

a) specific timeline for implementation with a designated action owner;

b) process for monitoring the close out of recommendations at a management level;

c) existence of creation of relevant procedures for the corrective and preventative measures proposed.

12.2.5 Failure recovery prior to restart

The operator shall carry out an engineering assessment of the failed pipeline section to confirm that any other indications which are identified as having the potential to induce further failures have been addressed and that the risks and/or consequences have been mitigated in accordance with the IMP, before a restart of the pipelines. The decision to restart the pipeline and the analysis shall be documented, and where required approved by the local regulatory body.

The operator shall collect all the documents related to emergency measures taken, including all records of changes to pipelines due to the emergency response as according to 12.1, and all analyses of the trends of failure as per failure statistics.

12.2.6 Trend analysis of pipeline incidents and causes

The operator shall perform statistical analysis and track trends of incidents either by itself or by participation in relevant organizations, to provide basic data to contribute to the effectiveness of pipeline integrity management. The incident data collection shall be made to comprehensively meet relevant requirements to ensure data validity and accuracy. Incident data shall be recorded in a consistent manner to aid in future comparison analysis. Qualified personnel shall perform the statistical analysis including a review and documentation of the quality of data, such as to minimize the use of suspect data in the analyses.

Incident data collection shall include as a minimum: incident classification types, causes classification types, and common calculations of the magnitude or scale of the incident effects. Example for incident data collect is shown in Annex H.

The designated qualified personnel or group that performs the statistical analysis shall make periodic analyses (every year or every five years) on any trends of pipeline incidents using broader data sets as available. Trend analyses can be divided into overall trend analysis and trend analysis for any certain type of incident.

13. Remaining life assessment and abandonment processes

13.1 General

At a certain point in the pipeline’s lifecycle, the pipeline enter into a period where the rate of risk factors being introduced within a given time period will exceed the practicality and ability to mitigate those risks such as a high population of growing corrosion defects that cannot be repaired in a timely manner which causes high operation risks. In the event of such situations, a pipeline life assessment should be carried out.

A pipeline life assessment shall be made to verify that the risk of continuing to run the pipeline is still lower than the acceptable risk without impacting public and environment safety, while still meeting economic targets for the operator.

A pipeline life assessment shall also be performed if the pipeline operational life exceeds, or will exceed the original design life, or if the economics of the pipeline operations becomes unfavourable as a result of upstream and downstream changes in pipeline operation.

An effective pipeline life assessment shall include, but is not limited to the following:

a) pipeline integrity assessment;

b) risk assessment;

c) economic life assessment;

d) physical life assessment;

e) effective life (safe and economical operation life) assessment;

f) mitigation or re-inspection suggestions for risks related to use of life extension, e.g. suggestions about safe operating pressure (optional);

g) review on applicability of procedures in relation to operation and maintenance, emergency response, safety and environmental program (optional);

h) assessment on nonconforming items against current law, regulation or standard;

i) analysis of differences between previous and current specifications on design, pipe manufacture and construction.

Repair measures required to mitigate hazards (anticipated to occur in period of life extension) of the pipeline system shall be developed when necessary.

If the remaining life of a pipeline is assessed to be beyond the design life, the pipeline shall undergo life extension remedial actions. If a pipeline cannot run safely and economically, the operator shall consider decommissioning, abandoning or down rating the pipeline pressure.

Pipelines that have been idle shall be re-used or re-designed for other purposes (see 13.4).

One outcome of pipeline life assessment can conversely indicate that the pipelines may be able to run safely and economically at a higher operating pressure and would be uprated in operational production.

13.2 Assessment process

13.2.1 General

The assessment process for a pipeline remaining life is illustrated in Figure 6.

Initially, an integrity assessment shall be performed. The details of data collection, risk assessment and pipeline integrity assessment methodology respectively shall be followed. The integrity assessment, economic life assessment and risk assessment shall be completed to provide an initial baseline result.

From the integrity, physical economic and risk results, conclusions for remaining pipeline life assessment can be determined by the operator to decide if the assessed pipeline should continue to operate, be down rated or be abandoned.

In the case of distinct physical life issues, the physical life results shall be considered as the dominant factors for decision making. Otherwise, the minimum values of physical and economic life will be taken as the remaining life of the pipeline (considering that the construction period is included). The pipeline risk assessment can provide strong technical support for physical life assessment, while economic costs of integrity requirements involved for the operator's decision.

If the pipeline is considered to be still viable, based on assessment results, pipeline repair and maintenance activities shall be performed.

A life reassessment shall be scheduled based on the previous life assessment results to support continuous safe pipeline operation.

If the assessment results show that the remaining life of a pipeline is zero, then the pipeline shall be abandoned.

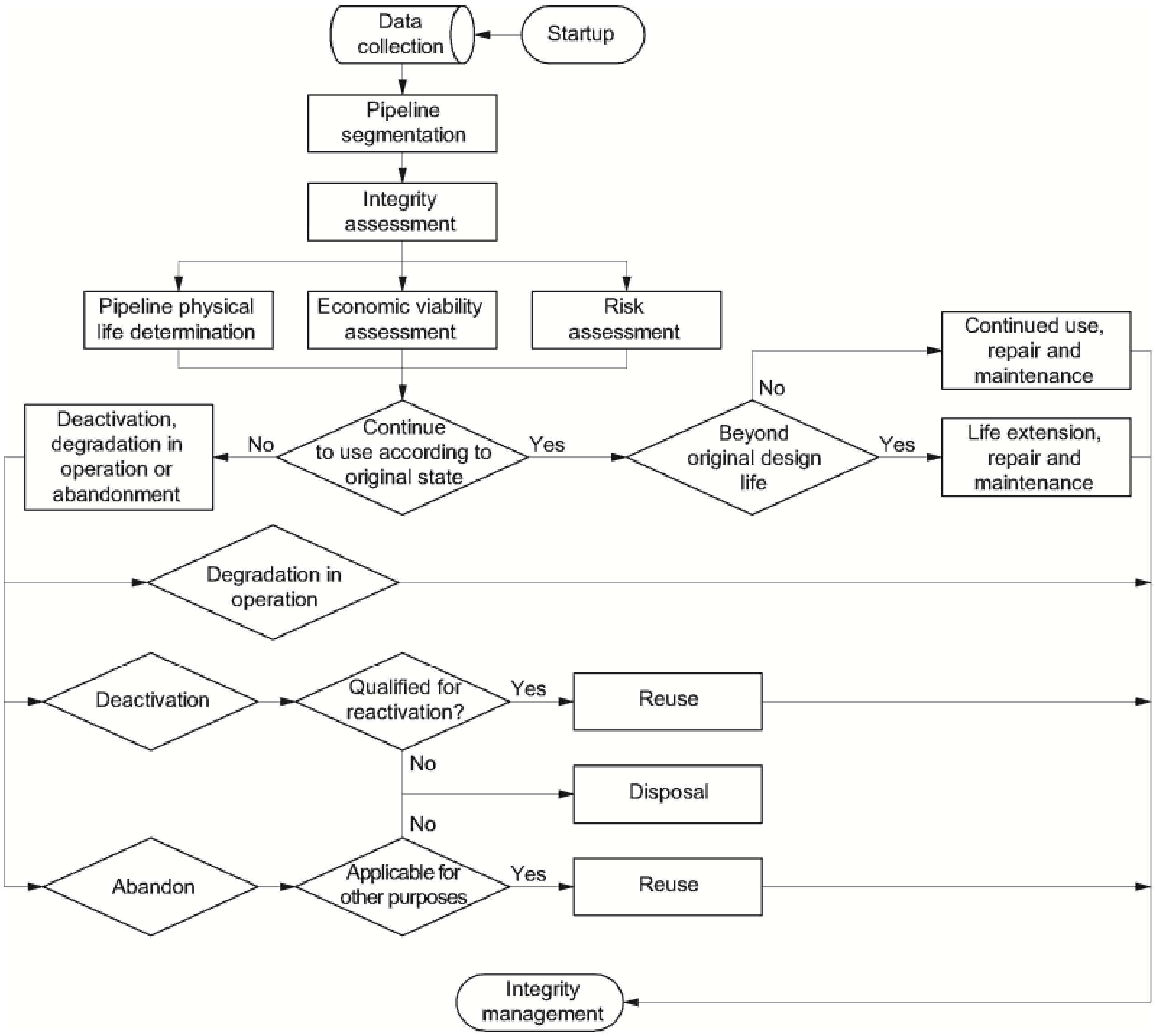


Figure 6 — Processes of pipeline remaining life assessment

13.2.2 Data collection

The following data is required for a pipeline life assessment:

a) design: grade of steel pipes, type of steel pipes, performance index, wall thickness, pipe diameter, design pressure, CP system information and coating information; initial design standard and specification, including version number and date of publishing;

b) product properties: physical and chemical properties, including density, viscosity, solidifying point, wax content, components, impurities, watercut, etc.;

c) manufacture and installation: industrial welding methods and processes, mode of pipe laying, field welding methods and processes, buried depth, field non-destructive test;

d) commissioning: commissioning and bulge testing records;

e) operating data: historical records of pressure, flow and temperature; historical records of corrosion detection, leak detection, safety forewarning system, corrosion monitoring and record of use of chemicals;

f) in-line inspection, direct assessment results and CP surveys information: inspection method, inspection frequency, inspection results, such as size and distribution of corrosion, welding defect, crack or coating defects, stress or strain, etc.;

g) integrity assessment results: historical records of pressure bearing capacity of all types of defects, number of unacceptable defects, repair and maintenance suggestions, suggestions for re-inspection intervals;

h) failure statistics and analysis: mode, causes, likelihood or consequence of failure, hydro-blasting experimental results, analytical results of the true failure of steel pipes;

i) historical records of repair: overhaul records of coating, repair method and time for all types of defects;

j) historical records of settlement inspection, crossing inspection and other third party events;

k) CCAs identification results;

l) risk assessment results: CCAs segment information;

m) historical finance data: transportation revenue, transportation cost, the original value of the fixed asset and the increasing value for the pipeline system, the original value of the pipeline, the newly increased value of the pipeline (fixed assets counted in route section due to overhaul, updating or renovation), pipeline maintenance cost (route maintenance cost, wax clearing fee and pipeline cleaning fee, patrolling fee, flood protection fee, barrier removal fee and safety protection fee);

n) add in costs of abandonment/decommissioning efforts.

NOTE 1 The above data is not all-inclusive list; other data sets can be required as determined by the operator's integrity management practices.

NOTE 2 It is recommended to use the most recent verified data in order to ensure accuracy of resultant analysis data as used in reporting and data sharing.

13.2.3 Pipeline segmentation

For a long-distance liquid and gas transportation pipelines, individual pipeline segments can have a distinct difference on the likelihood of failure and consequence because of the differences in manufacture, installation and surrounding environmental factors upon the risk evaluation. Therefore, the operator shall segment and assess the pipeline segment according to logical factors. Pipeline segmentation shall be implemented based on the varied operating condition, failure history, unacceptable defect density, material performance, and operation pressure, pipeline running time and risk assessment results. For industrial applicability, the pipeline can be divided into number of segments based on the station length.

13.2.4 Integrity assessment

Any integrity assessment shall follow the practices as stated in Clause 8. The operator should consider primarily using an ILI-based integrity assessment method. Direct assessment and hydro-testing can be used as an alternative, but also additional assessment methods shall be considered, such as:

a) review of the historical operation records;

b) detailed assessment of the integrity of the pipeline system;

c) failure mode and cause analysis;

d) analysis and testing of steel pipe and welding quality;

e) change of pipeline process;

f) recommendations for safe operation and management.

13.2.5 Physical life assessment

13.2.5.1 Key index method

After the assessment of pipeline integrity conditions, a key index method should be adopted to determine pipeline physical life, where other appropriate assessment methods can also be used and where technical conditions and data availability permits.

The key index method, which is based on inspection and assessment data, uses key factors that affect the life of a certain pipeline through subject matter expert review and assessment. This method aims to confirm pipeline integrity by such key factors and to determine pipeline availability and in-service risks.

Specifying a key technical index is a requirement in assessing pipeline physical life, and includes the following:

a) Unacceptable density of defects (defect distribution should also be considered).

b) Unacceptable defect density in identified critical consequence areas.

c) Reparability of unacceptable defects: Consideration should be given to the repair method and timeliness of repairs, the repair workload and economic justification of repair, e.g. in case that the cost of a repair period exceeds the alternative costs for a time period of pipeline operation. The likelihood of failure after any repair measures should be reduced so that risk of failure is at an acceptable level. Where repairs are not permitted, unacceptable defects shall be considered irreparable and mitigation of risk requires other measures. Comparisons of cost in different time periods should account for the time value of capital expenditure.

d) Whether pipe materials and performance of welds (parent metals and strength, plasticity or ductility of welds) meet relevant standards.

e) Whether pipelines have time-related defects that cannot be maintained or repaired and are found to introduce a greater likelihood of failure.

f) Pipelines are unsuitable for conventional inspection (e.g. serious wax deposit or insufficient flow) that cannot be maintained or repaired and are found to have a greater likelihood of failure.

g) Assessment results for changes in pipeline operational process conditions (transportation temperature and medium, etc.) indicate that the pipeline cannot satisfy safe operation requirements and there is greater likelihood of failure.

h) Ineffective corrosion resistance (aging coating, ineffective CP) of pipelines; such as extreme conditions for overall failure of pipeline coatings.

i) Likelihood of failure of all segments within the pipeline: In the case that the likelihood of failure exceeds the acceptable risk level and recent likelihood of failure increases abruptly, the situation will be considered unacceptable.

j) Conformity of the operation and integrity of transportation pipelines to relevant pipeline laws, regulations and standards.

k) Whether demands of transportation of liquid and gas resources match the pipeline's practical transportation capacity.

If one or more of above technical indexes cannot satisfy requirements for safe pipeline operation, the operator shall consider abandonment of the pipeline. If the operator can prove pipeline integrity with sufficient evidence, the pipeline may not need to be abandoned and operations may continue.

With a corrosion growth rate model, crack growth propagation model and other related methods, defect growth and its impact on pipeline integrity for future years can be predicted. By the analysis and application of such data, the conformity of a pipeline to specified technical indexes in coming years can also be preliminarily confirmed, in order to facilitate decisions and actions regarding pipeline abandonment.

This document suggests the use of calculations of likelihood of failure that are based on reliability of inspection data where technical conditions and data permit. Such calculations will help determine the likelihood of pipeline failure in different and specific times in the future and compare it with the maximum allowable likelihood, in order to define the physical life of the pipeline. After pipeline re-inspection, a physical life assessment should be performed again. This physical life assessment should account for uncertainty in the inspection (e.g. ILI defect sizing or probability of detection) data as well as uncertainty in service condition.

All records of integrity assessment, physical life assessment, economic assessment and decisions on pipeline operation shall be captured as data within the data management of the pipeline integrity management system.

13.2.5.2 Factorization method (analogy method)

For pipelines unsuitable for in-line inspection, pressure test or other related direct integrity assessment methods, their physical life can be estimated by reference to results of life assessment as determined for other comparative pipelines (if available). This approach is called the factorization method (analogy method) where pipeline physical life estimation can be derived from the Formula 4.

$$PPL=PPL_R\,[a, b, c, d, e, f, g] \qquad (4)$$

where

PPL is pipeline physical life;

PPL_R is pipeline physical life for reference;

Factor a is pipe-making level;

Factor b is design level;

Factor c is construction level;

Factor d is ambient impact of external pipe (coating, CP, land subsidence, etc.);

Factor e is impact of liquid (gas) quality inside pipelines;

Factor f is operating conditions (in-service life, pressure, temperature, etc.);

Factor g is repair and maintenance.

The relative weighting of multiple factors as a whole will exert a significant influence on the overall results as factor are based on previous cases for other pipelines. Therefore, an overall consideration of the relative weightings should be included when implementing the factorization method as factors can e added or adjusted accordingly in estimating the specific pipeline system as practical conditions can vary.

The factorization estimation result should be validated by correlation with other physical life assessment data of other pipelines wherever possible.

13.2.6 Economic viability assessment

13.2.6.1 Economic comparison

This document describes the economic comparison of schemes, including the minimum annual average cost method and cost-benefit analysis method for assessing economic viability. Other appropriate assessments can also be applied wherever technical conditions and data permit. If pipelines do not have any, or insufficient liquid or gas supply, and cannot meet minimum requirements for pipeline transportation, then that result should be considered at the end of the original design life or earlier, particularly if transportation costs of operating the pipeline are higher than those of alternative methods, such as railway and ocean transportation.

Economic comparison includes:

a) comparison between life extension of existing pipelines and new replacement;

b) comparison of different transportation modes in low transportation quantity.

Compared to existing, and particularly older pipelines, newly-constructed pipelines will be more technologically-advanced and scientifically-designed to run more safely and efficiently. Replacement of a pipeline will reduce operating risks and maintenance costs, however will require a significant amount of capital investment. In terms of the optimal time to replace a pipeline, consideration should be given to the likelihood that an abandoned pipeline will produce substantial resource waste.

In the economic evaluation of the viability of an existing pipeline, the cost comparison should be based upon total costs for the existing pipeline against the minimum annual average cost of a newly-built replacement pipeline. The decision to continue or replace the pipeline will be according to the minimum principle of annual cost.

In the case of a higher operating load, unit transportation cost of pipelines is economical relative to other transportation modes (road, railway, and ocean). However for low carrying capacity, economical efficiency should be measured for alternative transportation modes to identify the one with minimum unit transportation cost.

13.2.6.2 Minimum annual average cost method

Regardless of revenues derived from the operating pipeline, the minimum annual average method judges the pipeline economic viability merely from the operating costs. This method is applicable for circumstances that have guaranteed upstream resources, thus a stable throughput for the pipeline and sets safe, reliable production as the top priority of the operation.

The time period set for an annual average total cost (at lowest level) of pipeline operation is the economical viability. The annual average total cost, inclusive of annual average asset recovery cost and annual average operating cost, also then considers time value of capital expenditure.

After obtaining actual cost data in operation, historical trends in costs during pipeline operation should be analyzed to predict operating costs in years to come. Economic viability of a pipeline is determined by observing variation of average total cost. Consecutive years during which average total cost fluctuates below 5 % before and after the end of a pipeline's economic viability are called economic viability region.

13.2.6.3 Cost-benefit method

Relative to pipeline income, costs arise from pipeline operation and are applicable for circumstances under which upstream resources for the throughput of the pipeline is not stable and business objectives include criteria for profit or profit maximization.

Based on bearing capacity and preference of the operator, this method outlines referenced economic viability for pipelines.

13.2.7 Risk assessment

Risks related to pipeline operations are key indexes (see Clause 6 for detailed methods) in the decisions regarding pipeline service life. Risks considered shall include consequence factors of safety, business disruption in current and future operations and therefore constitute an important part of the life assessment.

The operator should establish specific standards for allowable risks that meet its operating requirements. ISO 16708 provides guidelines in risk acceptability and target likelihood of failure.

13.2.8 Remaining life assessment

According to the assessment results in previous subclauses, decisions of pipeline can be continuing to use, degradation in operation, deactivation and abandonment. If the pipeline is still under service, integrity management shall be applied; otherwise it shall be appropriately disposed.

13.3 Deactivation and abandonment process

13.3.1 Guideline for the abandonment of a transportation pipeline

If it has been determined, by remaining life assessment, that a pipeline should be abandoned, the operator shall undergo steps of deactivation (decommissioning) and then abandonment.

Before abandonment activities, field assessments, risk assessments and targeted risk mitigation measures should be performed to ensure that risks of pipeline abandonment are known and manageable. Use of comparative assessment process in order to assess the relative benefits versus drawbacks of decommissioning options should be considered.

Abandonment of pipeline facilities shall include safe disconnection from an operating pipeline system, purging of combustibles and hazardous materials, and the sealing of the abandoned facilities left in place to minimize safety and environmental hazards.

Once a pipeline is abandoned, it will not be used for transporting liquid and gas and should be physically isolated from the liquid and gas transportation system network.

Cleaning activities should be performed immediately when the pipeline is deactivated. Safety and environmental risks incurred by abandoned pipelines should be thoroughly eliminated to a known and predetermined acceptable level.

Abandonment has two forms:

a) abandonment in place;

b) pipeline removal.

In cases of abandonment for pipes that cannot be removed, including crossing of large and medium-sized rivers, swamps, lakes, water resources, railway, highway, natural reserve, densely populated area, forest cover area, wildlife habitat, restricted area, places occupied with buildings or deeply embedded (depth ≥ 4 m) with pipes, such pipes can be abandoned in place.

For abandonment in place, the operator should consider filling the abandoned pipeline with a permanent inert substance (e.g. filling mud, cement paste or cement mortar, etc.), and such pipe lines should be capped, plugged, or otherwise effectively sealed.

For any large-scale abandonment project, it is unlikely that only one of these options will be employed; rather, a project will usually involve a combination of pipe removal and abandonment-in-place along the length of the pipeline.

13.3.2 Preparation before pipeline abandonment

Before undertaking pipeline abandonment, the operator shall organize qualified personnel to prepare the pipeline abandonment plan and entrust qualified environmental evaluation and safety evaluation personnel to perform the related envrionment and safety evaluation. This plan is required to analyze safety and environmental risks in each disposal link and to supply relevant control measures, ensuring that entire pipeline abandonment and disposal processes are under control and environmental protection conforms to national and local requirements. If there is no transported liquid medium disposed on site during abandonment, assessment of medium impact on environment and safety assessment will be unneccessary. If excavation is not conducted, assessement of excavation impact on environment and safety assessment will be unneccessary.

13.3.3 Pipeline cleaning

Cleaning shall be conducted if necessary before abandonment. All pipeline cleaning activities shall be conducted with foremost environmental protection, including the recovery, recycling, separation, measuring, transportation and storage of removed liquid and gas.

For the cleaning of liquid pipelines that are to be abandoned, the operator shall purge pipelines of liquid products including low solidifying point crude liquid by nitrogen.

Each gas transportation pipeline that is to be abandoned in place shall be disconnected from all sources and supplies of gas, and subsequently purged of the gas and any hydrocarbons. Gas pipelines should be purged with nitrogen.

13.3.4 Deactivation of piping

To reuse the pipe in the future, some pipelines should be deactivated. The deactivation of pipelines involves depressurization and isolation of the segment from the main transportation pipeline network. The operator shall isolate the pipe using blind flanges, weld caps, or blinding plates and where required, provide a pressure-relief system.

The operator shall fill the piping with a suitable medium, having regard for the intended duration of the deactivation, the effects of the medium on the integrity of the piping, and the potential consequences of a failure. For instance, water carrying corrosion inhibitor or low-pressure nitrogen or other proper inert gas can be used for filling. When sealing, pressure of inert gas inside pipelines should be limited to 0,02 MPa to 0,04 MPa.

Upon completion of pipeline sealing, further in-service pipeline management measures should be made to eliminate any further risk. Such measures shall include, but are not limited to the following:

a) maintain external and internal corrosion control;

b) maintain records;

c) where considered appropriate, perform other maintenance activities.

For pipelines that have been deactivated, the operator shall annually confirm the suitability of the deactivation methods used, the corrosion control, and other maintenance activities to ensure the integrity of the pipeline to its expected deactivated state.

13.3.5 Permanent disposal process of abandoned pipeline

For pipelines segments identified for pipe removal, the pipe should be cut, removed, transported, stored and disposed of, by strictly following the abandonment and removal plan for the pipeline.

All relevant safety and environmental control measures shall be taken to avoid any safety or contamination accidents.

Backfilling and land recovery should take place in a timely manner after pipelines are removed.

For pipe segments that are considered unmovable, the operator shall fill the abandoned pipeline with an inert substance according to the established abandonment plan (e.g. filling mud, cement paste or cement mortar, etc.) and such pipes should be capped, plugged, or otherwise effectively sealed.

In cases that the ownership of abandoned pipelines will be transferred to a local government or other companies, all information about the current pipeline and intra-pipeline mediums shall be provided including information and plans regarding potential risks determined for removal.

Active management and patrol protection is not required for abandoned pipelines that have been permanently disposed. The operator should maintain records of the pipeline and the abandonment process as outlined in 13.3.6.

13.3.6 Records

13.3.6.1 Records shall be maintained of all pipes that have been abandoned in place. Such records shall include locations and lengths for each pipe diameter and, where practical, burial depth. The operator should maintain all pertinent records related to the abandoned piping.

13.3.6.2 Upon the completion of the abandonment process of the pipeline, the operator shall deliver relevant documents of the abandoned and disposed pipelines including the location, length, burial depth, disposal measures, environmental control measures and land recovery, to relevant stakeholder groups (e.g. local government agencies) and archival departments within the operator's organization including related communications to local government agencies.

13.3.6.3 Management of change processes (see Clause 16) should be performed for the pipeline abandonment and deactivation.

13.4 Life extension and recycle of pipeline

13.4.1 Life extension

Where it is intended to operate a pipeline beyond its original design life, a life extension assessment shall be completed that describes steps required to continue operation of the pipeline such that it will not produce any unacceptable risks after life extension. A life extension assessment shall include integrity assessments of current and future states of the pipeline and recommended remedial activities required.

If life extension of a pipeline is concluded to be unreasonable or impractical (such as in comparison to a new pipeline as a cost-optimal solution), the pipeline should be planned to be operated and then decommissioned upon the end of its design life.

The operator shall document and record the life extension assessment.

Life extension processes include the integrity assessment of the current pipeline and assessment of life extension applicability. Such an assessment shall consider circumstances that have been documented in routine operation, but were not considered in the original design of the pipeline.

The allowable life extension period shall be decided within the life extension assessment including results from the related integrity assessment of the pipeline. If the operator's planned life for the pipeline system exceeds the remaining life identified in the integrity assessment, further remedial measures shall be considered to reassess the remaining life of pipeline system.

Such remedial measures may include:

a) replacement of pipe fittings;

b) reassessment of limit values of anomalies and correction of anomalies;

c) reassessment of pipeline degradation while still in operation.

Assessment can be referred to 13.2 and ISO/TS 12747 for detailed methods of life extension.

13.4.2 Recycle of pipeline

13.4.2.1 Reactivation of pipeline

The operator may reuse a pipeline which has been previously deactivated. Prior to reactivating the pipeline, the operator shall conduct an engineering assessment to determine whether the pipeline would be suitable for its intended service. Where the engineering assessment indicates that the pipeline would not be suitable for its intended service, the operator shall implement measures necessary to make it suitable before reactivating the pipeline.

13.4.2.2 Recycle of abandoned pipelines

Abandoned pipelines can be considered for other purposes if permanent disposal methods were not undertaken. Such purposes can include storage for other industrial wastes, rebuilt as drainage facilities, shallow well casing, civil facilities or onshore exploration of shallow wells.

13.5 Uprating

13.5.1 General requirements

The evaluation of a pipeline for service can also include an assessment for operation of the pipeline at a higher capacity than current operations, as motivated by investments into significant modifications to the pipeline changes in service.

If the operator intends to uprate its pipelines, it shall establish a written plan that includes all associated works and complete management of change for pipeline uprating. All records of the plan shall be maintained by the operator.

The operator shall conduct an engineering assessment to determine suitability of the pipeline for service at the proposed higher pressure.

13.5.2 Limitation on increase in maximum allowable operating pressure

The proposed MAOP shall not exceed the maximum that would be allowed under local law, regulation or standard for a new segment of pipeline constructed of the same materials in the same location.

13.5.3 Uprating method

Before increasing the operating pressure of the pipeline above the previously established MAOP, the operator shall apply the following steps as a minimum:

a) Review the design, operating and maintenance history, and previous testing of the segment of pipeline to determine whether the proposed increase is safe and consistent with the new operating condition.

b) Make any repairs, replacements, or alterations necessary to be compatible (safe) with the new operating level.

c) Adequately reinforce or anchor any offsets, bends, and dead ends in coupled pipe to prevent movement of the pipe if the offsets, bends, or dead ends become exposed in excavation.

d) Review the class location change in pipeline right-of-way and determine that the proposed increase is safe and consistent with new requirements of regulations and laws.

e) Repair any failure detected before a further pressure increase is made.

f) If the pipeline materials can be identified through a material test and the design calculations for the pipeline would be the same as those for a new pipeline in the same area, a hydrostatic test may be completed to establish a new MAOP.

g) If a hydrostatic test is identified in the written plan as the method for uprating the pipeline, the test of the pipeline segment should be performed in accordance with 8.3 and local regulations for hydrostatic testing of pipelines.

   For steel pipe operated at 0,7 MPa [7 bar(g)] or more, the test pressure shall be calculated by multiplying by a safety factor. Unless a regulator provides a safety factor, Table 7 provides some guidance.

h) If the new MAOP will be established by sequentially increasing the pressure in the pipeline, then the following shall be considered:

   1) Any increases in pressure shall be made in increments, where the pressure shall be increased gradually, at a rate that can be controlled. At the end of each incremental increase, the pressure shall be held constant while the entire segment of pipeline that is affected is checked for leaks.

   2) The new MAOP does not exceed 70 % of that allowed for a new line in the same location and the same design.

Table 7 — Suggested safety factor of proposed increase pipeline

CCAs Rank	Factor
I	1,1
II	1,25
III	1,4

The operator shall guarantee that the new MAOP is consistent with the conditions of the segment of pipeline and the design requirement.

The incremental increases in pressure shall be made equal to:

a) 10 percent of the pressure before the uprating; or

b) 25 percent of the total pressure increase,

whichever produces the fewer number of increments.

13.6 Reporting

The operator shall prepare and maintain a detailed report which summarizes the works related to life assessment and life extension assessment. This report shall include the following as a minimum:

a) general description of the pipeline and pipeline life assessment procedure;

b) main results of the pipeline integrity assessment;

c) main conclusions to the risk assessment;

d) nonconforming items identified relating to current applicable laws, regulations and standards;

e) conformity of previous design, pipe making, construction and other specifications to current relevant specifications;

f) main conclusions of the economic life assessment;

g) main conclusions of the physical life assessment;

h) statement and basis of the remaining life estimated from the above assessments (both as safe and economical operating viability).

14. Records and documents management

14.1 The operator shall establish plans for the classification, identification, collection, storage and disposal of records and documents pertinent to:

a) historical information required for the safe operation and maintenance of the pipeline over the pipeline's life;

b) objective evidence of pipeline management system effectiveness and compliance;

c) records and documents of decision-making and approvals.

Procedures shall cover electronic and paper-based records and documents. Classification included documents considered confidential or non-confidential.

14.2 The operator shall prepare and manage records and documents related to pipeline design, construction, commissioning, operation, maintenance and abandonment that are needed for performing the activities included in the pipeline IMP. The following items shall be included as a minimum:

a) Design, construction and commissioning details, such as:

   1) design basis, including design calculations;

   2) material specifications and certification;

   3) inspection and test certification and reports;

   4) documents relating to authorizations and permits to operate;

   5) surveys and route documentation;

   6) land ownership details;

   7) pressure testing summary;

   8) any adjustments, events and non-conformances during each phase.

b) Operation and maintenance details, such as:

   1) historical pipeline management system plans and procedures;

2) any change to operating conditions;

3) any modification to the maps, charts, plans, drawings and procedures, required to allow the procedures to be properly administered;

4) details of any corrosion, dents or other anomalies;

5) details of the CP system;

6) failure records, analysis and subsequent preventative actions;

7) details of inspections, and inspections and testing carried out when cutting a pipeline or making hot taps;

8) repairs and modifications;

9) pipeline surveillance patrol reports;

10) emergency response and exercises records;

11) personnel training and qualification records;

12) reports on landowners and third-parties.

c) Abandonment details.

The operator shall document the archiving or disposal of records associated with an abandoned pipeline. A record shall be kept of all abandoned pipelines that remain *in situ*, to prevent possible mistakes in identifying an abandoned pipeline as an operational pipeline. Where CP is applied, to prevent the corrosion of the pipeline, the responsibility for maintenance of the system shall remain with the operator and appropriate records shall be kept.

15. Communication

15.1 General

The operator shall develop and implement a communications plan in order to keep appropriate personnel, jurisdictional authorities, and the public informed about its integrity management efforts and the results of its integrity management activities. Information can be communicated routinely or upon request. Use of industry, jurisdictional, and company websites can be an effective way to conduct these communication efforts.

15.2 External communications

The following items shall be considered as a minimum for communication to the various interested parties, as outlined below:

a) Landowners and tenants along the rights-of-way:

1) company contact information;

2) depth of cover;

3) general location information and more specific information or maps where such details can be obtained;

4) commodity transported;

5) how to recognize, report, and respond to a leak;

6) general information about the operator's prevention, integrity measures, and emergency preparedness.

b) Public officials other than emergency responders:

1) periodic distribution to each municipality of maps and company contact information;

2) summary of emergency preparedness and IMP.

c) Local and regional emergency responders:

1) continuing liaison with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.;

2) company contact information, both routine and emergency;

3) local maps;

4) facility description and commodity transported;

5) how to recognize, report, and respond to a leak;

6) general information about the operator's prevention and integrity measures, and how to obtain a summary of the IMP;

7) station locations and descriptions;

8) summary of operator's emergency capabilities;

9) coordination of operator's emergency preparedness with local officials.

d) General public:

1) information regarding operator's efforts to support excavation notification and other damage prevention initiatives;

2) company name, contact, and emergency reporting information.

e) Other stakeholders:

information regarding integrity management efforts and the results

15.3 Internal communications

15.3.1 The operator manager and other appropriate operator personnel shall understand and support the IMP. This shall be accomplished through the development and implementation of an internal communications plan. Performance measures reviewed on a periodic basis and resulting adjustments to the IMP shall be part of the internal communications plan.

15.3.2 The following items shall be considered as a minimum for communication to the various related departments:

a) key components of the integrity management framework, and any subsequent modifications;

b) adequate internal reporting, its effectiveness and the outcomes;

c) relevant information derived from the application of integrity management available at appropriate levels and times.

16. Management of change

16.1 Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. Management of change shall address operational, technical, physical, procedural, and organizational changes to the system, whether permanent or temporary.

16.2 A management of change process shall include at a minimum the following:

a) reason for change;

b) authority for approving changes;

c) effective date for change to occur;

d) analysis of implications of the change;

e) documentation, drawings, and records updating communication of change to affected parties.

16.3 Impact and risk of changes should be adequately identified and communicated internally and externally.

16.4 Changes shall be managed through the full life of the pipeline, including design, construction, operation, maintenance and abandonment. Any new results derived from the integrity management efforts and the subsequent amendments should be effectively updated in the system and managed as changes.

16.5 As for process change, pipeline route modification and repair, re-evaluation of critical consequence areas and risk shall be accomplished and the IMP shall be modified.

17. Training and competency

17.1 General

It is recognized that different jurisdictions require a minimum qualification of education or competency, such as an engineering degree to perform pipeline engineering work. This clause establishes the complementary skill and training requirements for personnel who perform pipeline integrity management. It also specifies the required qualification and certification for pipeline integrity management staff involved in liquid and gas transportation pipelines.

The qualification training and certification management of pipeline integrity management is a stratified system. When qualified individuals achieve a higher level of qualification and/or certification, training and qualification for previous levels remain valid unless otherwise stated as part of the high level certification. Individuals at each level of qualification are allowed to perform appropriate works as stated under that qualification.

The operator should prepare and fully implement written plans, including specifications of training and qualifications of integrity management personnel. The operator should review training plans of personnel at least annually and revise its plans from time to time as necessary. The operator shall review its training plans to ensure effectiveness and qualification of personnel, such as for new equipment and as new techniques or management concepts are introduced within its organization. The training plans should be revised or updated accordingly.

17.2 Levels of qualification

17.2.1 Levels of trainees

The qualification training and certification management can be divided into three levels:

— level 1: preliminary level;

— level 2: intermediary level;

— level 3: senior level.

Based on the intended scope of work, individuals shall have sufficient qualification of pipeline integrity management to a level required for the works that they are intended to perform. Otherwise the designated individuals should undertake the appropriate training required to achieve the appropriate level. Only individuals who obtain qualifications above level 1 can do works of CCA identification and data acquisition. Individuals who get qualifications above level 2 can do threat identification and risk assessment. Individuals who obtain qualifications of level 3 can do works of integrity assessment, comprehensive risk assessment and performance measurement.

The operator can arrange for certification to provide training and accreditation of employees or use third parties to provide training and certification.

17.2.2 Requirements for trainers

17.2.2.1 General trainers

A general trainer should meet one of the following requirements:

a) having more than five years of pipeline integrity work experience and being well-known in integrity management field and his/her contributions are widely used in projects with competent for training;

b) having established an industrial standard or having participated substantially in writing national standards;

c) having more than three years of training experience in an organization recognized throughout the world for training in integrity management.

17.2.2.2 High-level trainers

A high-level trainer should meet one of the following requirements:

a) having more than ten years of integrity work experience and related technical background and being well-known in the pipeline integrity field worldwide and his/her contributions are widely used in projects;

b) having established national standards or international standards or having published an integrity monograph in English;

c) having more than five years of training experience in an organization recognized throughout the world for training in integrity management.

A high-level trainer being accredited as level 3 may train those of level 1 and level 2.

17.3 Training

17.3.1 Training objectives

Integrity management training aims to implement a consecutive training program designed to assist integrity management personnel in obtaining their required qualifications to perform their work-related operating duties and processes.

17.3.2 Training approach

Training should be offered by training organizations with extensive pipeline integrity experience and should be taught in practical work environment on site. Lecture rooms, computers, tape-recording and other methods can be applied, aiding job training when necessary.

17.3.3 Training program

Integrity management personnel should acquire professional skills within six pipeline areas. This training may vary in the training programs and examination contents in accordance with the different levels of management qualifications. Annex I includes an example of training courses for level 1, 2 and 3, the management qualifications and related professional requirements, in the following fields:

a) comprehensive integrity management;

b) data management;

c) risk assessment and CCAs identification;

d) pipeline inspection and fitness for purpose assessment;

e) pipeline defect repair;

f) pipeline maintenance.

17.4 Examination and qualification verification

Trainees of Level 1 and Level 2 who have mastered theoretical knowledge and possess practical operating ability shall take appropriate examinations and qualification verification according to this document. Trainees capable of demonstrating they have obtained sufficient knowledge and skills and competence to conduct the required operations of relevant jobs will be accredited as qualified pipeline personnel. Such training courses and examinations can be in written, computer-based or oral forms.

Trainees of Level 3 are required to provide evidence of at least two independently performed projects or research theses formally published in relevant fields. They also shall pass an interview organized by associated professional technical experts before applying for qualification accreditation.

17.5 Examination management

The operator shall maintain training and qualification records on integrity management personnel. Such forms of records may include: evidence of training and certification, record of training and changes to higher levels of certification or specialization.

17.6 Training and re-accreditations

17.6.1 When new regulations, equipment, techniques and procedures, or new management concepts are adopted into a pipeline operating company, and relate to work responsibilities of pipeline integrity management, the relevant personnel shall be re-trained and re-accredited for their qualifications.

17.6.2 After obtaining qualifications, integrity management personnel should receive training at least once for every three years to update their knowledge and skills about their positions.

Annex A
(informative)
Example approach of semi-quantitative risk assessment

An example of semi-quantitative risk assessment is provided in Table A.1. The failure likelihood is the sum value of third party damage, internal corrosion, external corrosion, manufacture defect, construction defect and geologic hazard. The failure likelihood multiplied the failure consequence to get the risk. The operator should decide the weighting value of each category

Table A.1 — Example of semi-quantitative risk assessment

Category	Factors	Value
Third party damage	Cover	0~100
	Patrol	
	Public education	
	Right-of-way condition	
	Theft/sabotage	
	Activity level	
	Locating and response	
	Above ground facilities	
	Vehicles	
	Government's attitude	
Internal corrosion	Product corrosivity	0~50
	Internal protection	
External corrosion	Soil corrosivity	0~50
	Cathodic protection effectiveness	
	Cathodic protection test	
	Other electrical interference	
	Coating condition	
	External inspection and repair	
	In-line inspection and repair	
Manufacture defect and construction defect	Internal inspection	0~100
	SMYS	
	Safety factors	
	Fatigue	
	Surge potential	
	Hydro-testing	
	Seam weld type	
	Pressure	
Geologic hazard	Topography	0~100
	Geotech	
	Hydrotech	
	Pipeline design	

	Mitigative structures	
Incorrect operations	Threat identity	0~100
	Safety system	
	Procedures	
	Training	
	Documentation	
Failure consequence	Product threat	0~10
	Leak volume	
	Emergency response	
	Population density	
	Environment	
	Cost	

Annex B
(informative)
Risk matrix

The risk matrix should be defined including failure probability rank, failure consequence rank and risk categories. The failure probability should preferably be defined as per Table B.1. Assessment of failure consequences should take the safety, cost, environment, service interruption and reputation into consideration, as shown in Table B.2. An example of a risk matrix is shown in Table B.3 whereas the risk categories are defined in Table B.4. The operator can modify or determine its own category criteria and applicable values.

Table B.1 — Failure probability rank

Probability description		Rank
Probability	**Description**	
Very high	Failure has occurred in location; or Failure is expected in 1 year	5
High	Failure has occurred several times a year in operating company; or Failure is expected in 1~3 years	4
Medium	Failure has occurred in operating company; or Failure is expected in 3~5 years	3
Low	Failure has occurred in the industry; or Failure is expected in 5~10 years	2
Very low	Failure has not occurred in industry; or Failure is expected >10 years	1

Table B.2 — Failure consequence rank

Consequence categories	Increasing consequence				
	A	**B**	**C**	**D**	**E**
Safety	None or superficial injuries	Major injury, long term absence	1~2 Fatalities	3~9 Fatalities	>10 Fatalities
Cost (e.g. $M)	< 0,01	0,01 - 0,1	0,1 - 1	1 - 10	> 10
Environment	Insignificant	Slight/Minor effect	Local effect	Major effect	Massive effect
Service interruption	Insignificant	Major impact to service	Major impact to upstream/down stream company	Major national impact	Major international impact
Reputation	Insignificant	Local impact	Major regional impact	Major national impact	Major international impact

Table B.3 — Risk matrix

Consequence	Likelihood				
	1	2	3	4	5
E	III	III	IV	IV	IV
D	II	II	III	III	IV
C	II	II	II	III	III
B	I	I	I	II	III
A	I	I	I	II	III

Table B.4 — Risk category

Category	Description
I	Low
II	Moderate
III	High
IV	Very high

Annex C
(informative)
An example of the threat identification in lifecycle phases

Table C.1 provides an example of threat categorization, and associated causes of occurrence during each phase of the pipeline lifecycle. The structure of the table is such that it lists each of the life cycle phases and the potential threats for each lifecycle phase. These potential threats are to be categorized according to the nature of the threat, such as mechanical (intrinsic factors), environmental (extrinsic factors) and then further sub categorized to state the damage mechanism(s) and the initiating source of the threats. This process of categorization will aid in the management or mitigation of the threat either by taking specific actions to prevent the threat from materializing at the specific life cycle phase or by acknowledging the potential for the threat occurring and anticipating, managing and mitigating, or eliminating the threat during the service life of the pipeline. If the threats are not fully mitigated from occurring at a given lifecycle phase, then these threats should be anticipated and regular condition monitoring should be conducted to verify the absence or existence of the threat throughout the service life of the pipeline.

Table C.1 — Categorization of threats

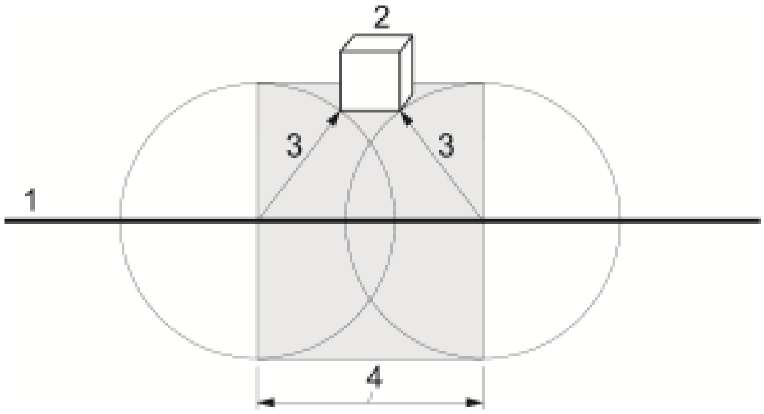
	Mechanical threats						**Environmental threats**		**Other threats**
Life cycle phase	**Mechanical damage**	**External corrosion related**	**Internal corrosion related**	**Incorrect operation**	**Weld flaws**	**Pipe body flaws**	**Weather related**	**Geologic hazard**	
1. Feasibility	Material selection Protect design	Material and coating selection CP system	Material/ internal coating	Appropriate safety factor	Material selection	Material selection Pipeline route soil properties Distance from compressor station	Material and coating selection Route selection	Route selection Material selection Strain based design seismic	
2. Design	Material selection Protect design	Material and coating selection CP system	Material/ internal coating	Appropriate Safety factor	Material selection	Material selection Pipeline route soil properties Distance from compressor station	Material and coating selection Route selection	Route selection Material selection Strain based design seismic	

3. Procurement	Material selection	Material and coating selection	Material/ internal coating		Material selection	Material selection	Material and coating selection	Material selection	
4. Fabrication	Protect design Quality control	Quality control	Quality control Caps (to avoid water)		Welding process (longitudinal/ spiral): deviation in automated process Quality control				
5. Transportation and storage	Protect design	Coating damage/ degradation Atmospheric corrosion	Coating damage/ degradation Caps (to avoid water) Atmospheric corrosion		Quality control?	Quality control?	Coating damage/ degradation		
6. Construction	Quality control, illegal offtake	Coating damage/ degradation Field coating application	Coating damage/ degradation Caps (to avoid water) Residual water	Incorrect procedure Procedure not implemented	Welding process (circular) Quality control		Temperature conditions (impact quality)	Construction process/ quality	
7. Pre-commissioning and commissioning		Coating cracks/ degradation	Residual water Compatibility of fluids Coating cracks	Over pressure Over temperature Incorrect product	Over pressure Over temperature	Over pressure Over temperature	Temperature conditions (impact quality)		
8. Handover	External damages, illegal offtake	Coating cracks/ degradation	Erosion	Over pressure Over temperature Incorrect product	Over pressure Over temperature	Over pressure Over temperature	Temperature conditions (impact quality)		
9. Operation and maintenance	External damages, illegal offtake	Coating cracks/ degradation/ peel CP system	Erosion MIC Products	Over pressure Over temperature Incorrec	CP effectiveness Pressure cycles	CP effectiveness Pressure cycles	Lightning Flooding Coating damage/ degradat	Soil stability Earthquake Urbanization	

		effective ness		t product			ion/ peel		
10. Modificati ons	Externa l damage s, illegal offtake	Coating cracks/ degradat ion/ peel CP system effective ness	Erosion MIC Products	Over pressure Over tempera ture Incorrec t product	CP effective ness Pressure cycles	CP effective ness Pressure cycles	Lightnin g Flooding Coating damage/ degradat ion/ peel	Soil stability earthqua ke Urbanizat ion	
11. Suspensio n/ abandon ment	Externa l damage s, illegal offtake	Coating cracks/ degradat ion/ peel CP system effective ness	Erosion MIC Products	N/A	N/A	N/A	Lightnin g Flooding Coating damage/ degradat ion/ peel	Soil stability Earthqua ke Urbanizat ion	

Annex D
(informative)
Determining CCA-affected segments

Figure D.1 gives a sketch map for determining CCA-affect segment.



Key

1	Pipeline	3	PIR
2	School	4	CCA

Figure D.1 — CCA-affect pipeline segment

Annex E
(informative)
Establishing performance measures

E.1 Classification of performance measures

Performance measures can be grouped into three classes: process/activity measures, operational measures, and direct integrity measures. Each class can be grouped into two categories: lagging measure and leading measure. An example is shown in Table E.1.

Table E.1— Examples of performance measurement by threat

Measurement category	Lagging measure	Leading measure
Process/activity measures	Pipe damage found per location excavated	Number of excavation notification requests, number of patrol notifications
Operational measures	Number of significant ILI corrosion anomalies	New rectifiers and ground beds installed, CP current demand change, reduced CIS fault notifications
Direct integrity measures	Pipeline failures per kilometre in an IMP	Change in pipeline failures per kilometre

E.2 Performance measures by integrity assessment process steps

The performance of the IMP should be measured in terms of the effectiveness of the elements of the program, namely the subjects of each section of this document as illustrated in Table E.2. As seen in Table E.2, each of the elements of an IMP is considered in terms of its effectiveness. For example, if any deficiency in the element resulted in an adverse impact to integrity or could have resulted in an adverse impact, a corrective action should be defined so that the performance of the element improves.

Table E.2—Performance measures by process step

Process element	Process measures	Integrity impact	Corrective action (if any)
Critical location selection	Did the extent of any release spread further than predicted?	One spill spread beyond limits defined by the model.	Reassess and improve the model for defining critical locations.
	Was the extent of any release larger than predicted?	Two spills were larger than predicted.	

E.3 Inspection audit form

Table E.3 provides a brief description of each item in an integrity management inspection audit form. The format and use of the form is recommended for any audits of IMPs such that the operator and the auditor can maintain clearly documented questions and answers within the audit processes and results.

Table E.3 — Example of an inspection audit form format

Protocol #	Keywords reflecting the subject area of the protocol question are entered here. Each question has a unique number, as indicated to the left.

<table>
<tr><td>Protocol question</td><td colspan="4">Question to be answered in reviewing an operator's IMP or the implementation of its program.
Questions in the integrity management inspection protocols generally cover two main aspects of an operator's program. The first part deals with the inspection of a particular aspect or feature of the operator's integrity management processes, procedures, technical methods, etc. The second part addresses how effectively the operator has implemented that process and the results that demonstrate the intended results have been obtained.</td></tr>
<tr><td colspan="5">This section contains additional guidance and items for consideration by the inspector in reviewing the operator's response to the protocol question. This guidance presents characteristics typically expected in an effective IMP consistent with the intent of the applicable regulations, practices and standards. Some, all, or none of these characteristics can be appropriate depending on potential factors unique to each protocol, and the operator's IMP and its pipeline assets. The operator should be able to demonstrate that its programs address each of these characteristics or should be able to describe how its program will be effective in their absence.
For some protocol questions, this portion of the inspection form is also used to articulate specific prescriptive requirements in the rule. These requirements are mandatory for all IMPs.</td></tr>
<tr><td>Rule requirement</td><td colspan="4">Reference to related rule requirement(s)</td></tr>
<tr><td>Inspection issues summary</td><td colspan="4">This space is provided to record any issues or concerns the inspector identifies in reviewing the operator's response to the protocol question.</td></tr>
<tr><td rowspan="3">Inspection results
The boxes to the right are checked based on the information supplied in the summary.</td><td></td><td colspan="3">No issues identified</td></tr>
<tr><td></td><td colspan="3">Potential issues identified (explain in summary)</td></tr>
<tr><td></td><td colspan="3">Not applicable (explain in summary)</td></tr>
<tr><td colspan="5">Documents reviewed: Documents reviewed in answering the protocol question are listed below.</td></tr>
<tr><td colspan="2">Document number</td><td>Rev.</td><td>Date</td><td>Document title</td></tr>
<tr><td colspan="2"></td><td></td><td></td><td></td></tr>
<tr><td colspan="2"></td><td></td><td></td><td></td></tr>
<tr><td colspan="2"></td><td></td><td></td><td></td></tr>
<tr><td colspan="5">NOTE This section is provided to record more detailed information about the operator's program obtained during the review of the operator's response to the protocol question. For protocol questions dealing with the implementation of a particular facet of an operator program, a summary of the records review is entered at this location.</td></tr>
</table>

Annex F
(informative)
Integrity data acquisition list

Pipeline integrity data should include all necessary data to identify the location of all equipment. Table F.1 indicates a range of additional data that would improve pipeline integrity management. Acquisition processes are also shown in Table F.1.

Table F.1 — Integrity data acquisition categories

No.	Category	Data types	Data acquisition source processes
1	Centreline	Centreline control points	Construction, operation
		Survey control points	Construction
		Depth of cover	Construction, operation
2	Cathodic protection	Cathodic protection records	Operation
		Cathodic protection potential	Operation
		Galvanic anode	Construction, operation
		Anode groundbed	Construction, operation
		Cathodic protection power	Construction, operation
		Drainage device for cathodic protection	Construction, operation
3	Pipeline facilities	Site boundary	Construction
		Pipeline marker	Construction, operation
		Buried sign	Construction, operation
		Appurtenance	Construction, operation
		Casing	Construction, operation
		Coating	Construction, operation
		Crossing	Construction, operation
		Bend	Construction, operation
		Receiver and launcher	Construction, operation
		Non weld connection	Construction, operation
		Steel pipe	Construction, operation
		Tap	Construction, operation
		Valve	Construction, operation
		Girth weld	Construction, operation
		Tee	Construction, operation
		Hydraulic protection	Construction, operation
		Tunnel	Construction, operation
4	Third party facilities	Foreign pipeline	Construction
		Utility	Construction, operation
		Underground obstacle	Construction, operation

5	Testing and maintenance	Internal inspection records	Operation
		External inspection records	Operation
		Pipe excavation inspection records	Operation
		Weld testing records	Construction
		Pressure testing	Construction
		Pipeline repair	Operation
6	Landbase	Structures	Construction, operation
		Rivers	Construction
		Land use	Construction
		Administrative division	Construction
		Railway	Construction
		Road	Construction
		Soil	Construction
		Geologic hazards	Construction, operation
		Oil and gas product	Operation
7	Operation	Failure records	Operation
		Operating pressure	Operation
		Patrolling records	Operation
		Line monitoring and warning system	Operation
		Cleaning tool running record	Construction
		Critical consequence area	Construction, operation
8	Pipeline risk	Pipeline risk assessment result	Construction, operation
		Geologic hazard evaluation result	Construction, operation
		Emergency organization	Construction, operation
9	Emergency management	Contact person	Construction, operation
		External emergency services	Construction, operation
		Emergency equipment information	Construction, operation
		Emergency organization personnel	Construction, operation
		Emergency plan	Construction, operation
		Emergency and repair records	Construction, operation
		Material reserve	Construction, operation
		Adjustments records	Construction, operation
10	Others	Training and qualification records	Operation
		Disposal documents	Abandonment

Annex G
(informative)
Structure of pipeline data tables

Tables G.1 to G.8 show the structure of pipeline data tables.

Table G.1 — Pipeline centreline location

Field name	Unit	Domain name	Description
Pipeline ID			Automatically numbered field; does not require input
Control point coordinate X	Degrees: minutes: seconds		
Control point coordinate Y	Degrees: minutes: seconds		
Depth of cover	m		
Elevation	m		
Remarks			

NOTE 1 The operator should assign unique name and ID for each pipeline.

NOTE 2 “Control point coordinates X” and “Control point coordinates Y” are latitude and longitude or projection coordinates. Specific projection information should be described in the “metadata table".

NOTE 3 “Depth of cover “ is the vertical distance between the surface of the earth and the top of the pipe.

NOTE 4 “Elevation” is the elevation of the earth’s surface.

Table G.2 — Pipeline centreline attribute

Field name	Unit	Domain name	Description
Pipeline operator ID			Automatically numbered field; does not require input
Pipeline operator name			
Pipeline ID			Automatically numbered field; does not require input
Pipeline name			
Pipeline length	m		
Product		Product type	
Commission date			
Design company name			
Construction company name			
Remarks			

NOTE 1 “Pipeline operator ID” is unique ID for the operator.

NOTE 2 ”Pipeline length” is the length of the pipeline, and the unit is meter, retained two decimal places.

NOTE 3 “Product” is the product of the pipeline transport system, and this field defines the domain value.

NOTE 4 Date is in the YYYYMMDD format.

Table G.3 — Pipeline segments attribute

Field name	Unit	Domain name	Description
Pipeline ID			Automatically numbered field; does not require input
Pipe segment ID			Automatically numbered field; does not require input
Segment length	m		
Diameter	mm		Nominal diameter of the pipeline segment, in meters (two decimal places, ##.##).
Thickness	mm		The thickness of the pipeline segment, in meters (two decimal places, ##.##).
Design pressure	MPa		
Operation status		Operation status	Identifies the current status of the pipeline segment.
Data quality		Data quality type	Operator's estimate of the positional accuracy of the submitted pipeline segment.
Foreign key attribute			Link between the geospatial elements(pipeline segments) and their respective attribute records
Update description		Update description	
Remarks			

NOTE 1 Pipe segment is a part of pipeline, and ID is assigned by the operator. A pipeline segment has only two ends. No branches are allowed. The number of pipeline segments should be kept to the minimum needed to represent a pipeline system and its associated attributes.

A pipeline system should be broken into multiple pipeline segments for only two reasons:

a) to represent a branch or intersection with another pipeline segment, and/or

b) to allow for a change of associated attributes such as diameter.

NOTE 2 “Data quality”:

a) excellent: within 1 m;

b) very good: 1 m – 10 m;

c) good: 10 m – 50 m;

d) poor: more than 50 m.

NOTE 3 “Update description” identifies this pipeline segment as:

a) addition pipeline;

b) spatial modification of the existing pipeline;

c) attribute modification of the existing pipeline;

d) both a spatial and attribute modification of the existing pipeline;

e) deletion of the existing pipeline;

f) no change to the existing pipeline.

Table G.4 — Contact table

Field name	Unit	Domain name	Description
Pipeline operator ID			Automatically numbered field; does not require input
Pipeline operator name			
p_name			Primary contact's name
p_title			Primary contact's title
p_companyname			Company name of the primary contact
p_address1			Primary contact's address, line 1
p_address2			Primary contact's address, line 2
p_zipcode			Primary contact's zipcode
p_workphone			Primary contact's work phone number
p_faxnumber			Primary contact's fax number
p_email			Primary contact's email address
t_name			Technical contact's first name
t_title			Technical contact's title
t_companyname			Company name of the technical contact
t_address1			Technical contact's address, line 1
t_address2			Technical contact's address, line 2
t_zipcode			Technical contact's zipcode
t_workphone			Technical contact's work phone number
t_faxnumber			Technical contact's fax number
t_email			Technical contact's email address
NOTE Public contacts responsible for handling the public about the related problem of the pipeline, a pipeline enterprise is allowed to have multiple contacts are responsible for different operating unit.			

Table G.5 — Site table

Field name	Unit	Domain name	Description
Pipeline operator ID			Automatically numbered field; does not require input

Pipeline ID			Automatically numbered field; does not require input
Site ID			Automatically numbered field; does not require input
Site name			
Site_city			The site's city
Site_province			The site's province
Projection		Projection type	
Datum		Datum type	
X			The coordinate X of the centre of the site district, retain three decimal places.
Y			The coordinate Y of the centre of the site district, retain three decimal places.
Measure unit		Measure unit	
Remarks			

Table G.6 — CCAs table

Field name	**Unit**	**Domain name**	**Description**
Pipeline ID			Automatically numbered field; does not require input
CCA No.			The CCA segment's number
District			
Begin station			
End station			
Begin marker			
Begin offset	m		
End marker			
End offset	m		
Length	m		The CCA segment's length
Type		CCA type	
Class area		Class area	
Analysis date			
Remarks			
NOTE Two kinds forms of CCA segments location: one is "begin station + end station", the other is "marker + offset".			

Table G.7 — High risk segment table

Field name	Unit	Domain name	Description
Pipeline ID			Automatically numbered field; does not require input
High risk segment No.			Automatically numbered field; does not require input
Begin station	m		
End station	m		
Begin marker			
Begin offset	m		
End marker			
End offset	m		
Threaten factor		Threaten factor type	
Assessment date			
Description			
Assessment company			
Remarks			
NOTE Two kinds forms of high risk segments location: one is “begin station + end station”, the other is “marker + offset”.			

Table G.8 — Metadata table

Field Name	Unit	Domain name	Description
Metadata ID			Automatically numbered field; does not require input
Pipeline operator ID			Automatically numbered field; does not require input
Pipeline ID			Automatically numbered field; does not require input
Submit date			
List provinces			List of the provinces that are covered by the submitted data.
Datum		Datum type	
Measure unit		Measure unit	
Projection		Projection type	
Remarks			

NOTE Domain name should be chosen from the following list;

a) Product type:

1) crude oil;

2) product oil;

3) natural gas.

b) Operation status:
   1) in service;
   2) idle;
   3) repairing;
   4) constructing;
   5) abandoned.
c) Data quality type:
   1) excellent;
   2) very good;
   3) good;
   4) poor;
   5) unknown.
d) Update description:
   1) addition pipeline;
   2) spatial modification of the existing pipeline;
   3) attribute modification of the existing pipeline;
   4) both a spatial and attribute modification of the existing pipeline;
   5) deletion of the existing pipeline;
   6) no change to the existing pipeline.
e) Projection type:
   1) Albers Equal-Area (Conterminous US);
   2) Albers Equal-Area (Hawaii);
   3) Albers Equal-Area (Alaska);
   4) Beijing 54 Coordinate System 6 degree zone;
   5) Beijing 54 Coordinate System 3 degree zone;
   6) Equidistant Conic (North America);
   7) Equidistant Conic (Conterminous US);
   8) Geographic (Lat/Long);
   9) Lambert Conformal (North America);
   10) Lambert Conformal (Conterminous US);
   11) State Plane Coordinate System (SPCS);
   12) Universal Transverse Mercator (UTM);
   13) unknown;
   14) Xi'an 70 coordinate system 6 degree zone;
   15) Xi'an 70 coordinate system 3 degree zone;
   16) others.
f) Datum type:
   1) CGCS2000;
   2) WGS74;
   3) NAD73;
   4) NAD27;
   5) GRS70;

6) others;

7) unknown.

g) Measure unit:

1) decimal degrees;

2) meters;

3) kilometres.

h) CCA type:

1) unknown;

2) high population area;

3) other populated area;

4) rivers;

5) traffic facilities;

6) environmental sensitive area;

7) others.

i) Class area:

1) unknown;

2) class 1;

3) class 2;

4) class 3;

5) class 4;

6) class 5;

7) others.

j) Threaten factor type:

1) unknown;

2) corrosion;

3) error operation;

4) manufacturing and construction defects;

5) geological hazards;

6) third damage.

ρAnnex H
(informative)
Statistics of pipeline failure information

Samples of statistics forms of pipeline failure information are given from Tables H.1 to H.5.

Table H.1 — Sample table of basic information of incidents

Basic information of incidents	
Pipe name	
Date of pipe failure	
Reference name of site of failure	
Milepost/ stationing number	
Offset/m	
Primary pipeline element of failure	
Pipe diameter of failure position /mm	
Wall thickness of failure position/mm	
Buried depth of pipe at failure position/m	
Pressure at the time of failure/MPa	
Local environment at the failure position	
Failure location class (1-5)	
Identified CCA (Y/N)	

Table H.2 — Sample table of failure mode and cause

Failure mode and cause	
Direct attributed cause of failure	
Root cause of failure	
Class of failure incidents	
Failure mode	
Approach of failure discovery	
Investigator information	
Type of damage	
Size of damage	

Table H.3 — Sample table of incident loss

Incident loss

Was there an explosion?	
Was there product ignition?	
Leakage	
Leakage unit	
Death toll	
Number of seriously-injured persons	
Number of persons with minor injury	
Duration of shutdown/h	
Loss of shutdown	
Budgetary fund of emergency response	
Loss of production damage	
Loss of environmental damage	
Loss of other damages	
Total loss	

Table H.4 — Sample table of information about maintenance

Information about maintenance	
Pressure test needed	
Date of pressure test	
Medium of pressure test	
Time of pressure maintaining/h	
Anomalies founded in pressure test	
Description of anomalies found during pressure test	
Was ILI is conducted before the incident?	
Date of ILI	
Type of ILI	
Was there any correlating anomaly is found in ILI data?	
Anomalies founded in ILI	
Description of other inspection	

Table H.5 — Sample table of information about emergency response

Information about emergency response	
Name of maintenance and emergency repair team	
Time on road/h	
Repair time/h	
Length of replaced pipe/m	

σArea of replaced coating/m2	
Length of re-welding/m	
Number of replaced valves/p.c.	
Others (written description)	
Remarks	

Annex I
(informative)
Outline requirements for pipeline management qualification training and accreditation at each level

I.1 Training objectives of Level 1 management qualification

The objectives of Level 1 pipeline integrity management training programs include:

a) Fundamental concepts and knowledge of pipeline integrity management and capable of implementing requirements of integrity in line with standards or system-related documents.

b) Awareness of data acquisition and identification of routine maintenance data and other related methods; including:

 1) able to conduct or assist in data collection project; and

 2) able to correctly use specifications relating to critical consequence area identification.

c) Identify and acquire data types related to potential risks; including:

 1) identify significant near misses;

 2) risk and control measures relating to pipeline inspection;

 3) assist in pipeline inspection;

 4) awareness of detailed procedures and requirements for common repair methods of pipeline defects;

 5) monitor and assist in repair works of pipeline defects;

 6) conduct tests on pipeline patrol and cathodic protection system as per standard or system, including repair oversight according to established company procedure.

I.2 Training objectives of Level 2 management qualification

The objectives of Level 2 pipeline integrity management training programs include:

a) Master processes and stipulated requirements for integrity management and capable of competent recommendations to integrity management decision-making processes resulting from assessment results and independently prepare an IMP.

b) Awareness of broader implementation of pipeline integrity within a pipeline operating company; including:

 1) present specific requirements for data collection projects, such as for requirements of integrity management;

 2) independently prepare and review data collection plans;

 3) correctly apply relevant specifications for critical consequence area identification;

4) understand advantages and weaknesses of a number of risk assessment methods and correctly interpret assessment results;

5) understand work flows, risks and control measures of in-line inspection and above ground inspection survey operations and assist in the implementation of inspection operations;

6) master application of inspection reports and specific procedures and requirements for common repair methods for pipeline defects;

7) monitor and supervise works of pipeline defect repairs;

8) conduct tests on pipeline patrols and cathodic protection systems as per standards or system procedures;

9) independently handle substandard systems as found in pipeline patrols or testing according to established procedures;

10) independently perform root cause analyses for integrity problems including identification of intrinsic problems of other pipelines by cross- comparison.

I.3 Training course outline for Level 3 management qualification

I.3.1 General

Level 3 training should be conducted for senior personnel and managers who get the certification of Level 2 and should be trained according to specifics majors.

I.3.2 Comprehensive integrity management and system management

Training objectives include:

a) capability and competence to research and develop system and methods of integrity management;

b) produce and establish reasonable integrity management decisions according to assessment results, available procedures, standards and prepare IMPs;

c) capable of independently conducting pipeline integrity management work or manage teams doing such works;

d) prepare or revise documentation of integrity management systems in line with results of integrity management.

I.3.3 Data management

Training objectives include:

a) competent understanding of pipeline data models, data dictionaries and GIS technologies;

b) gathering, integration and management of pipeline data and other related technologies and data sources;

c) correctly analyse and interpret data;

d) aware of types of pipeline data including ability to independently specified requirements for data collection projects according to integrity management requirements, prepare and review data collection plans;

f) independently prepare and organize data collection and analysis and other related works.

I.3.4 Risk assessment and CCAs identification management

Training objectives include:

a) competent understanding to identify and determine CCAs;

b) identification and computation of types of risks;

c) familiar with technical methods for assessing various risks and choose suitable assessment methods according to different pipeline characteristics;

d) independently organize and develop pipeline risk assessment and prepare risk assessment report.

I.3.5 Pipeline inspection and assessment management

Training objectives include:

a) competent understanding of basics of pipeline inspection technology and fitness for purpose assessments of defects;

b) competently identify risks and control measures for field inspection operations;

c) assist in implementations of inspection operations and be able to select in-line inspection technology that relates to risk and integrity assessments of pipelines;

d) selection of defect assessment methods and their application to results of inspection reports;

e) be familiar with universally-applied defect assessment methods;

f) be able to organize in-line and external inspection projects;

g) be able to organize and compile reports on pipeline integrity assessment.

I.3.6 Management of pipeline defect repair

Training objectives include:

a) competently understand principles and methods for pipeline defect repair;

b) causes for formulating specification of procedures and standards relating to pipeline defect repair;

c) provide recommendations regarding repair plan, including references to cases and experiences in pipeline defect repair construction management, such as knowledge about repair methods and technologies;

d) when practical conditions fail to meet stipulated requirements and need to adopt appropriate methods as from relevant standards, practices and procedures regarding pipeline repair, understanding repair techniques including regulations in locating and excavating pipeline defects;

e) generation of field excavation and repair reports.

I.3.7 Pipeline maintenance

Training objectives include:

a) competent understanding of pipeline corrosion and corrosion protection methods including relevant technical standards;

b) capable of conducting infield cathodic protection testing and adjustment; and pipeline patrol management;

c) understand characteristics of various pipeline coatings;

d) conduct root cause analyses on identified issues and identify underlying potential problems in other pipelines by comparison;

e) propose remedial measures for identified problems and recommend preventative measures to avoid potential future problems.

I.4. Qualification training and requirements for accreditation

Table I.1 gives the outline of training courses and requirements for accreditation at each level.

Table I.1 — Detailed requirements for pipeline management qualification training and accreditation at each level

Level	Requirements for accreditation qualifications	Competency	Outline of training courses	Requirements for accreditation
Level 1	Has one year or more pipeline integrity management or 2 years or more of relevant operations experience	Comprehensive integrity management	Basic knowledge for pipeline integrity management System management knowledge	Personnel with two years of related work experiences will be considered qualified Personnel that have less than two years of experience are required to take training and pass relevant examinations to achieve qualification
		Data management	Pipeline data collection method Application of pipeline integrity management system	Personnel with two years of related work experience will be considered qualified Personnel that have less than two years of experience are required to take training and pass relevant examinations to achieve qualifications
		Risk assessment and CCAs analysis management	Risk identification and assessment basis CCAs analysis technology Management introduction and investigation identification of geological disaster risks	Personnel with two years of related work experience will directly be accredited as qualified Personnel that have experiences of less than two years are required to take training and pass relevant examinations for qualification accreditation
		Pipeline inspection and assessment management	Basic knowledge of in-line inspection Basic knowledge of external inspection Basics of utility cleaning	Personnel with two years of related work experience will be considered qualified Personnel that have experience of less than two years are required to take

Level	Requirements for accreditation	Competency	Outline of training courses	Requirements for accreditation
			technology, specifically as needed prior to in-line-inspection	training and pass relevant examinations for qualification accreditation
		Repair management for pipe defects	Repair technology of pipe defects of liquid & gas steel pipelines	Personnel with two years related work experience will directly be accredited as qualified Personnel that have experience of less than two years are required to take training and pass relevant examinations for qualification accreditation
		Pipeline maintenance	Pipeline safety protection law Pipeline ground identification management Third-party construction supervision and management	Personnel with over two years work experience relating to integrity management will directly be accredited as qualified Personnel that have experience of less than two years are required to take training and pass relevant examinations for qualification accreditation
Level 2	Have related knowledge and background and engage in integrity management for over two years or engage in pipeline management for over five years	Pipeline maintenance	Line construction operation management Construction technology of hydraulic protection project Management of construction operations on pipeline crossing(crossing of water, highway and railway, etc.) and other special places Management of line construction safety	Qualifications of personnel will be accredited by interview after taking relevant training, qualification, accreditation
		Data management	Application of pipeline integrity management system Performance management Failure library management GIS and pipeline data model	Qualifications of personnel will be accredited by interview after taking relevant training
		Risk assessment and CCAs analysis management	Pipeline risk assessment technology Regulations and normative specifications relevant to pipeline risk assessment Risk assessment method application Geological disaster investigation and identification	Qualifications of personnel will be accredited by interview after taking relevant training
		Pipeline inspection and assessment management	Basic principles and application for pipeline in-line inspection Technical basis for defect assessment	Qualifications of personnel will be accredited by interview after taking relevant training

Level	Requirements for accreditation	Competency	Outline of training courses	Requirements for accreditation
		Repair management for pipe defects	Basic principles and methods for excavation validation of defect points	Qualifications of personnel will be accredited by interview after taking relevant training
Level 3	Senior managers with related technical background Engage in pipeline integrity management for at least three years	Integrity system management	Integrity plan design and examination Best events for pipeline integrity management	Qualifications of personnel will be accredited by interview after taking relevant training
		Data management	Review of pipeline integrity data Data analysis	Qualifications of personnel will be accredited by interview after taking relevant training
		Risk assessment and CCAs analysis management	Pipeline risk assessment Geological disaster investigation and identification Risk identification and assessment Critical consequence area identification standard	Qualifications of personnel will be accredited by interview after taking relevant training
		Pipeline inspection and assessment management	Pipeline in-line inspection management Technology of applicability evaluation for pipeline engineering Pipeline external inspection management	Qualifications of personnel will be accredited by interview after taking relevant training
		Repair management of pipe defects	Technology of pipe defect repair for liquid and gas steel pipelines Basis and methods for excavation validation of defect points	Qualifications of personnel will be accredited by interview after taking relevant training
		Pipeline maintenance	Legal applicability of pipeline safety protection Third-party construction supervision and management Pipeline ground identification management Selection and inspection of pipeline coating Repair technology of coating Anticorrosion principles and mechanism Stray current determination and analysis Risks of cathodic protection system Risks of coating system	Qualifications of personnel will be accredited by interview after taking relevant training

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