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Petroleum and natural gas industries — Well integrity —

Part 1: Life cycle governance

Pétrole et industries du gaz naturel — Intégrité du puits —

Partie 1: Gouvernance du cycle de vie

Reference number
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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 voluntary nature of standards, 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 petroleum, petrochemical and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

A list of all parts in the ISO 16530 series can be found on the ISO website.

Introduction

This document has been developed by oil and gas producing operating companies and is intended for use in the petroleum and natural gas industries worldwide. This document is intended to provide guidance to the well operator on managing well integrity throughout the well life cycle. Furthermore, this document addresses the minimum compliance requirements for the well operator in order to claim conformity with this document.

It is necessary that users of this document are aware that requirements over and above those outlined herein may be needed for individual applications.

This document addresses the process of managing well integrity during each of the well life cycle phases, namely: basis of design; design; construction; operation; intervention (including work-over) and abandonment.

The following terminology, in line with ISO/IEC Directives, is used in this document:

a) The term “shall” denotes a minimum requirement in order to conform to this document.

b) The term “should” denotes a recommendation or that which is advised but not required in order to conform to this document.

c) The term “may” is used to indicate a course of action permissible within the limits of this document.

d) The term “can” is used to express possibility or capability.

In addition, the term “consider” is used to indicate a suggestion or to advise.

The phases of a well life cycle have separate and distinct requirements for achieving well integrity management objectives, but all phases have common elements and techniques. Clause 5 discusses these common elements and techniques. Clauses 6 to 11 discuss each individual phase and its requirements. Additionally, each clause highlights the aspects to be considered within the common elements and techniques as applicable to that phase.

Figure 1 summarizes the elements which are common among phases, and the relation between the phases.

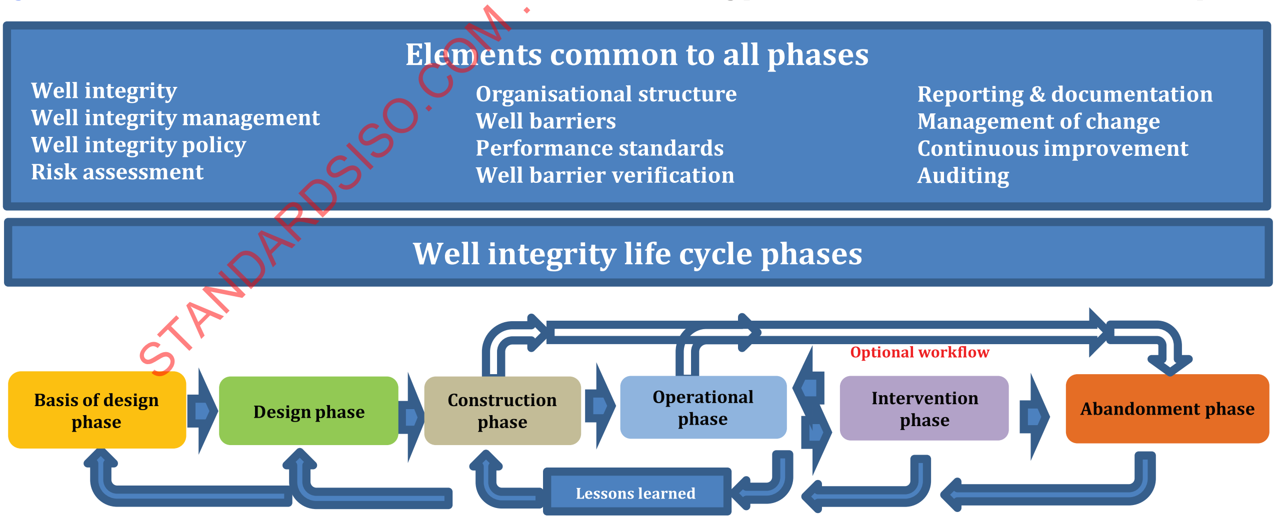


Figure 1 — Elements common to the phases of well integrity management

Petroleum and natural gas industries — Well integrity —

Part 1: Life cycle governance

1 Scope

This document is applicable to all wells that are operated by the petroleum and natural gas industry. This document is applicable to any well, or group of wells, regardless of their age, location (including onshore, subsea and offshore wells) or type (e.g. naturally flowing, artificial lift, injection wells).

This document is intended to assist the petroleum and natural gas industry to effectively manage well integrity during the well life cycle by providing:

— minimum requirements to ensure management of well integrity; and

— recommendations and techniques that well operators can apply in a scalable manner based on a well's specific risk characteristics.

Assuring well integrity comprises two main building blocks: the first is to ensure well integrity during well design and construction, and the second is to manage well integrity throughout the remaining well life thereafter.

This document addresses each stage of the well life cycle, as defined by the six phases in a) to f), and describes the deliverables between each phase within a Well Integrity Management system.

a) The "**Basis of Design Phase**" identifies the probable safety and environmental exposure to surface and subsurface hazards and risks that can be encountered during the well life cycle. Once identified, these hazards and risks are assessed such that control methods of design and operation can be developed in subsequent phases of the well life cycle.

b) The "**Design Phase**" identifies the controls that are to be incorporated into the well design, such that appropriate barriers can be established to manage the identified safety and environmental hazards. The design addresses the expected, or forecasted, changes during the well life cycle and ensures that the required barriers in the well's design are based on risk exposure to people and the environment.

c) The "**Construction Phase**" defines the required or recommended elements to be constructed (including rework/repair) and verification tasks to be performed in order to achieve the intended design. It addresses any variations from the design which require a revalidation against the identified hazards and risks.

d) The "**Operational Phase**" defines the requirements or recommendations and methods for managing well integrity during operation.

e) The "**Intervention Phase**" (including work-over) defines the minimum requirements or recommendations for assessing well barriers prior to, and after, any well intervention that involves breaking the established well barrier containment system.

f) The "**Abandonment Phase**" defines the requirements or recommendations for permanently abandoning a well.

The six phases of the well life cycle, as defined in this Scope, and their interrelationships, are illustrated in Figure 1 in the Introduction.

This document is not applicable to well control. Well control refers to activities implemented to prevent or mitigate unintentional release of formation fluids from the well to its surroundings during drilling, completion, intervention and well abandonment operations, and involves dynamic elements, i.e. BOPs, mud pumps, mud systems, etc.

This document is not applicable to wellbore integrity, sometimes referred to as "borehole stability". Wellbore integrity is the capacity of the drilled open hole to maintain its shape and remain intact after having been drilled.

2 Normative references

There are no normative references in this document.

3 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:

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

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

3.1
A-annulus
designation of the annulus between production tubing and production casing

[SOURCE: API RP 90, modified]

3.2
acceptance criteria
specified limits of acceptability applied to process, service, or product characteristics

3.3
as low as reasonably practicable
ALARP
implementation of risk-reducing measures until the cost (including time, capital costs or other resources/assets) of further risk reduction is disproportional to the potential risk reducing effect achieved by implementing any additional measure

Note 1 to entry: See UK HSE.[27]

3.4
ambient pressure
pressure external to the wellhead

Note 1 to entry: In the case of a surface wellhead, the pressure is 0 kPa (0 psig). In the case of a subsea wellhead, it is equal to the hydrostatic pressure of seawater at the depth of the subsea wellhead.

[SOURCE: API RP 90, modified]

3.5
anomaly
condition that differs from what is expected or typical, or which differs from that predicted by a theoretical model

3.6
availability
extent to which the system/structure/equipment is capable of retaining its functional integrity

3.7
B-annulus
designation of an annulus between the production casing and the next outer casing

Note 1 to entry: The letter designation continues in sequence for each outer annulus space encountered between casing strings, up to and including the surface casing and conductor casing strings.

[SOURCE: API RP 90, modified]

3.8
breaking of containment
controlled entry into the containment system of integrity or barrier

3.9
casing liner
casing string with its uppermost point inside a previous casing string and not in the wellhead

3.10
competence
ability of an individual to perform a job properly through a combination of training, demonstrated skills, accumulated experience and personal attributes

3.11
component
mechanical part, including cement, used in the construction of a well

3.12
conductor casing
component that provides structural support for the well, wellhead and completion equipment, and often used for hole stability for initial drilling operations

Note 1 to entry: This casing string is not designed for pressure containment, but upon completion of the well it might have a casing head; therefore, it can be capable of containing low annulus pressures. For subsea and hybrid wells, the low-pressure subsea wellhead is normally installed on this casing string.

[SOURCE: API RP 90, modified]

3.13
consequence
expected effect of an event that occurs

3.14
containment
preventing release of fluid

3.15
deep-set
close to, or at, the cap rock of a reservoir or a depth where it is possible to achieve an overbalance pressure with an hydrostatic column to counter act the maximum anticipated pressure from below

3.16
deviation
departure from a standard

3.17
dispensation
approval to operate with a deviation from a requirement

3.18
extended leak off test
XLOT
application of pressure by superimposing a surface pressure on a fluid column in order to determine the pressure at which a fracture propagates into the exposed formation and also establishes the fracture closure pressure

3.19
failure
loss of ability to perform as required

3.20
failure mode
effect by which a failure is observed on the failed item

3.21
failure modes and effects analysis
FMEA
technique which identifies failure modes and mechanisms, and their effects

3.22
failure mode, effects, and criticality analysis
FMECA
analysis usually performed after an *FMEA* (3.21) which can be based on the probability that the failure mode will result in system failure, or the level of risk associated with the failure mode, or a risk's priority

3.23
fault
abnormal, undesirable state of a system element induced by the presence of an improper command or absence of a proper one, or by a failure

Note 1 to entry: All failures cause faults; not all faults are caused by failure.

Note 2 to entry: System elements can include, for example, an entire subsystem, an assembly, or a component.

3.24
flow-wetted
<surface> coming into direct contact with the dynamic movement of well fluids in the flow stream

[SOURCE: API Spec 11D1]

3.25
fluid
substance that has no fixed shape and yields easily to external pressure

Note 1 to entry: A fluid can be either a gas or a liquid.

3.26
formation integrity test
FIT
application of pressure by superimposing a surface pressure on a fluid column in order to determine ability of a subsurface zone to withstand a certain pressure

3.27
formation strength
pressure that the formation can withstand

3.28
functionality
operational requirements of the system/structure/equipment in order to establish and maintain integrity

3.29
hazard
source of potential harm or a situation with a potential to cause loss (any negative consequence)

3.30
hybrid well
well drilled with a subsea wellhead and completed with a surface casing head, a surface tubing head, a surface tubing hanger and a surface tree

Note 1 to entry: A hybrid well can have either one (single-bore production riser) casing string or two (dual-bore production riser) casing strings brought up from the subsea wellhead and tied back to the surface equipment. These wells are typically located on floating production platforms, e.g. tension-leg platforms (TLPs).

[SOURCE: API RP 90, modified]

3.31
impairment
state of diminished ability to perform a function, without having yet failed

3.32
imposed annulus pressure
annulus pressure that is imposed for purposes such as gas lift, water injection, thermal insulation, etc.

[SOURCE: API RP 90, modified]

3.33
inflow testing
leak test of well barrier element by creating a differential pressure and observing for pressure change on the low pressure side

Note 1 to entry: See also 5.9.3.3.

3.34
intervention
operation to enter the well which requires breaking containment of an existing well barrier

3.35
leak
unintended and undesired movement of fluids

3.36
leak off test
LOT
application of pressure by superimposing a surface pressure on a fluid column in order to determine the pressure at which the exposed formation accepts whole fluid

[SOURCE: API RP 59, modified]

3.37
major accident
incident such as an explosion, fire, loss of well control, release of oil, gas or dangerous substances causing, or with significant potential to cause, damage to facilities, serious personal injury or widespread persistent degradation of the environment

3.38
major accident hazard
MAH
hazard with a potential for causing a *major accident* (3.37)

3.39
maximum allowable annulus surface pressure
MAASP
p_{MAASP}
greatest pressure that an annulus can contain, as measured at the wellhead, without compromising the integrity of any element of that annulus, including any exposed open-hole formations

3.40
monitoring
observation of the operating parameters of a well, via instrumentation, on a predefined frequency to ensure that they remain within their operating limits

Note 1 to entry: Examples of well operating parameters include pressures, temperatures, flow rates.

3.41
operated well
well for which the well operator has control and management of operations

3.42
operating limits
set of established criteria, or limits, beyond which a device or process should not be operated

3.43
outflow
fluids that flow out of one place to another, typically out of a well

3.44
performance standard
statement, which can be expressed in qualitative or quantitative terms, of the performance required of a system or item of equipment in order for it to satisfactorily fulfil its purpose

3.45
pressure test
application of pressure to a piece of equipment or a system to verify the pressure containment capability for the equipment or system

3.46
primary well barrier
first set of well barrier elements that prevent flow from a source of inflow

3.47
production casing
innermost string of casing in the well

[SOURCE: API RP 90, modified]

3.48
production riser
casing strings rising from the seafloor to the wellhead (fixed platforms) or casing strings attached to the subsea wellhead rising from seafloor to a surface wellhead (hybrid wells)

3.49
production string
completion string
string consisting primarily of production tubing, but also including additional components such as the surface-controlled subsurface safety valve (SCSSV), gas-lift mandrels, chemical injection and instrument ports, landing nipples, and packer or packer seal assemblies

Note 1 to entry: The production string is run inside the production casing and is used to conduct production fluids to the surface.

[SOURCE: API RP 90, modified]

3.50
production tubing
tubing that is run inside the production casing and used to convey produced fluids from the hydrocarbon-bearing formation to the surface

Note 1 to entry: Tubing can also be used for injection. In some hybrid wells, for example, tubing is used as a conduit for gas for artificial lift below a mudline pack-off tubing hanger to isolate the gas-lift pressure from the production riser.

[SOURCE: API RP 90, modified]

3.51
reliability
ability of an item to perform a required function under given conditions for a given time interval

3.52
residual risk
risk that remains after controls have been implemented

3.53
risk
combination of the consequences of an event and the associated likelihood of its occurrence

3.54
risk assessment
overall process of risk identification, risk analysis and risk evaluation

[SOURCE: ISO Guide 73:2009, 3.4.1]

3.55
risk register
tool to record, follow up and close out actions related to relevant assessed risks

Note 1 to entry: Each entry in the risk register typically includes a description of the risk, a description of the action(s), the responsible party, the due date, and status of the action.

3.56
safety-critical element
SCE
part of a facility, including computer programs, whose purpose is to prevent or limit the consequences of a major accident, or whose failure could cause or contribute substantially to a major accident

Note 1 to entry: Safety critical elements include measures for prevention, detection, control and mitigation (including personnel protection) of hazards.

[SOURCE: EU Directive 2013/30/EU, modified]

3.57
secondary well barrier
second set of well barrier elements that prevent flow from a source of inflow

[SOURCE: API RP 90, modified]

3.58
shut-in well
well with one or more valve(s) closed on the flow path

3.59
subsea well
well completed with a subsea wellhead and a subsea tree

[SOURCE: API RP 90, modified]

3.60
subsea wellhead
wellhead that is installed at or near the seabed

3.61
surface casing
casing that is run inside the conductor casing to protect shallow water zones and weaker formations

Note 1 to entry: Surface casing can be cemented within the conductor casing and is often cemented back to the mud-line or surface.

Note 2 to entry: The surface wellhead is normally installed on this casing for surface wells.

[SOURCE: API RP 90, modified]

3.62
surveillance
continual, checking, supervising, critically observing or determining the status in order to identify change from the performance level required or expected

Note 1 to entry: Examples of well physical characteristics include tubing wall thickness measurements, visual inspections, sampling.

3.63
suspended well
well that has been temporarily isolated from the producing reservoir

Note 1 to entry: Components above the isolation device are no longer considered flow-wetted.

3.64
sustained casing pressure
SCP
pressure in an annulus that

a) rebuilds after having been bled down;

b) is not caused solely by temperature fluctuations; and

c) is not a pressure that has been imposed by the well operator

Note 1 to entry: Sustained casing pressure can be present on wells without annular access.

[SOURCE: API RP 90, modified]

3.65
thermally induced annulus pressure
pressure in an annulus generated by thermal expansion or contraction of trapped fluids

Note 1 to entry: On wells where there is no annulus access, sustained casing pressure can be present.

[SOURCE: API RP 90, modified]

3.66
type testing
testing of a representative specimen (or prototype) of a product which qualifies the design and, therefore, validates the integrity of other products of the same design, materials and manufacture

3.67
verification
examination, testing, audit or review to confirm that an activity, product or service is in accordance with specified requirements

3.68
well abandonment
permanent subsurface isolation to prevent any undesired communication between any distinct zones and fluid movement out of a well using validated well barriers

3.69
well barrier
system of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well

3.70
well barrier element
WBE
one of several dependent components that are combined to form a well barrier

3.71
well barrier plan
well operator's specific programme for barrier placement and verification in a well to prevent unplanned flow during each stage of well construction, operation, abandonment or decommissioning

3.72
well handover
act or process that formalises the transfer of a well, and operating responsibility, from one competent party to another, including the requisite data and documents

3.73
well integrity
containment and prevention of the escape of fluids to subterranean formations or surface

3.74
well integrity management
application of technical, operational and organizational methods to prevent the uncontrolled flow of fluids at the surface or across subsurface formations throughout the life cycle of the well

3.75
well operator
company that has responsibility for the well

3.76
well operating limits
combination of parameters established by the well operator within which the well should be operated to ensure that all component specifications, including their applicable design or safety factors and performance standards, are not violated throughout the well life cycle

3.77
well status
well's current operational function

Note 1 to entry: Functions include undergoing construction, in operation (i.e. producing, injecting, shut-in), undergoing intervention, suspended, or abandoned.

3.78
well stock
portfolio of wells for which the well operator has operating or well integrity assurance responsibility

4 Abbreviated terms

ALARP	as low as reasonably practicable
API	American Petroleum Institute
ASV	annulus safety valve
BOP	blow-out preventer
BS&W	base sediment and water
ECD	equivalent circulating density
ESD	emergency shutdown
FIT	formation integrity test
FMEA	failure modes and effects analysis
FMECA	failure mode and effects and criticality analysis
FS	formation strength
HPHT	high pressure and high temperature
ID	internal diameter
KPI	key performance indicator
LOT	leak-off test
MAASP	maximum allowable annulus surface pressure
MAH	major accident hazard
MFL	magnetic flux leakage
MOC	management of change
NORM	naturally occurring radioactive material
NORSOK	Norsk Sokkels Konkurranseposisjon
OD	outer diameter
OEM	original equipment manufacturer
QA	quality assurance
QC	quality control

QRA	quantitative risk assessment
RACI	responsible, accountable, consulted, informed
ROV	remotely operated vehicle
SCE	safety-critical element
SCP	sustained casing pressure
SCSSV	surface controlled subsurface safety valve
SPM	side pocket mandrel
SIMOPS	simultaneous operations
SSCSV	subsurface controlled subsurface safety valve
SSSV	subsurface safety valve
SSV	surface safety valve
TOC	top of cement
TVD	true vertical depth
WBE	well barrier element
WIMS	well integrity management system
XLOT	extended leak-off test

5 Common elements of the well integrity life cycle

5.1 General

The phases of the life cycle of a well have common elements, methods and processes, which are integral to the management of well integrity. This clause identifies and discusses these elements, which are outlined in Figure 1 in the Introduction.

Major accident hazards (MAH) and the risks they present to people, the environment and facilities in the oil and gas industry require stringent management. While this document describes requirements and recommendations for managing well integrity, it should be realized that well integrity is an integral part of asset integrity (see Reference [22]) and process safety (see Reference [23]).

This document covers the full well life cycle, including design. Another International Standard closely linked with design is ISO 17776, which establishes the requirements for the effective planning and execution of risk reduction through design hazard management of MAHs, and focuses on the process of conducting hazard management rather than providing detailed requirements as to how each individual activity should be conducted.

Safety-critical elements (SCEs) are the equipment and systems, which provide the basis to manage the risks associated with MAHs. The proper and reliable functioning of SCEs is hence critical to managing MAHs. The well operator should define SCEs in their well designs, taking into consideration applicable regulatory statutes.

5.2 Well integrity

Well integrity refers to maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between formations with different pressure regimes or loss of containment to the environment.

5.3 Well integrity policy

The well operator shall have a policy that defines their commitments and obligations to safeguard health, safety, environment, asset and reputation with respect to well integrity. This policy will detail how well integrity is established and preserved through a documented management system that is applied to all wells under the well operator's responsibility.

5.4 Well integrity management system

The well operator should have a well integrity management system (WIMS) to ensure that well integrity is maintained throughout the well life cycle by the application of a combination of technical, operational and organizational processes.

The WIMS should address the following elements for the well operator's well stock:

— risk assessment;

— organizational structure (roles, responsibilities, accountabilities and competencies);

— well barriers;

— performance standards;

— well barrier verification;

— reporting and documentation;

— management of change process;

— continuous improvement process;

— auditing.

5.5 Risk assessment

5.5.1 General

The well operator shall identify the well integrity hazards over the life cycle of the well and identify the risk associated with these hazards. Risk is defined by the likelihood of event occurrence and the consequences should the event occur. The well operator should determine acceptance levels for likelihood and consequence.

Techniques that can be applied for risk assessment are listed in Annex A. The assessment of a well integrity-related event can be depicted on a risk assessment matrix such that risk can be categorised or ranked based on the combined effects of consequence and likelihood of event occurrence. An example of a '5 × 5' risk assessment matrix is given in Figure 2.

For risks exceeding the well operator's acceptance levels, control measures and mitigations should be put in place to reduce the risk to the well operator's defined risk tolerance level. ALARP principles can be used to determine whether additional controls or mitigations are required to further reduce the level of risk.

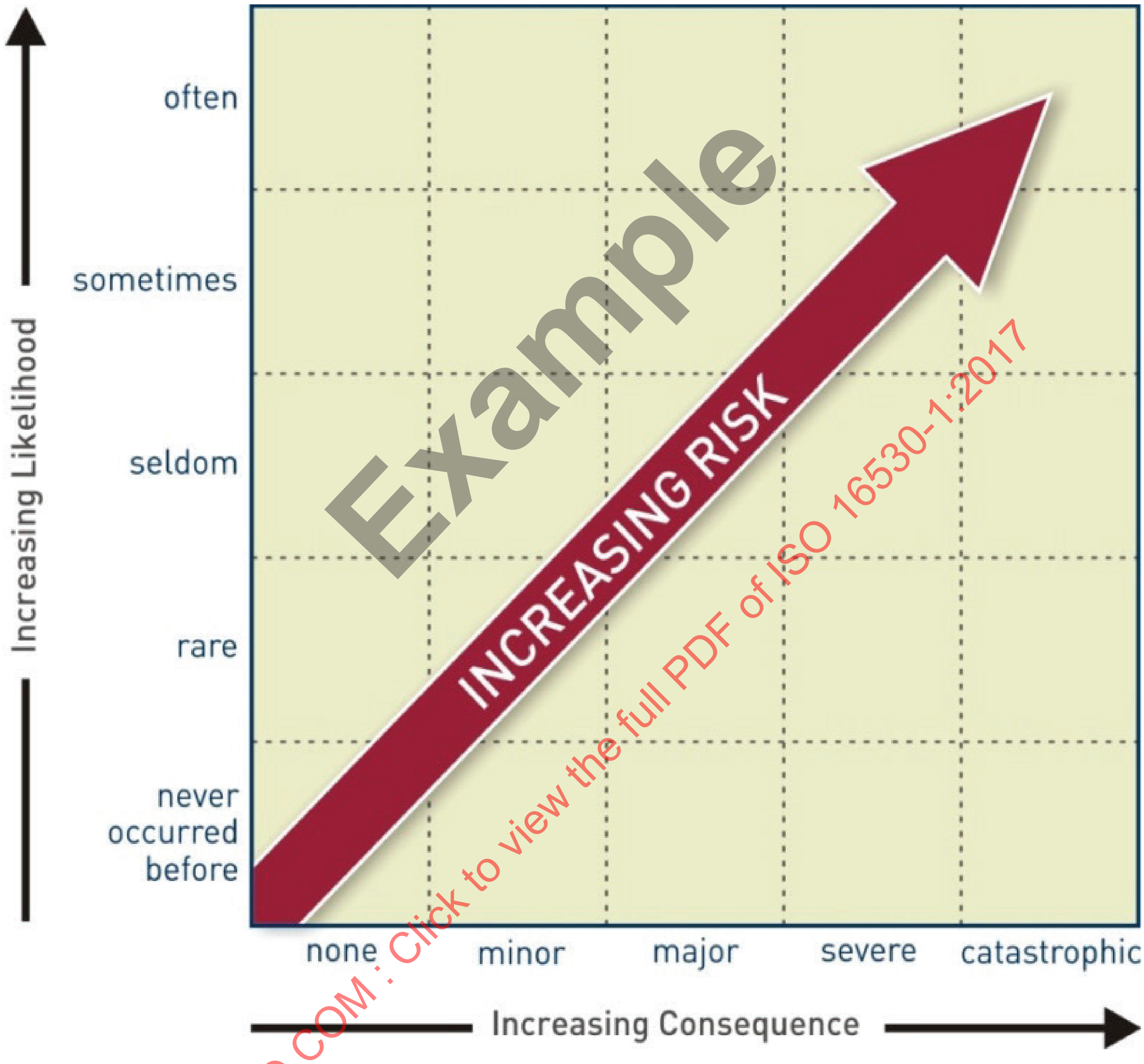


Figure 2 — Example of a risk assessment matrix

5.5.2 Risk register

The well operator should establish a risk register for all the identified hazards and risks, which is to be maintained and communicated to all relevant personnel throughout the well life cycle.

The risk register should contain, but is not limited to, the following:

— identified hazards;

— existing safeguards, mitigations and control measures;

— initial risk description(likelihood and consequences);

— plan for implementation of control measures;

— description of risk after control measures.

An example of a risk register can be found in Annex B.

5.5.3 Well type risk profile

The risks defined in the risk register of the well(s) determine the elements of the well type risk profile for that given asset.

The well operator may have several different types of wells that are covered by their WIMS; well types can include e.g. water injectors, gas producers, disposal wells and oil producers. In such circumstances, especially when developing a field, it can be expedient to develop risk profiles for each well type. The use of such a risk profile allows consistent management of well barriers.

5.6 Organizational structure and tasks

The well operator should ensure that resources in its organization are available to manage well integrity throughout the entire life cycle of the well.

The well operator should define the roles and responsibilities for all professional, supervisory, operational and maintenance personnel required for well integrity management. Roles and responsibilities should be documented, for example in a RACI matrix (see Annex C).

Personnel competence requirements are analogous to performance standards for well barrier elements (WBEs). Different competencies are required for the various phases of the well life cycle. The well operator should ensure that personnel (employees and contractors) involved in WIMS activities are competent to perform the tasks assigned to them and that competencies are appropriate for each phase of the well life cycle. An example of a competence matrix is given in Annex D. This matrix does not reflect the full range of competences required, but should be used by the well operator as a basis for developing a more rigorous and comprehensive matrix that represents the range of wells, their geographical locations, the operating regimes and the various skills required for all personnel working on well integrity related activities.

The well operator should define well integrity personnel competence requirements and the relevant training to ensure that tasks are carried out in a manner which is safe with regard to the protection of health, environment and assets. A competence performance record should be maintained that demonstrates conformance with the competency requirements.

NOTE 1 Competence can be gained through a combination of education, training programmes, mentoring, self-study and on-the-job training (transfer of experience/expertise).

NOTE 2 See ISO/TS 17969, which details the requirements of a competence management system and application to well operations personnel. The document includes example competence profiles which include competencies directly relevant to well integrity.

5.7 Barriers

5.7.1 General

Barriers are defined as a combination of components or practices that contribute to the well system reliability to prevent or stop uncontrolled fluid flow.

Barriers may be:

— hardware barriers (equipment which is designed, installed and verified);

— operational barriers (monitoring equipment, practices and procedures);

— human barriers (competencies, training);

— administrative controls (assignment of roles, resource provision, auditing, reviews).

For the purpose of this document, hardware barriers are addressed as well barriers; other barriers are addressed in the respective clauses of this document.

Assurance that barriers are in place and maintained throughout the well life cycle is the basis for managing well integrity.

5.7.2 Barrier philosophy

The well operator shall define and document a barrier philosophy that specifies the principles to maintain control of the well fluids. The philosophy should describe the barriers (well, operational and human) and administrative controls that will be employed.

A system of multiple barriers and redundancy in well barrier elements is used to achieve a high level of reliability. Well reliability is achieved through the combination of individual barriers as a system and is not the result of the infallibility of a single component.

5.7.3 Well barriers

5.7.3.1 General

A well barrier is a combination of one or several well barrier elements (WBEs) that contain fluids within a well to prevent uncontrolled flow of fluids within, or out of, a well.

The verification, maintenance, inspection and testing of well barriers are key aspects of the management of well integrity throughout the entire well life cycle.

The well operator should track the status of each well barrier and maintain all well barrier(s) according to the specified well operating limits.

5.7.3.2 Well barrier objectives

The objectives of a well barrier are to:

— withstand the maximum anticipated combined loads to which it can be subjected;

— function as intended in the environments (pressures, temperature, fluids, mechanical stresses) that can be encountered throughout its entire life cycle;

— prevent uncontrolled flow of wellbore liquids or gases to the external environment or within the wellbore;

— successfully undergo scheduled verification tests (may not apply to abandoned wells).

Examples of typical well barrier elements, their functions and failure characteristics are given in Annex E.

5.7.3.3 Number of well barriers

At least two independently verified well barriers against uncontrolled outflow, along any potential flow or leak path, should be utilized where practicable.

Where it is not practicable to establish two independently verified barriers, a risk assessment should be performed to confirm that one well barrier provides an acceptable level of risk to maintain containment, including consideration of subsurface flow and the well's capability of flowing to surface.

The primary well barrier is typically the first set of well barrier elements exposed to the pressure source. The secondary well barrier is typically not exposed to the produced fluid or pressure but provides redundancy in the case of primary barrier failure. Examples of barrier diagrams per phase of operation are presented in Annex F.

5.7.3.4 Primary well barrier

For a well, the primary well barrier is typically, but not exclusively, composed of one or more of the following WBEs subject to the applicable life cycle phase:

— cap rock;

— drilling fluids;

— casing cement;

— production casing;

— production packer;

— completion string;

— SSSV or tree master valve.

5.7.3.5 Secondary well barrier

The secondary well barrier is typically, but not exclusively, composed of one or more of the following WBEs subject to the applicable life cycle phase;

— impermeable formation;

— completion fluids;

— casing cement;

— blow-out preventers;

— casing with hanger and seal assembly;

— wellhead with valves;

— tubing hanger with seals;

— tree and tree connection;

— actuated tree wing valve or master valve.

5.7.3.6 Well barrier schematic

The well operator should document the well barriers employed using a well barrier schematic (WBS), which also identifies the WBEs of each well barrier and the verification tests performed during the construction phase. A WBS can be used for an individual well or a well type.

The WBS normally contains the following types of information:

a) a drawing illustrating the primary and secondary well barriers;

b) formation integrity, when the formation is part of a well barrier;

c) reservoirs/potential sources of inflow;

d) tabulated listing of WBEs with initial verification and monitoring requirements against performance standards;

e) dimensions and depth labelling (TVD and MD) for all tubular goods and cement (including TOC) defined as WBEs;

f) calculated MAASP value for each annulus;

g) maximum allowable tubing head pressure;

h) well information including field/installation, well name, well type, well status, well/section design pressure, revision number and date, “Prepared by”, “Verified/Approved by”;

i) clear labelling of actual well barrier status, planned or as-constructed;

j) common WBEs across barriers;

k) a note field for important well integrity information (anomalies, exemptions, etc.).

An example of a WBS is presented in Annex F.

5.7.4 Operational barriers

Operational barriers are designed to prevent deviations from safe working practices, and to place worksite controls into operation on equipment and work methods in order to avoid human-related errors causing accidents or contributing to a hazard.

Examples of operational barriers are:

— detection and monitoring equipment;

— processes and work instructions;

— safety isolations and interlocks;

— permit-to-work system.

5.7.5 Human barriers

Human barriers are the skills and knowledge given to individuals to recognize hazards or deviations, and to take appropriate mitigating actions (response).

Examples of human barriers are:

— training;

— recognition and response;

— skills and competencies for response to risk;

— experience;

— supervisory skills.

The design and layout of equipment and their interfaces with personnel should be considered, in order to limit human error.

5.7.6 Administrative controls

An organization provides the structure and culture in which well integrity and its management are performed. As a part of this structure, administrative controls provide information on, support of and control of activities which are directly or indirectly related to well integrity.

Examples of administrative controls are:

— design standards;

— materials handling standards;

— procedures and policy manuals;

— change processes/escalation of decisions;

— quality assurance programme.

5.7.7 Impact barriers

Impact barriers are usually employed to prevent damage to primary and secondary well barriers as a result of some external impact. Such barriers can typically be conductors, crash frames, trawl net deflectors, concrete barricades and fencing.

5.8 Performance standards for equipment

5.8.1 General

In well integrity management there are several kinds of performance standards. These performance standards typically specify requirements in the following areas:

— people: standards for competence assessment;

— equipment (WBE): equipment performance standards and specifications;

— management system: standards defining key performance indicators and audits.

This subclause focuses on the performance standards for equipment. Other standards and requirements are covered in other subclauses.

The well operator should define performance standards for WBEs for each well type. Performance standards, supported by the risk assessment, are the basis for their design and selection, as well as for the development of maintenance and monitoring requirements.

The criteria to be determined for an equipment performance standard are the following:

a) functionality — what the equipment is required to do in order to establish and maintain integrity;

b) availability — ability of an item to be in a state to perform a required function under given conditions at a given instant of time, or on average over a given time;

c) reliability — the probability that the equipment will operate on demand when required to maintain integrity;

d) survivability — the ability of a component, a piece of equipment or a system to remain functional for a specified period when under attack from identified external loading events associated with a major accident;

e) interactions and dependencies with other equipment that is critical for functionality.

Equipment performance standards should be developed over time, as the well-type definition evolves and as risk and hazard studies are conducted to demonstrate the level of performance necessary for each WBE to perform its role in controlling risk. The well barriers, WBEs and equipment performance standards should be fully established by the end of the well design stage. The performance standards should specify the periodic inspection, maintenance and testing requirements.

An example of a performance standard is given in Annex G.

5.8.2 Well operating limits

Well operating limits are a combination of the criteria established by the well operator to ensure that the well remains within its design limits and its performance standard in order to maintain well integrity throughout the well life cycle.

The well operator should establish well operating limits for each well type as a part of the WIMS. Any changes in well configuration, condition, life cycle phase or status require the well operating limits to be checked and potentially updated.

The well operator should clearly define the following:

— responsibilities for establishing, maintaining, reviewing and approving the well operating limits;

— how each of the well operating-limit parameters should be monitored and recorded during periods when the well is constructed, operational, shut-in or suspended;

— requirements for any threshold settings for the well operating limits;

— actions that should be taken in the event a well parameter is approaching its defined threshold;

— actions, notifications and investigations required if well operating limit thresholds are exceeded;

— safety systems that are necessary to protect against exceeding the well operating limits.

5.9 Well barrier verification

5.9.1 General

A verification test is a check whether or not a WBE meets its acceptance criteria. It includes (but is not limited to) function testing, leak testing, axial load testing (tension and/or compression) and well load case modelling verification.

5.9.2 Function testing

5.9.2.1 General

Function testing is a check as to whether or not a well barrier or system is operating as intended. It should be realistic, objective, and the results should be recorded.

In cases where it is neither practical nor possible to perform a leak test, function testing may be accepted on its own as verification testing.

5.9.2.2 Function testing of valves

On manual valves, the function test indicates that the valve cycles (opens and closes) correctly by counting the turns of the handle and verifying that the valves cycle smoothly. On actuated valves, the test measures the opening and closing times and also confirms that the stem travels the full distance. The function test does not provide information about possible leakage of the valve.

Function testing of ESD/SSV valves may be carried out as defined in API/Std 6AV2. This method may also be applied to onshore wellhead and tree ESDs.

For some valves, where it is not possible to observe movement of the valve's stem, it may be possible to verify its correct functioning by observing the hydraulic signature (the control line pressure data and hydraulic fluid actuation volumes). Examples of the hydraulic signature of a surface-controlled subsurface safety valve (SCSSV) and a valve of a subsea tree are shown in Annex H.

5.9.3 Barrier verification testing

5.9.3.1 General

Barrier verification testing is the application of a differential pressure to ascertain the integrity of the sealing system of the component that is part of a barrier system. Differential pressure can be obtained by either pressure testing or inflow testing. An example of leak rate determination is provided in Annex I.

The well operator should define the assessment methods of testing, for example:

a) observation of flow against defined acceptance criteria; or

b) monitoring of pressure changes against defined acceptance criteria.

5.9.3.2 Pressure testing

Pressure testing is the application of a pressure from a known source to ascertain the mechanical and sealing integrity of the component.

Fluids introduced into the well, annuli and voids during testing should be assessed to ensure they do not affect well integrity, for example the possible introduction of sulfate-reducing bacteria or the ability to freeze in low temperature environments.

This may involve:

— using treated water (e.g. with low chloride and sulfur contents);

— increasing the pH of the test media;

— adding a biocide and oxygen scavenger to the test media;

— using non-freezing fluids such as brines or hydrocarbons;

— considering the use of an inert gas, such as nitrogen.

5.9.3.3 Inflow testing

Inflow testing, or negative testing, utilises pressure from an existing source such as reservoir or formation pressure. A WBE that is normally open is tested in the closed position (elements such as cement, casing and seals are considered closed).

The pressure downstream (i.e. on the side of the WBE opposite to the remote pressure source) of the WBE is reduced to create a pressure differential across it, and the volume downstream is monitored for a pressure increase that indicates a leak.

In the case of a successful valve inflow test, it can be assumed that the actuation system to close that valve is functioning to the extent that the valve closes. However, it does not necessarily confirm that the actuation system itself is functioning in accordance with its operating parameters, such as time-to-function, sufficient accumulator capacity, operating pressure, etc.

Subsurface safety valves can be verified only by an inflow test after closing the valve in accordance with the manufacturer's procedures. Inflow testing of subsurface controlled subsurface safety valves often requires that the well be lined up to a low-pressure test separator or a flare to simulate uncontrolled flow-to-surface conditions. If unable to perform inflow testing, the well operator should maintain such valves by establishing a replacement frequency (guidance can be found in ISO 10417).

5.9.4 Direction of flow

A component should preferably be tested in the direction of flow. If this is impossible or impractical, a test of the component in the opposite flow direction should be performed. The test in the opposite flow direction can be of limited value in establishing the component's ability to seal in the direction of flow. Any component tested in the opposite direction of flow should have this documented.

5.9.5 Effects of temperature

The effects of temperature changes should be taken into account, especially in subsea or arctic situations, since the wellbore, flow lines, manifolds, risers, etc., cool down quickly when remotely actuated valves are closed.

Temperature effects can influence leak test results and mask actual barrier performance, causing inaccurate leak test interpretation. The duration of the test might have to be reviewed.

In these cases, establishing a leak test might not be possible and it may be necessary for valve testing to rely on indirect indications, such as the temperature itself or interpretation of control-line pressure response characteristics.

5.9.6 Modelling verification

Certain WBEs might have to be verified by suitable modelling or type testing at the design stage, since operational testing might not be practical or achievable. Examples of such modelling and testing activities include:

— wave load impact on conductors;

— slam closure rates for SSSV's;

— establishing performance requirements of anticipated casing design, where it is undesirable to pressure test against a cemented shoe.

During the operational life cycle, periodic inspection of the physical condition of equipment may be performed to check for evidence of degradation. Modelling of the effects of the degradation may be considered.

5.10 Reporting and documentation

5.10.1 General

Data related to well design, construction, operation, maintenance and permanent abandonment should be maintained and accessible throughout the life cycle of the well.

The well operator should define:

— the information and records about a well which are necessary to be recorded and stored;

— personnel responsible for data collection and document management;

— the length of time that records are to be retained.

The well integrity record system should contain:

— a repository for data and provide access to data and documents for all approved users;

— a documented process and procedures for controlling and updating data and documents;

— data / document maintenance features to combat degradation and ensure software (where used) interchangeability.

5.10.2 Well integrity status reporting

The well operator should define the reporting requirements to monitor the status of well integrity. These may include, but are not limited to:

— routine reports issued on a predefined periodic basis (e.g. monthly, quarterly or annually) reflecting the well integrity activities and issues addressed;

— reporting on the identified key performance indicators (KPIs) (see 5.12.1);
— event-specific well integrity incidents and investigation reports;
— reporting to the government/regulator as required by local legislation.

The well operator should define the scope, recipients and requirements for acknowledgement of receipt of all such reports.

Topics covered in the reports may include, but are not limited to, the following:

— previous well reviews, or ad hoc well reviews;
— changes to the original boundary conditions;
— change in the well function;
— changes in the well fluid composition;
— change or possible degradation of well and well-related hardware;
— MOC notices;
— well deviations;
— well barriers;
— well integrity issues;
— scale or corrosion issues;
— wear and tear to hardware and equipment;
— accidental damage to hardware and equipment;
— equipment obsolescence;
— loss of barrier or containment;
— environmentally related changes;
— statutory or legislative changes;
— changes in local procedures and standards;
— advances in technology that may be implemented;
— changes to the design and/or design limits of equipment/material, e.g. latest manufacturer's bulletins or industry standards;
— repairs to, and replacements of, well components, from valve parts to complete work over;
— relevant equipment maintenance information in order to improve equipment technical specifications, reliability data and/or preventative maintenance intervals;
— changes to the well operating envelope, such as an MAASP review;
— risk register updates.

5.10.3 Well life cycle phase deliverables

At the end of each phase in the well life cycle, requirements for documentation, certification and verification shall be met to ensure that management of well integrity is maintained.

There are also instances, depending on the well operator's organization, of transfers of responsibility within a well life cycle phase. These instances have requirements regarding the stewardship of information and maintenance of the well integrity. The well operator should define these requirements within its WIMS.

5.10.4 Well handover process

The well operator should define the accountability and responsibility for the well during its life cycle and the well handover process requirements.

Well handover is the process that formalises the transfer of a well and/or well operating responsibility from one functional group to another and is endorsed by the use of related well handover documentation.

The process should define the relevant handover phases. The phases at which the well handover typically occur are at least at the following transitions:

a) well construction phase to well operational phase;

b) well operational phase to well intervention and workover phase, including maintenance or servicing, and back to well operational phase;

c) well operational phase to abandonment phase.

The well operator should record the well operating limits and WBE status in the well handover documentation. As a part of the well handover documentation (see Annex J), the well operator should have a current WBS, or similar method of documenting well barriers (see Annex F).

Handover documentation should include only those items that are appropriate and capture any changes in the well's configuration, operating limits and known hazards (see Annex J).

The well operator should nominate competent personnel to be responsible for preparing, verifying and accepting the well handover documentation. These persons should sign and date the documentation accordingly.

5.11 Management of change

5.11.1 General

The well operator shall apply a management of change (MOC) process to address and record changes to well integrity requirements for an individual well or to the well integrity management system.

5.11.2 MOC process

The MOC process should include the following steps.

a) Identify a requirement for change.

b) Identify the impact of the change and the key stakeholders involved. This includes identifying what standards, procedures, work practices, process systems, drawings, etc. would be impacted by the change.

c) Perform an appropriate level of risk assessment in accordance with the well operator risk assessment process (see Annex A). This includes:

— identifying the change in risk level(s) via use of a risk assessment matrix or other means;

— identifying additional preventive and mitigating measures that can be applied to reduce the risk level;

— identifying the residual risk of implementing the change/deviation;

— reviewing the residual risk level against the well operator's risk tolerability/ALARP acceptance criteria;

— updating the risk register accordingly.

d) Submit the MOC proposal for review and approval in accordance with the well operator's MOC system.

e) Communicate and record the approved MOC.

f) Implement the approved MOC.

At the end of the approved MOC validity period, the MOC is withdrawn, or an extension is submitted for review and approval.

NOTE If the change is permanent, its implementation ends the MOC process.

5.11.3 Dispensation from the WIMS

In the management of well integrity, dispensations are often employed, especially in the operational phase of the well life cycle, to manage deviations from the WIMS requirements.

The well operator should have a procedure that clearly specifies the process and approvals required for dispensations from the WIMS. Dispensations should be limited in time and, if extended, the well operator's dispensation process should manage the process and approval for such extensions.

In the event of barrier impairment, there can be instances when the risk of reinstating the original barrier arrangement is out of proportion to the risk of not implementing a repair. In such instances, and after re-evaluating the applicable performance standard using a risk assessment, continued use of the well may be undertaken using the revised performance standard.

Dispensations from the WIMS should be managed through the MOC process.

5.12 Continuous improvement

5.12.1 General

The well operator should include continuous improvement processes in the WIMS that would detail how the information and knowledge gained should be communicated to those responsible for the phase of the life cycle in which the improvement can be implemented.

The techniques and processes used to support the key elements of the WIMS described in 5.4 and any other elements defined by the well operator should be routinely monitored to ensure that they are effective.

Several methods may be employed to carry out such performance monitoring, including, but not limited to, the following:

— KPI monitoring;

— capture of lessons learned;

— a conformance audit programme.

These methods may be used to identify where aspects of the WIMS can be improved.

5.12.2 Key performance indicator monitoring

KPIs represent defined metrics associated with the elements of the WIMS described in 5.4, plus any other elements defined by the well operator.

Setting, tracking and regularly reviewing these metrics aids in:

— determining the effectiveness of the WIMS as currently implemented;

— identifying general trends regarding the reliability of the well stock;

— identifying general trends regarding the well integrity risk posed by the well stock.

The well operator should determine KPIs and a suitable review frequency that are appropriate to track the effectiveness of the WIMS. These should be based on metrics that are aligned to critical objectives of the WIMS. Examples are given in Annex K. This allows monitoring of both the performance of well integrity activities and their effectiveness in maintaining and improving integrity.

5.12.3 Lessons learned

During the life cycle of the well, improvements that can be made to processes, procedures, designs and equipment will likely be identified.

The well operator should establish a formal process for capturing and documenting such lessons learned, in order to aid in the continuous improvement process.

5.13 Auditing

5.13.1 General

The well operator should establish an audit process to demonstrate conformance with the WIMS. The audit reports should provide an indication as to which parts of the WIMS are functioning adequately, and which parts need further action.

5.13.2 Audit process

Each element of the WIMS should be the subject of an audit. The frequency of audits should be established by the well operator, or as required by local regulation.

Each audit should have clearly defined terms of reference focused on testing conformance with the WIMS and the effectiveness of meeting the objectives of the WIMS.

The audit objectives, scope and criteria should be agreed in advance.

The audit team leader is responsible for performing the audit, and should be independent from the work process being audited.

The resultant audit report should identify any observed deficiencies and make recommendations to address such deficiencies.

The well operator management team responsible for well integrity should review the audit recommendations, and assign and track progress on action items as appropriate.

6 Basis of design phase

6.1 Basis of design phase objectives

The primary objective of the basis of design phase is to develop a basis of design that meets the functional requirements of the well, while also creating and sustaining well integrity through the entire life cycle. The elements of this phase are detailed in Figure 3. This work should be performed by a competent team that understands and assesses the conditions that affect the planned well and the functional requirements of the well over its life cycle, in order to identify potential hazards and to define appropriate barriers that are capable of controlling or mitigating these hazards and associated risks.

The work should follow a structured process with specific requirements, such that well integrity is achieved through the whole well life cycle.

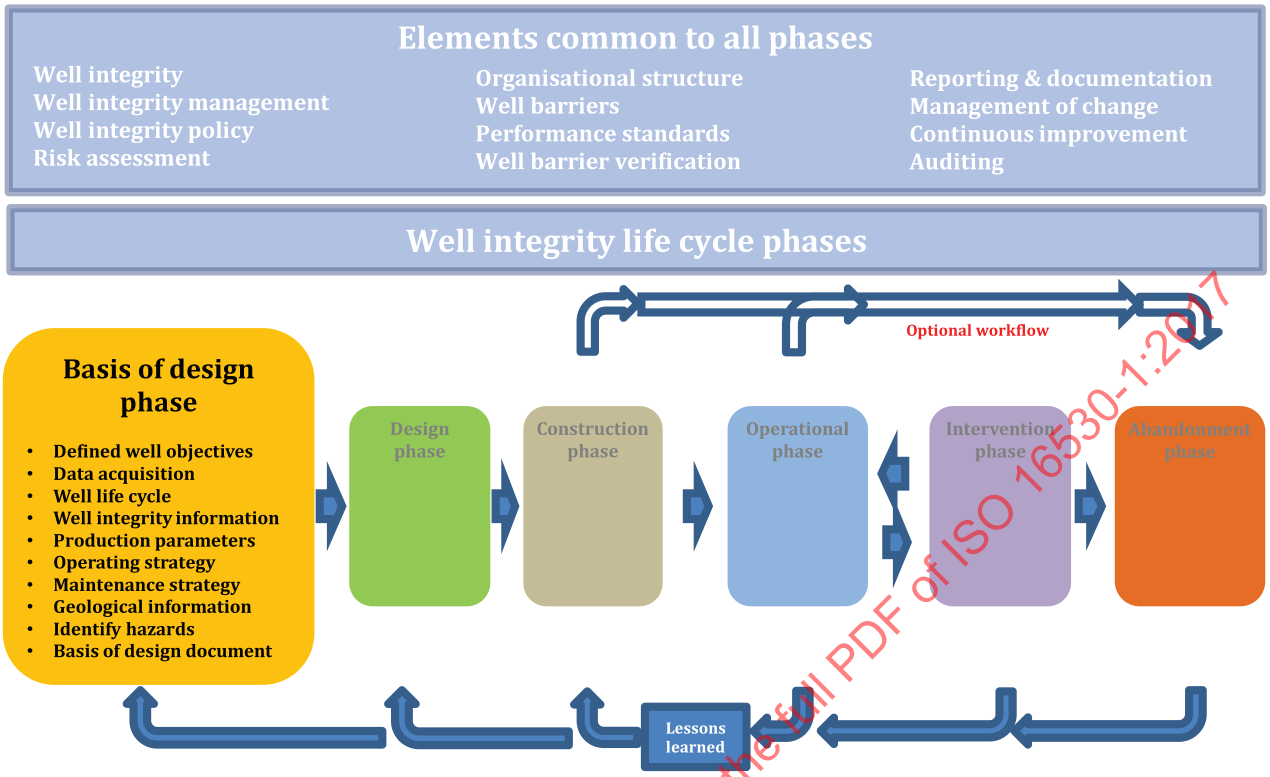


Figure 3 — Basis of design phase

6.2 Organizational structure and tasks

The resources and functional skills needed to carry out the basis of design phase should be defined to ensure sufficient time and competence levels for identifying the risks, hazards and appropriate mitigations considered over the life of the well. In most organizations, this task is addressed through collaboration among individuals with the relevant functional skills. The skill and experience levels required of the individuals depend on the particular challenges of the well.

Typical areas where functional skills are needed include the following:

— geology, geophysics, geochemistry, geomechanics, petrophysics;

— reservoir and production engineering;

— drilling, well testing, completion, subsea engineering;

— facilities, production operations;

— intervention, workover and abandonment activities;

— well maintenance/inspection and well integrity technical reviews.

Each general function may require further consultation with more specific sub-specialities in some applications (e.g. HPHT, environmental, deep-water and sour conditions).

The well operator should define the competence requirements and assign the appropriate personnel to undertake the following tasks:

a) define the well objectives, such as the subsurface target, and well type (producer, injector, gas or oil), life expectancy and productivity or injection capability with the anticipated effluent composition, and possible changes over the life cycle;

b) identify the anticipated rock mechanical and subsurface hazards that can threaten well integrity over the anticipated life cycle of the well, e.g. faults, fractures, pore pressures, temperature, H_2S, CO_2, solids production, shallow gas, high pressure stringers, chalks, moving salts, permafrost, subsidence, earthquakes;

c) provide any information pertaining to surface hazards and anticipated changes that can affect well integrity over the anticipated life cycle of the well, e.g. location, environment, urban planning, proximity to lakes, rivers, subsea, offshore, risk of ordnance, other operations or industrial activities, risk of subsidence, flooding;

d) identify the hazards associated with existing wellbores, abandoned wells, condition of the offset wells, related environmental issues, directional well path, etc.;

e) provide a combined hazard risk register from the identified and confirmed hazards for surface and subsurface conditions for the basis of design.

Typical sources of relevant input include:

1) offset wells, field operation history (downhole samples, formation pore pressures and strength, subsurface hazards);

2) local studies of surface and subsurface conditions (seismic, reservoir model, seafloor, topography, subsidence) that can affect well integrity during the life cycle;

3) lessons learned with respect to well integrity from other wells or projects in similar conditions;

4) anticipated life cycle changes or well operating limits that can affect well integrity.

The information should be used to outline the basis of design for the well to identify risks and associated hazards with respect to well integrity.

6.3 Well barriers

The well barrier assurance process in the basis of design phase consists of identifying potential hazards and defining appropriate barriers that are capable of controlling both subsurface and surface hazards over the well life cycle in accordance with the well operator's barrier philosophy and the requirements in this document.

A description of the system for well barrier monitoring, pressure management and the need for any chemical injection and inhibition should be included.

6.4 Hazard identification and assessment

A key objective of the basis of design phase is to identify the hazards related to well integrity. Annex L contains an example of a checklist to aid in the identification of potential hazards.

The level of detail should reflect this objective and, therefore, focus on identifying hazards that:

— represent a significant contribution to overall risk if the project is realized (i.e. potentially unacceptable risk);

— require control and mitigation through special attention and follow-up in the design phase to achieve an acceptable risk level.

The hazards identified should be captured and documented in a risk register.

6.5 Well integrity considerations for the basis of design

6.5.1 General information to be provided

The basis of design should contain the following information:

— project name;

— well location and target:

  1) latitude/longitude of all targets,

  2) target TVD depths;

  3) target formation information (name and type of formation);

— subsurface architecture (vertical/deviated/horizontal);

— well type (gas-lift, oil producer, water injector, gas producer, etc.);

— design pressures:

  1) maximum and minimum anticipated pore pressures over the well life cycle;

  2) formation fracture pressures or gradients;

  3) maximum expected wellhead pressures (flowing, shut-in or injection);

  4) maximum and minimum expected reservoir pressure over the well life cycle;

— production limits:

  1) maximum and minimum expected production rates (gas/oil/water);

  2) expected range of fluid type compositions to be produced or injected (e.g. sweet, sour, corrosive, solids content);

  3) strategy of stimulation/test/treatments and description of chemicals;

  4) expected surface and subsurface maximum and minimum temperatures;

— required well operating life, in years.

6.5.2 Well objectives and life cycle

Well objectives, and associated well integrity hazards over the well life cycle, should be defined by the drainage strategy, including any improved recovery methods. This includes a description of requirements for artificial lift, injectors for pressure support, any disposal wells and any anticipated changes or uncertainties during the well life cycle.

Activities needed to be performed in the well over its lifetime should be defined. This could be planned recompletion, conversion of producers to injectors, re-use of well by side-tracking, deepening to new targets, and changes in objectives, planned logging and intervention activities, etc.

6.5.3 Inflow requirements

Inflow aspects of the well that could influence well integrity should be included in this part of the basis of design, for example:

— Upper completion type: this should state if the well is a single or multi-string completion. A conceptual completion schematic/sketch may be included (as part of the supporting documentation).

— Lower completion type, e.g. cemented, mono-bore, open-hole.

— Sand control: sand failure assessment documentation should be included as part of the supporting documentation. If sand control is required, the methods of sand management should be included at this point. This may include screen selection, gravel selection, clean-up strategy, deployment strategy, etc.

— Perforation: if perforations are required, the target intervals should be provided at this point.

— Any zonal isolation requirements due to different reservoir parameters or pressure regimes.

6.5.4 Outflow requirements

Aspects of the well outflow that influence production should be included in this part of the basis of design, such as:

— flow requirements for production/injection;

— recompletion requirements over the lifetime of the well to accommodate changes in flow regime;

— requirements for chemical injection and/or artificial lift.

6.5.5 Well location and targets

The well location and targets should be described. This includes description of different locations and targets, with their associated identified hazards, as well as any expected changes during the life cycle. The well location should include the surface location, i.e. pad size, platform configuration, slot location and subsea topography.

6.5.6 Prognoses regarding geological formations, pore pressure, formation strength and temperature

A description of the expected formations and fluids, pore pressures, formation strength and temperatures to be encountered, including their uncertainty, should be provided. Annex M provides an example of a plot of pore pressure versus formation strength. The level of detail depends on well type and complexity.

The information should cover subsurface aquifers and hazards, faults and high pressure stringers, i.e. pore pressure prediction, freshwater zone protection, stratigraphic prognosis, well orientation and length of penetration through production zone.

6.5.7 Data acquisition requirements

The requirements for well integrity data acquisition during the construction and operation phases should be outlined in this part of the well basis of design. This should include:

a) identifying data acquisition requirements during the construction of the well;

   This should indicate what data are required during construction for each well section, and specify whether a cement evaluation log, an extended leak-off test, a saturation log, gamma ray logs, etc., are required.

b) identifying data acquisition requirements during the operation of the well, related to monitoring of barrier performance.

This should indicate what data are required over the lifetime operation of the well, and should specify whether fibre optics, downhole pressure gauges, control sensors, etc. are required as part of the well design.

6.5.8 Other considerations for well integrity

Other information may be required to ensure that the well design provides the required isolation, systems for maintenance and condition monitoring of the well barriers, as well as the well barriers for future abandonment. This includes information pertinent to the casing and completion design. Special considerations that are taken into account should be captured here, for example:

— any requirements for maximum and minimum well operating limits;

— well integrity isolation requirements related to identified risks, e.g. minimum formation strength at packer setting depth to avoid risk of out-of-zone injection, ground water isolation requirements;

— any SCSSV requirements, such as setting depth, due to e.g. the risk of hydrate and solids deposition;

— reservoir compaction and stresses that can affect integrity, such as shifting clay or salts, moving permafrost, other tectonic movement or subsidence risk;

— cementing and casing requirements to protect against corrosive aquifer and external corrosion protection of surface casing;

— special considerations that can affect barrier design, e.g. artificial lift, single-barrier wells;

— cementing requirements, including minimum casing and plug cement heights and logging requirements, as well as the remedial cementing strategy;

— local regulations affecting well design;

— requirements and available systems for well barrier monitoring and monitoring of parameters affecting well integrity (sand production, H_2S content, pressure, temperature, scale, paraffin , etc.);

— intended operating and maintenance philosophy;

— cap rock thickness and depth relative to top of cement column;

— time to gain access to the well.

6.5.9 Production and injection characteristics affecting well integrity through the life cycle

All data should be listed that are pertinent to the operation of the well over its lifetime. A life cycle production forecast, production profile and/or injection rates/profiles should be included. Any production parameter information that could affect the well integrity should be included, for example:

— expected flow/injection rates for oil/gas/water and their expected ratios;

— deposits likely to occur in the well, such as scale, wax, asphaltene, hydrates, NORM, mercaptan, mercury, etc.;

— expected microbial-induced corrosion;

— anticipated produced fluid composition, e.g. H_2S, CO_2, solids;

— anticipated injection fluid composition, e.g. oxygen, sulfate, solids content.

6.6 Quality assurance and approval process

There should be a cross functional quality assurance process that approves the final basis of design with documented assumptions and defined data origins.

6.7 Deliverables

The deliverables of this part of the well life cycle are the basis of design with the supporting risk register.

The basis of design should contain the documentation required for detailed design as described in 6.5. The risk register should be attached and the main hazards highlighted. An example of a risk register template is found in Annex B.

Well design options should be clearly identified, described and evaluated. As part of these options, robust well design and well integrity management through the life cycle should be especially taken into consideration (see 7.3).

7 Well design phase

7.1 Well design phase objectives

At the well design phase, consideration should be given to well integrity over the well life cycle, including any future interventions and well abandonment. The well should be designed so that the well integrity can be managed for the life cycle of the well. Well integrity aspects of the design should be focused on managing the hardware and systems that make up the well barriers for the life cycle. The input to the well design phase is the "basis of design" document from the well basis of design phase, together with the supporting risk register. The risk register should be updated in the well design phase as the risks are addressed. The elements of this phase are detailed in Figure 4.

It is recommended that the well operator perform a review of the well design to ensure that all identified hazards, risks, controls and mitigations have been addressed.

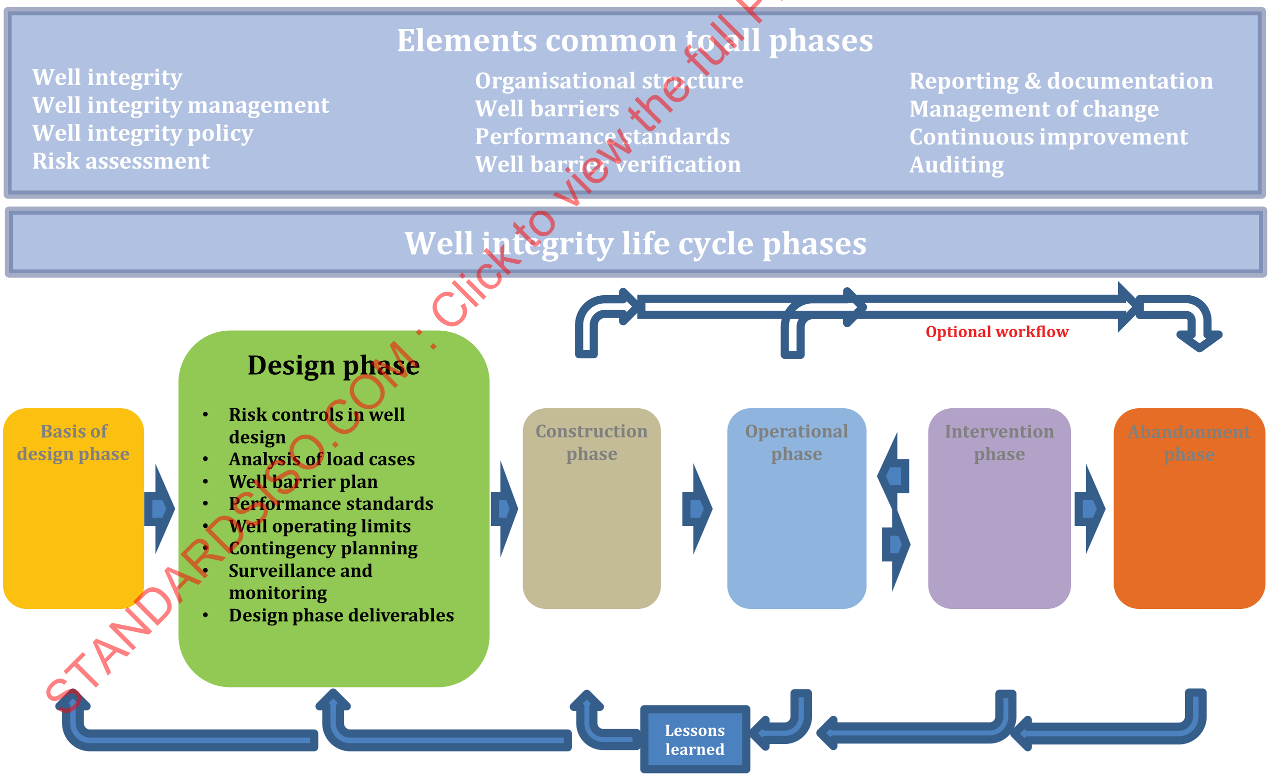


Figure 4 — Well design phase

7.2 Organizational structure and tasks

The well operator should define the minimum well integrity competence requirements and qualifications of personnel utilized to accomplish the requirements of the well design phase.

Typical examples of functional skills that are needed include the following:

- drilling engineering;
- well-testing engineering, completion engineering, subsea engineering;
- geology, geophysics, geochemistry, geomechanics, petrophysics;
- reservoir engineering;
- production engineering;
- risk assessment and management;
- well integrity engineering;
- fluids engineering (e.g. drilling, completion, packer, cementing fluids).

The well operator should define the competence requirements and assign appropriate personnel to fulfil the following tasks within the well design phase;

- casing design;
- completion design;
- analysis of pore pressures and rock mechanics;
- drilling and completion operations;
- well testing operations;
- well design risk management;
- material selection including corrosion and erosion analysis;
- load case analysis;
- specification of well and completion equipment;
- design and installation of well barriers;
- flow assurance;
- control and telemetry design;
- data acquisition design;
- well life cycle considerations;
- subsea design, including wellhead fatigue (if required);
- cementing design;
- abandonment (see Clause 11).

NOTE See ISO/TS 17969.

7.3 Risk controls in well design

7.3.1 Risk register

The risk register from the basis of design phase summarizes the hazards identified in the basis of design document. Additional hazards may be identified during the well design process. All these hazards, and their associated risks, should be addressed and mitigated, as required, in the well design phase. An example of the risk register can be found in Annex B.

The risk register is updated during the design phase.

7.3.2 Lessons learned

Often valuable information and insight can be gained by analysing previous wells and especially the problems encountered in establishing and maintaining well integrity throughout the life cycle. Consideration should be given to creating a formal process in order to capture these lessons learned and feedback the information into the design phase for new wells.

7.3.3 Well life cycle risk considerations

The design phase should consider risks associated with activities that may be performed during the well life cycle that affect well integrity. This includes designing for identified hazards in order to reduce the risks to an acceptable level such that the well is fit for its intended purpose throughout its life cycle.

Activities and risks to be considered include, but are not limited to:

— future intervention to conduct well integrity remediation: frequency, type, deck loading, crane capacity, well trajectory, BOP loading of subsea wellheads etc.;

— well suspension;

— change of use (e.g. conversion of producer to injector, introduction of gas lift, installation of ESPs);

— well monitoring and surveillance:

  1) annulus and production/injection tubing monitoring (e.g. temperature, pressure, fluid sampling);

  2) surveillance frequency;

  3) assessment of well barrier(s) condition using downhole logging techniques (e.g. MFL logs, calliper surveys);

— annulus access on subsea wells;

— need for inhibitor injection, glycol injection;

— hydrate controls;

— well activities leading to casing wear;

— risk of trapped annulus pressures in subsea wells;

— risk of wellbore collision while drilling in the proximity of neighbouring wells;

— risk of fracturing into adjacent, abandoned or legacy wells, either while injecting or during stimulation;

— risk of imposed high pressure from activities in adjacent wells;

— risk of fracturing into unplanned zones, cap rock or cement;

— risk of subsidence or compaction of the formation due to production;

— future abandonment.

Annex L provides an example of a hazard checklist.

7.3.4 Additional considerations during well design

7.3.4.1 General

The design phase should consider factors associated with the well's surroundings that can influence the well integrity for the duration of the well life.

7.3.4.2 Corrosion and erosion mechanisms

Consideration should be given to the following corrosion and erosion risks and the implementation of life cycle control measures to mitigate them as appropriate:

— internal oxygen-related corrosion;

— CO_2 corrosion;

— H_2S corrosion;

— stress cracking, for example caused by bromide mud, thread compound, chloride or H_2S;

— microbial-induced corrosion (MIC);

— sand/solids production;

— acid corrosion (e.g. from stimulation fluids);

— compatibility between components (e.g. galvanic corrosion, chemical reactions between elastomeric materials and completion fluids);

— formation of emulsion, scale, wax and hydrate deposits;

— other chemical corrosion.

Corrosion, erosion and fluid compatibility models can be used to assess the level of risk posed by the well fluids to all WBEs, and should form the basis of material selection and of methods of control for the produced fluids, injection fluids, artificial lift fluids, control line fluids, completion / packer fluids and production chemicals.

For each well barrier element, the well operator should establish and document acceptable limits of erosion. Such limits should be based on the preservation of well integrity for the defined well life-cycle load cases. Flow and velocity limits should be stated in the well operating limits (see 7.5), should be based on the forecast wellbore fluid composition and solids content, and should be set in accordance with ISO 13703, NORSOK P-001, DNV RP 0501, API RP 14E or by applying similar standards / techniques.

7.3.4.3 External and environmental hazards

Consideration should be given to the following external and environmental risks and the implementation of life cycle control measures to mitigate them as appropriate:

— external corrosion of structural components due to atmosphere;

— external corrosion of structural components due to marine environment;

— external corrosion of casing due to corrosive aquifers;

— fatigue of structural components due to mechanical cyclic loading;

— fatigue of structural components due to wave motion loads;

— fatigue of subsea wellhead due to drilling or intervention activities;

— point loading from non-uniform loads;

— impact of cyclic/thermal loading on strength of soil supporting the well;

— external loads on wells as a result of seismic activity, or movement of faults;

— compaction/subsidence loads;

— formation induced shear or collapse;

— mechanical structural damage as a result of dropped objects;

— mechanical structural damage associated with collisions (e.g. ships or vehicles);

— sabotage, wilful damage or theft.

7.3.4.4 Analysis of load cases

The well operator should consider the effects of various individual and combined loads on the components that make up the well. The well should be designed to meet all anticipated loading scenarios throughout the well life cycle.

Parameters to consider may include, but are not limited to:

— internal pressure;

— external pressure;

— temperature;

— tension;

— torsion;

— impact;

— bending;

— vibration;

— compression;

— wave and current loads;

— fatigue loads as a result of cycling:

  1) pressure cycling;

  2) temperature (thermal) cycling;

  3) wave cycling;

  4) bending moment cycling;

— point loading from non-uniform loads;

— formation induced shear or collapse.

The well operator should consider the following activities and load scenarios that can occur throughout the well life cycle:

— drilling;

— completions;

— production;

— flow potential;

— pressure testing;

— evacuation of tubing/casing;

— injection;

— well kill;

— well intervention;

— well stimulation;

— well suspension;

— well abandonment.

7.4 Well barriers

7.4.1 General

Well barriers should be defined for the well life cycle in accordance with the recommendations of 5.7.3.

The well barriers for the well life cycle include:

a) well barriers that are needed during each stage of the well construction process, as described in the well barrier plan;

b) the final well barrier system that is constructed, verified and handed over for the operational phase of the well life cycle;

c) well barriers that are in place during well intervention;

d) well barriers that are needed during final well abandonment;

e) well barriers remaining after well abandonment.

Additionally, well barriers should be designed to:

— meet the requirements for the life cycle phases (for outflow and zonal isolation) for all potential sources of inflow during the entire life cycle, including abandonment;

— prevent the development of sustained casing pressure (SCP) over the well life cycle;

— prevent contamination of any aquifers from wellbore by produced or injected fluids over the well life cycle;

— prevent undesired fluid communication between any distinct zones;

— meet all applicable regulatory requirements;

— adhere to applicable industry standards;

— prevent unintended movement of fluids within the well;

— be verifiable.

7.4.2 Well barrier plan

The design phase should include a barrier plan for the well construction. The barrier plan identifies the barriers required to prevent unplanned flow during each stage of the well construction phase.

The barrier plan should include well barrier schematics illustrating the barriers for each stage of the construction.

The well barrier plan should define the following:

— number of well barriers at each construction stage;

— well barrier elements (WBEs) required to be in place in the planned constructed well;

— well barrier schematic for each casing stage;

— cementing requirements to achieve zonal isolation and/or structural integrity;

— minimum shoe strength as per plan for each casing stage;

— production packer setting depth and/or other WBE setting depths;

— WBE-specific acceptance and test criteria, including testing, verification and suitable modelling;

— monitoring method(s) for the WBEs;

— final well barrier schematic (WBS).

7.4.3 WBE design performance standards

The well operator should define well design performance standards for the WBEs. Performance standards are a set of specifications and qualification criteria that allows the well operator to define, design, procure and establish verification requirements for all the individual WBEs, including cement, that make up the well barriers. This is intended to ensure that each WBE, once installed, meets all load and test requirements, and that the well is designed in accordance with the well operator's standards. The performance standards stipulate function and acceptance requirements, and are used to qualify equipment and hardware to be used in the well construction process.

The following are examples of types of requirements described in well performance standards:

— Component wear and tear allowances over the well life cycle, including wear during well construction.

— A defined set of specification criteria at component level, for example:

a) casing connection qualification testing;

b) material corrosion and erosion resistance test requirements;

c) function test requirements;

d) cement qualification testing;

e) time-to-closure for actuated valves; and

f) slam-closure flow rate requirements for an SSSV.

— Cementation fluids and consumables, such as thread compound, grease and consumables used in connections, valves and other hardware components.

— Qualification requirements for well components and well barriers in the construction phase, for example specifying when and where cement bond logs may be run.

— SCSSV design requirements, so that the control line actuation pressure ensures fail-safe closure in the event of wellhead failure, and which should take into account the hydrostatic column of the annulus fluid and the seawater (when relevant) above the wellhead. This becomes particularly relevant the deeper the valve is set and for wells in deep water.

The levels of QA/QC requirement for different well components, equipment or processes should reflect the level of risk identified for the well. An example for a tree can be found in ISO 10423 PSL matrix .

Performance standards should be developed over time as the project definition develops and as risk and hazard studies are conducted to demonstrate the level of performance necessary for each WBE to perform its role. The WBE performance standards should be fully established by the end of the well design phase, and are one of the outputs of the design phase of the well life cycle.

An example of WBE design performance requirements is given in Annex N.

7.4.4 Verification of the final well barrier

The well program should specify the testing and verification methods for the final well barriers and WBEs in accordance with design performance standards.

7.4.5 Emergency shutdown related safety systems

The well operator should define the well components that:

— are part of any emergency shutdown (ESD) safety system;

— are to be defined as SCEs; and

— are elements of a well barrier.

The components that are defined as safety-critical elements (SCEs) and/or are part of an ESD safety system are often raised to a higher level in maintenance frequency, traceability and reporting hierarchies. The well operator should define how these well components are managed and verification-tested over the well life cycle. The ESD components are often an integral part of a larger installation-wide shut-down system.

Typically, the following well components form part of an ESD system:

1) hydraulic wing valve;

2) hydraulic master valve;

3) SCSSV;

4) annulus safety valve;

5) actuated gas lift wing valve.

A cause-and-effect diagram, or matrix, is typically used to represent the interaction of different ESD systems working as a whole. This matrix is defined at the well design stage. Table 1 shows an example of a cause-and-effects matrix.

ESD systems should be related to the overall well hook-up and the consequence of failure, i.e. the production pipeline rating or the flare knockout vessel capacity, which should influence the closure time and function of any ESD valve, which would be defined as an SCE. Performance requirements for ESD systems should be in accordance with ISO 10418.

Table 1 — Example of a cause-and-effects matrix

	Well shut down components								
	Surface safety valve flow wing	**Upper master gate valve (UMGV)**	**Subsea TIV (tree isolation valve)**	**Sub-surface safety valve**	**Gas-lift shut down valve**	**Steam injection Shut-down valve**	**Beam pump / ESP shut-down**	**Gas blanketing shut down valve**	
Emergency shutdown level 1	1		1			1			Closure sequence examples
Emergency shutdown level 2	1	2			1		1	1	
Emergency shutdown level 3	1	2		3					
Example closure times	30 s	30 s	60 s	30 s after (UMGV)	30 s	30 s		30 s	

7.5 Well operating limits

The well operating limits comprise a list of parameters and their maximum and minimum values permitted during the operating phase of the well life cycle. The well start-up and shutdown procedures should include the well operating limits. The planned well operating limits are one of the outputs of the well design phase.

The well operating limits are defined as the combination of parameters within which the well should be operated to ensure that all component specifications, including their applicable design or safety factors and performance standards, are not violated.

These well operating limits, including MAASP, should form part of the future well operation plan and include defined limits for the parameters listed in 9.4.3.

7.6 Contingency planning for well construction

The design phase should verify that well integrity is maintained for planned contingencies. Each contingency should also include verification and assurance of well barriers.

Contingency plans may include an alternative well design, if a planned and constructed well barrier cannot be verified.

7.7 Surveillance and monitoring requirements

The requirements for the hardware and software for planned well integrity monitoring and surveillance (see 9.4) should be defined and specified at the well design phase. These requirements should be one of the outputs of the well design phase.

The hardware required and installation procedure should be described in the well programme. This may include, but is not limited to:

— annulus pressure monitoring systems;

— access to the well for future intervention for surveillance activities;

— downhole sensors and gauges.

7.8 Well design deliverables, reporting and documentation

Well design deliverables to the well construction phase should include, but are not limited to, the following:

— detailed well programme, including:

  1) well schematic;

  2) operational procedure;

  3) defined depths for casing shoes;

  4) defined depths for any packers, SPMs, SSSVs and other items;

  5) pore pressure chart and geological information (see Annex M);

— equipment specifications;

— updated risk register;

— well barrier plans, including well barrier schematics;

— planned well operating limits;

— design performance standard(s) with verification requirements;

— surveillance and monitoring hardware and software specifications.

8 Well construction phase

8.1 Well construction phase objectives

The well construction phase defines the required elements to be constructed and verification tasks to be performed in order to achieve the intended design. It addresses any variations from the design which require a revalidation against the identified hazards and risks.

The elements of this phase are detailed in Figure 5.

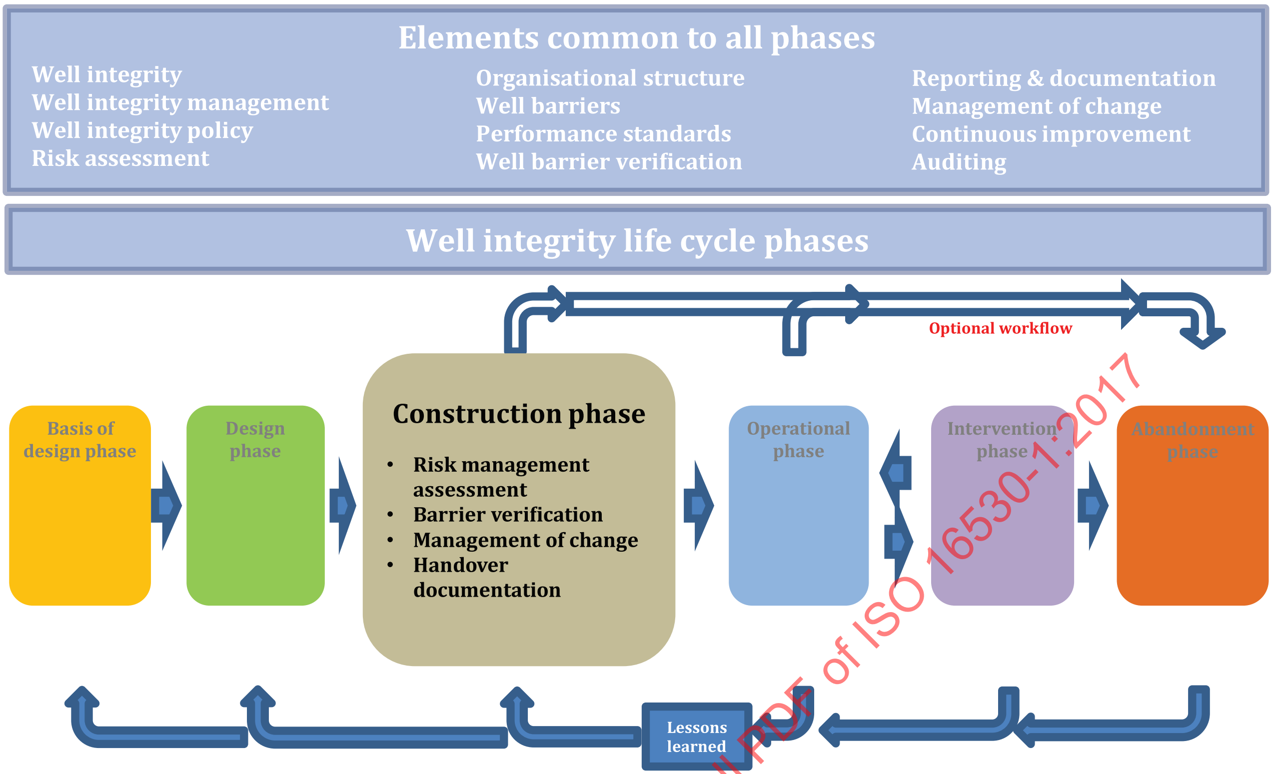


Figure 5 — Well construction phase

8.2 Organizational structure and tasks

The well operator should define the minimum well integrity competence requirements and qualifications of personnel utilized to accomplish the requirements of the well construction phase.

Typical examples of functional skills that are needed include the following:

— drilling engineering;

— well-testing engineering, completion engineering, subsea engineering;

— geology, geophysics, geochemistry, geomechanics, petrophysics;

— reservoir engineering;

— risk assessment and management;

— well integrity engineering;

— fluids engineering (e.g. drilling, completion, packer, cementing fluids);

— directional drilling control and measurement;

— well site supervision.

Each function may require further consultation with more specific sub-specialities in some applications (e.g. HPHT, environmental, deep-water, and sour conditions).

The well operator should define the competence requirements and identify the appropriate personnel to fulfil the following tasks:

— pressure and inflow testing evaluation;

— formation strength testing (e.g. LOT, XLOT) and interpretation;

— logging and interpretation;

— cementing and cement evaluation;

— evaluation of fluids, hydraulics performance, quality control of fluids;

— assessment of encountered rock mechanical and subsurface hazards that can threaten well integrity, e.g. faults, fractures, pore pressures, H_2S, CO_2, shallow gas, high pressure stringers, chalks, moving salts, permafrost, subsidence, earthquakes, aquifers;

— confirmation and management of the hazards associated with existing wellbores, collision avoidance, direction control and assessment, abandoned wells, condition of the offset wells, related environmental issues, etc.;

— updating the risk register using the identified and confirmed surface and subsurface hazards.

NOTE See ISO/TS 17969.

8.3 Well programme

The well programme is developed in the design phase, and includes specific provisions for installation and verification of well barriers during well construction. Non-conformance or variations during construction should be addressed through MOC.

8.4 Well barrier schematic

During well construction, the well barrier schematic (WBS) should be maintained, stored, and available for view at any time at the well site and office location. The WBS should be updated after the construction of each section of the well, thus reflecting the actual situation, and any changes should be properly documented.

8.5 Barrier verification

8.5.1 General

The manufacturing, maintenance, delivery and transferring of WBEs should be documented, controlled, validated and recorded as specified in 8.8. All WBEs should be accompanied by a quality file when delivered to the well construction site. The quality file should contain documentation verifying that equipment supplied meets the well design specifications. This documentation may include a manufacturer's pressure test certificate, test and inspection reports, design verification reports, an acceptance inspection certificate, and a statement of conformity. The statement of conformity should be stored and furnished in accordance with regulatory requirements.

All selected materials and equipment that will be used to establish a well barrier shall be verified against the well programme prior to installation in the well.

During the well construction phase the procedures within the well programme should be followed to ensure well integrity. When a WBE is installed, its integrity shall be verified in accordance with the requirements of the well programme (see 7.4.4 and 8.3) and a record of the verification should be maintained.

The following subclauses detail some specific considerations that should be addressed during construction.

8.5.2 Wellhead movement and fatigue

Wellhead movement should be monitored during construction and any changes documented. Movement includes, but is not limited to, growth, subsidence, tilt and twist.

Records should be kept of the data and assumptions used to determine the consumed fatigue life for wells subject to cyclic loading.

8.5.3 Cement

Cement is considered to be one of the critical well barrier elements (WBE), and in many cases is a common WBE. It is pumped and placed in a liquid state and allowed to harden *in situ*. This is reasonably unique as other well barrier elements (or their component parts) can often be tested prior to installation. Additionally, it is often difficult to repair or replace cement once it has been placed. These factors contribute to the critical nature of this particular well barrier element.

The following aspects of cementing can affect well integrity:

— drilling fluid and hole conditioning;

— centralization and casing coatings;

— slurry density and rheological control;

— lost circulation (ECD control);

— presence of corrosive/high salt content environment;

— cementing top plug landing practices and float equipment performance;

— post-cementing practices (e.g. setting before pressure testing, perforating requirements, stimulation, production, injection);

— temperature.

The cement should be evaluated in accordance with the requirements of the well programme. If the cementing operation was not implemented according to the requirements of the well programme, the well operator should consider using additional alternative verification methods for the barrier.

Indications observed prior, during and after the cementing operation that can impact the plan for establishing a competent barrier element include, but are not limited to:

— substantial loss of returns while pumping cement;

— significant deviation from the cementing plan, such as inability to maintain the desired density of the slurry, use of less than designed volume of slurry, etc.;

— premature returns of cement slurry to surface;

— lift pressure of the cement, measured just prior to bumping the plug, which indicates the top of cement (TOC) is not high enough in the annulus to isolate the uppermost potential flow zone;

— fluid influx prior to, during, or after cementing;

— excessive casing pressure;

— mechanical failure during the cement job, e.g. liner/casing, float collar and cement head failures;

— poor cement evaluation log results.

8.5.4 Casing shoe testing

As wells are constructed, a casing shoe test is typically performed after a string of casing has been cemented and approximately 2 m to 7 m (5 ft to 20 ft) of new hole has been drilled.

Casing shoe tests serve the following purposes:

— To confirm that the pressure containment integrity is sufficient to ensure that no flow path exists to formations above the casing shoe or to the previous annulus. If such a flow path exists and extends to a formation without adequate integrity, the seal around the casing shoe may require a repair (e.g. by cement squeeze).

— To test the capability of the wellbore to withstand additional pressure below the shoe, such that the well is competent to handle an influx of formation fluid or gas without the formation breaking down.

— To collect *in situ* stress data used for geomechanical analyses and modelling (e.g. wellbore stability).

— To enable the determination of the maximum allowable surface pressure for the next hole section.

Shoe tests may include formation integrity tests (FIT), leak-off tests (LOT), pressure integrity tests or pump-in tests (PIT) and extended leak-off tests (XLOT).

A record of the results of these tests should be documented.

8.5.5 Wellhead seal profile

The wellhead seal profile should be protected with appropriate isolation inserts (seal bore protectors) to prevent damage during the various construction operations. For example, during drilling, a wear bushing is inserted so that the drill string does not damage the sealing surface area of the seal bores.

8.5.6 Tubular connections

Specific procedures should be implemented to ensure proper tubular connection make-up as per manufacturer or relevant (ISO or API) specifications. These procedures should specify thread preparation and compound, required joint alignment or position, and optimum make-up values.

8.5.7 Casing wear

During well construction operations, especially in deep and/or deviated wells, rotating tool strings can cause internal wear of the casing that can result in reduced strength of the casing. Precautions should be taken to prevent such wear (e.g. use of non-rotating drill pipe protectors or hard banding) and the well plan should account for casing wear such that the worn casing meets the well design load requirements.

If it is anticipated that excessive casing wear has occurred, the casing should be checked for wear after completing operations in that string of casing (e.g. casing calliper log). Any observed wear in excess of the well plan can indicate a need to update well operating limits, design loads and MAASP.

8.6 Risk identification and assessment

A well shall be constructed taking into consideration the risks identified and documented in the design phase. These risks should be documented in a risk register for the well. Before commencement of well construction operations, identified control measures should be put in place and reviewed with the construction personnel. During construction, performance of the control measures and identification of additional risks should be continuously monitored to ensure competent barrier installation and the risk register should be updated.

8.7 Management of change

8.7.1 Potential changes to the well plan

If conditions encountered during well construction are significantly different than expected during design, the design shall be re-verified and/or revised to address these different conditions, using the required MOC process (see 5.11.2).

Any changes as a result of these reviews shall be properly documented, approved by the appropriate level of management, and included in the well barrier schematic, if appropriate.

The well's risk register should be updated to reflect any change in the level of risk based on the new conditions and changes to the well plan.

8.7.2 Suspended well considerations

During construction, well operations can be suspended for various reasons including technical, operational and safety considerations. When suspending a well, sufficient barrier(s) should be left in the well to prevent the uncontrolled flow of fluids at the surface or across subsurface formations while the well is suspended. Barrier selection should consider the anticipated period of suspension, the subsurface environment, the formations penetrated at the time of suspension and any specific conditions required for re-entry of the well at a later date.

8.8 Deliverables (reporting and documentation)

8.8.1 Well handover information

Well handover is the process that formalises the custody transfer of a well and/or well operating responsibility, and it is endorsed by the use of related well handover documentation.

The following well information should be included in the initial well handover documentation, from the construction phase to the operation phase:

— stack-up drawing of the tree and wellhead providing, at least, a description of the valves, their operating and test criteria (performance standards), test records and status (open or closed);

— SSSV status, performance standard and test records;

— status of ESD and actuator systems;

— well start-up procedures detailing production/injection rates and predicted pressures and temperatures;

— details of any WBEs left in the well (plugs, check valves or similar) or devices that ordinarily would require removal to allow well production and/or monitoring;

— detailed well barrier schematic, clearly indicating both primary and secondary well barriers and information about any well integrity issues;

— detailed wellbore schematic and test records (depicting all casing strings, complete with sizes, metallurgy, thread types and centralisers as well as densities of fluids left in the production string and annuli, cement placement, reservoirs and perforating details);

— pore pressure chart and geological information;

— detailed completion tally as installed (listing all component ODs, IDs, lengths, metallurgy, threads and depths);

— wellbore trajectory, including the wellhead surface geographical coordinates;

— pressures, volumes and types of fluids left in the annuli, wellbore and tubing and tree;

— well operating limits and MAASP calculations;

— subsea control system status and test records (if applicable).

Examples of well handover documentation and requirements are given in Annex J.

8.8.2 Risk register

After construction, the well's risk register should be updated to reflect any change in level of risk based on as-constructed information.

8.9 Continuous improvement

Lessons learned during well construction should be documented and all related well integrity issues to feed back into the well life cycle process should be captured (see 5.12).

9 Well operational phase

9.1 Well operational phase objectives

The well operational phase defines a pro-active well/field review, monitoring and maintenance process to ensure that the well is operated within the operating limits and to maintain integrity of the well barriers. Tracking changes in flow parameters, fluid composition, annuli pressure, corrosion or wear, ensures that these aims of the process can be achieved. The elements of this phase are detailed in Figure 6.

The main well integrity objectives of this phase are to:

— continuously monitor and ensure that wells are operated within their designed operating limits;

— maintain the well barriers and verify that they remain effective;

— manage well integrity anomalies and failures.

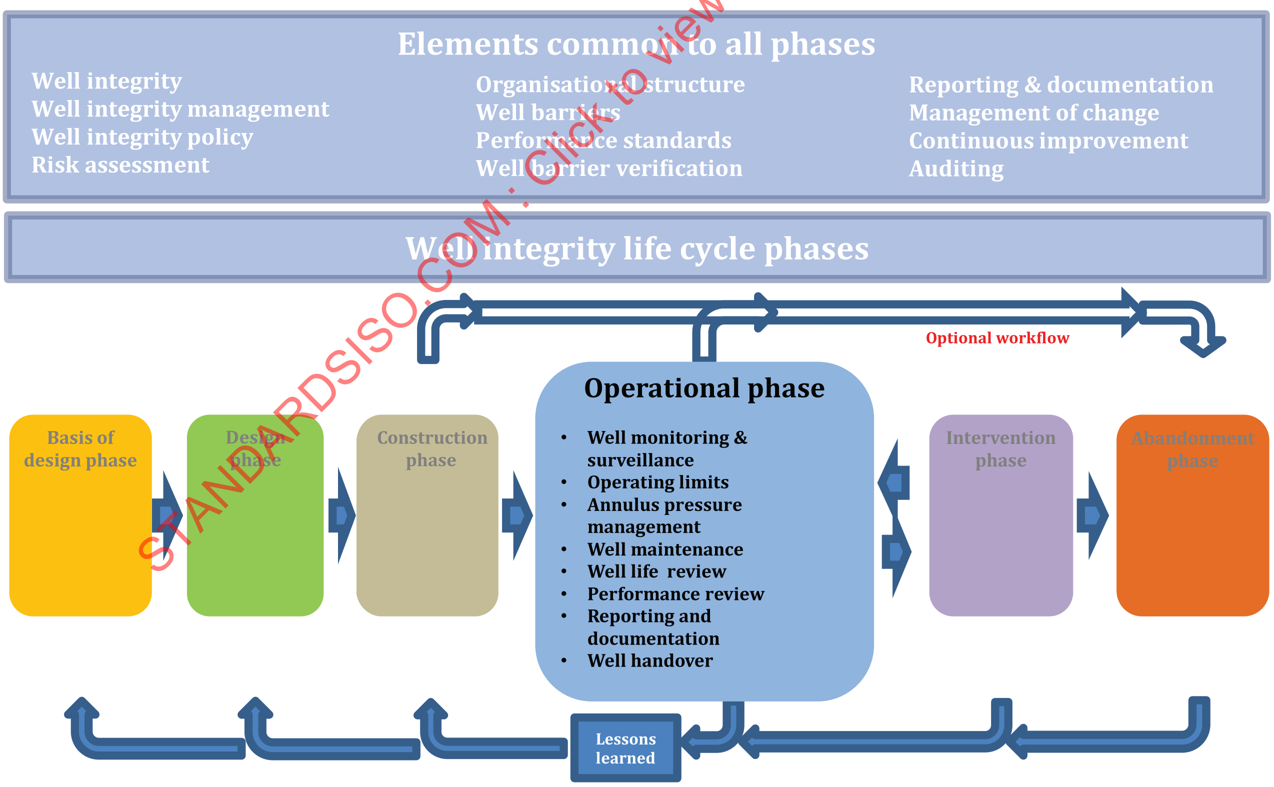


Figure 6 — Well operational phase

9.2 Organizational structure and tasks

The well operator should define the well integrity competence requirements and qualifications of personnel utilized to accomplish the requirements of the well operational phase.

Typical examples of functional skills that are needed include:

— well testing engineering, completion, subsea engineering;

— geology, geophysics, geochemistry, geomechanics, petrophysics;

— reservoir engineering;

— production engineering;

— well integrity engineering;

— fluids engineering (e.g. completion, packer, cementing fluids);

— risk assessment and management;

— well operations and maintenance;

— production chemistry.

Each function may require further consultation with more specific sub-specialities in some applications (e.g. HPHT, environmental, deep-water and sour conditions).

The well operator should define the minimum competence requirements and assign the appropriate personnel to fulfil the following tasks:

a) leak testing and evaluation;

b) sustained casing pressure evaluation and management;

c) fluids, hydraulics performance, quality control of fluids;

d) confirmation and management of the hazards associated with existing wellbores;

e) updating the risk register from the identified and confirmed surface and subsurface hazards;

f) updating well barrier schematics;

g) well operation, including start-up, monitoring and shutdown;

h) well maintenance, including preventative maintenance, testing, inspection, repair and replacement.

NOTE See ISO/TS 17969.

9.3 Well barriers

9.3.1 General

The well barriers should be verified during the well operational phase through monitoring and periodic testing. The wells should be operated within their defined operating limits, and their status documented.

9.3.2 Performance standards

At the end of the well design phase, the well operator should have defined performance standards, including performance verification requirements, for all WBEs specifically applicable to the operational phase. The performance verification requirements have associated acceptance criteria against which the well operator's operations and maintenance personnel should monitor, maintain, inspect, test and verify all WBEs throughout the operational phase.

At handover from the well construction phase, all WBEs should have been tested and verified according to the design performance standards and associated acceptance criteria, as described in 7.4.3, 7.4.4 and 8.5.1.

The performance standards may be continuously optimised throughout the operational phase based on lessons learned, while adhering to the well operator's MOC process.

The criteria to be determined for a performance standard are functionality, availability, reliability, survivability and interaction with other equipment, as described in 5.8. The criteria should be defined to ensure that the WBEs operate as was intended when the well was designed.

Examples of relevant verifications are:

— Measuring of stem travel and time to closure for actuated tree valves in order to verify functionality and availability. Function testing supplemented by valve inflow or pressure testing additionally demonstrates a valve's reliability.

— Testing of relevant transducers for the well's ESD system and their interaction with all relevant parts of the ESD system to ensure that all ESD valves will be activated to close as intended.

— Logging of wall thickness to ensure that erosion and wear allowances have not been exceeded and that the relevant component (typically tubing or casing) remains in conformance with the performance standard and, therefore, available.

— SCSSV function and inflow testing to demonstrate functionality, availability and reliability of the valve.

— Inflow testing of gas-lift valves to demonstrate functionality, availability and reliability of the valve.

— Monitoring and trending of annulus pressure(s). Sufficient differential pressure should be applied to be able to detect leaks across the relevant WBEs to be monitored (production packer, tubing or casing string, casing cement, etc.). Pressure testing of the annulus can be used to apply sufficient differential pressure and thus confirm pressure integrity.

— Pressure testing of hanger pack-off seals, utilizing a test port when available.

— Monitoring of chemical additives as defined in the basis of design.

— Monitoring of sand control systems.

— Fluid samples of annuli and reservoir stream.

Survivability is usually not verified by specific testing, but rather using qualification testing prior to installation (see 7.4.3) or modelling verification (5.9.6).

9.3.3 Leak rates

A large part of performance criteria is associated with the ability to contain well fluids. During the prolonged well operational phase, the occurrence of pressure build-up due to leaks in downhole WBEs is not uncommon. Applying a zero-leak-rate policy during this phase can prove to be unrealistic, and the well operator's performance standards may define an acceptable leak rate higher than zero for the various WBEs.

Using a risk-based approach, the well operator should define their acceptable leak rates and testing frequency for individual WBEs within the acceptance criteria described below. This may, for example, be accomplished by a risk assessment, which can also address the risk to the facility/installation when exhibiting such a leak rate, or pressure.

Acceptable leak rates should satisfy the following acceptance criteria, as appropriate:

— unplanned or uncontrolled leak of wellbore effluents to surface or subsurface environment: not permitted;

— leak across a well barrier element, contained within a well barrier or flow path: see ISO 10417 which defines an acceptable leak rate as 24 l/h (6,34 US gallons/h) of liquid of 25,4 Sm^3/h (900 scf/h) of gas;

— Leak across a well barrier to another well barrier not able to withstand the potential newly imposed load and fluid composition: not permitted;

— leak across a well barrier to another well barrier able to withstand the newly imposed load and fluid composition: see ISO 10417 for acceptable leak rates.

NOTE 1 For the purposes of this provision, API RP 14B is equivalent to ISO 10417.

The acceptable leak rate may be different for different WBEs; for example, an SCSSV flapper valve or gas-lift check valve may be allowed a higher leak rate than a tree master valve. These differing allowable leak rates can be catalogued in a matrix, which is referred to as the "leak rate acceptance matrix" (see Table 2 for an example) and may be included as part of a performance standard.

Table 2 — Example of a leak rate acceptance matrix

Acceptable leak rate matrix for:
Operator: XYZ
Field: ABC
Well type: producing wells
Other: closed in thp does not exceed 2,500 psi

Increasing allowable leak rate →

Operator to perform a risk based analysis to determine allowable leak rates for various barrier elements and for different well types.	Zero leak rate	API 598 > 3 cc or 0.025 scf / min per inch diameter	10 l/hr or 450 scf/hr	Leak rate as defined in ISO 10417 24 l/hr or 900 scf/hr
Hydraulic master valve (ESD)				
Lower master valve				
Hydraulic wing valve (ESD)				
Swab valve				
Kill wing valve				
Gas lift wing valve (ESD)				
Tree body				
SSSV				
Tubing plug in suspended well				
Bonnets, flanges and fittings				
Stem packings				
Instrument lines				
Control lines				
Tubing void				
Tree actuators & lines				
Wellhead voids				
A-annulus valves (normally open)				
A-annulus valves (normally closed)				
B-annulus valves				
C-annulus valves				
Installed VR plugs				
Tubing leak (sub hydrostatic well)				
Tubing leak (flowing well)				
Gas lift valves (sub hydrostatic well)				
Gas lift valves (flowing well)				
Production casing leak (sub hydrostatic well)				
Production casing leak (from 9-5/8" shoe)				
Intermediate casing leak				
Production packer				

Certain WBEs may require specialized testing with regard to monitoring and leak rate testing. These include, but are not limited to: safety and chemical valve control lines, wellhead voids and valve removal plugs. Leaks into or across these types of WBEs should be risk-assessed and mitigating measures put in place.

Leaks should be anticipated to occur at dynamic seals such as polished rod stuffing boxes or positive cavity pump rotary stuffing boxes. Where this type of leakage is expected, mitigating measures should be in place to capture, contain and safely dispose of the leaking fluids.

NOTE 2 The inflow testing of *in situ* gas-lift valves is difficult to measure and compare to the ISO 10417 leak rate. A description of how this can be rigorously performed, together with a suggested practical alternative, is included in Annex O.

Where verification testing reveals leak rates that exceed the acceptance criteria, these are to be managed as per 9.7.

9.4 Well monitoring and surveillance

9.4.1 General

The well operator shall define the monitoring and surveillance requirements to ensure that wells are maintained within their operating limits, and should document these requirements in the WIMS.

9.4.2 Monitoring and surveillance frequency

The well operator shall define and document the schedule, frequency and type of monitoring and surveillance required.

A risk-based approach may be used to define the monitoring and surveillance frequencies for WBEs based on the risk of loss of integrity of a WBE and the ability to respond to such loss of integrity (see Figure 7).

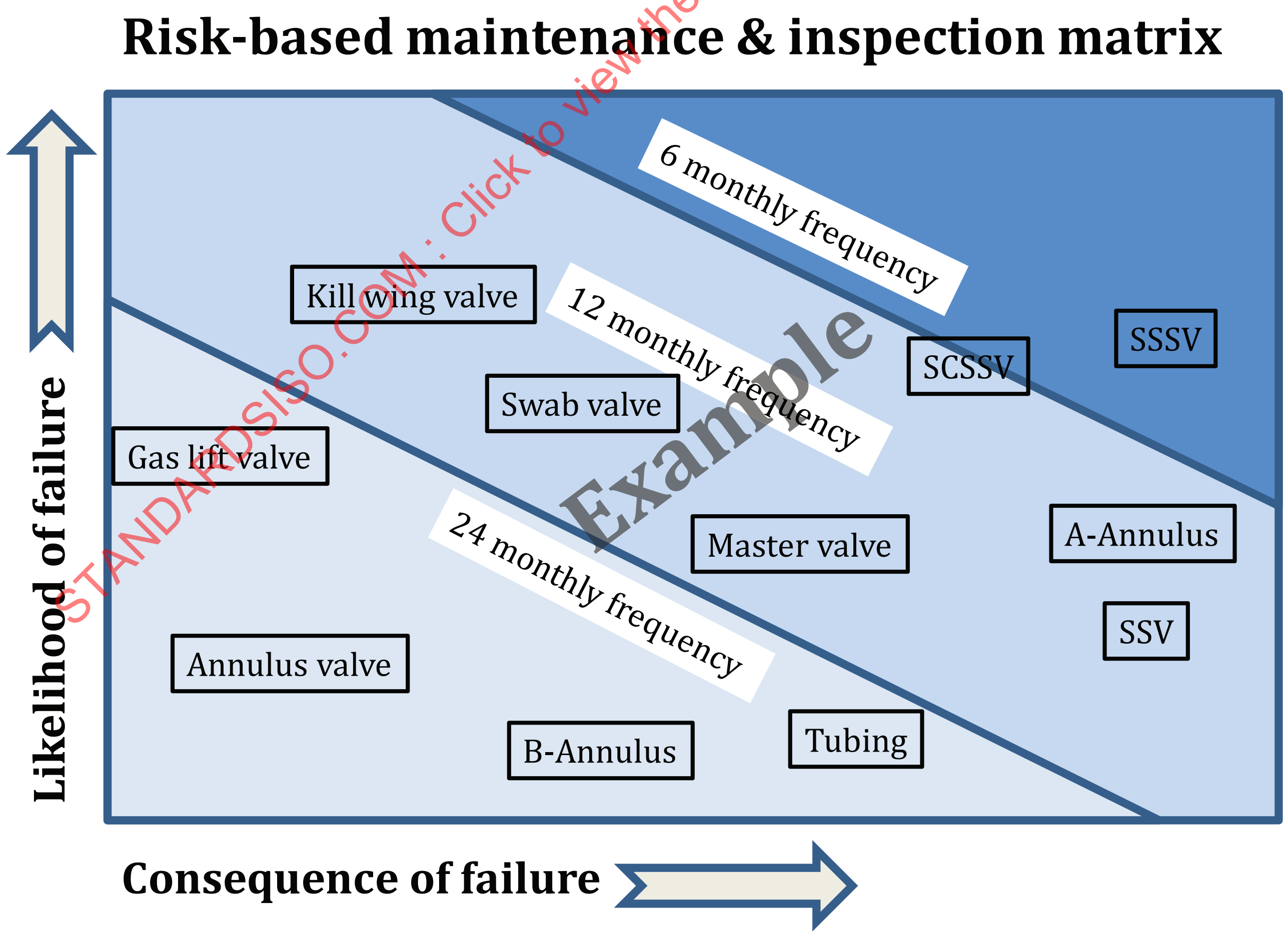


Figure 7 — Example of risk-based model as applied to well integrity assurance activities

Monitoring frequency may be adjusted under two scenarios:

a) if it is found that the monitoring and surveillance activities are resulting in a higher, or lower, than forecast number of non-conformances; or

b) based on risk considerations such as reliability or mean-time-to-failure analysis.

9.4.3 Well operating limits

The well operator shall identify the operating parameters to be followed for each well, or well type, and clearly specify the operating limits for each parameter. In the event that the well conditions change during the operating phase it should be confirmed that the operating limits are still applicable.

Any unplanned event that causes the well to be operated outside the operating limits should be the subject of an investigation to determine the causes and an assessment made for the continued operation of the well. These should be addressed in the reporting (see 5.10) and auditing (see 5.13) procedures.

Any planned deviation from, or modification to, the approved operating limits should be subject to an MOC procedure (see 5.11).

Operating parameters for which limits should be set may include, but are not limited to, the following:

— wellhead/tubing head production and injection pressure;

— production/injection flow rates;

— maximum allowable annulus surface pressures (MAASP) (see 9.5.6);

— annulus pressures, bleed-offs and top-ups;

— production/injection fluid corrosive composition (e.g. H_2S, CO_2 limitations);

— production/injection fluid erosion (e.g. sand content and velocity limits);

— water cuts and BS&W;

— operating temperature;

— reservoir draw-down;

— artificial lift operating parameters;

— control line pressure and fluid;

— chemical injection system parameters;

— actuator pressures and operating fluids;

— well kill limitations (e.g. limits on pump pressures and flow rates);

— wellhead movement (e.g. wellhead growth due to thermal expansion and wellhead subsidence);

— cyclic load limitations leading to fatigue life limits (e.g. for risers, conductor casing, thermal wells);

— allowable bleed-off frequency and total volume, per annulus;

— production of naturally occurring radioactive material (NORM);

— corrosion rates;

— tubing and casing wall thicknesses;

— cathodic protection system performance.

The well operator may also consider capturing wellhead and tree load limitations in the well operating limits, such as those associated with axial bending, lateral and torsional stresses applied during well interventions.

An example of a well operating limits form can be found in Annex P.

9.4.4 Suspended and shut-in wells

A shut-in or suspended well should be monitored according to a risk-based schedule defined by the well operator, with due consideration of the risk profile brought about by the change in flow-wetted and non-flow-wetted components, irrespective of whether the well is hooked up to production facilities.

9.4.5 Visual inspection

Visual inspection is undertaken to assess the general condition of the surface or mud-line equipment, as well as associated protection around the well.

The items to be considered for visual inspection include the following:

— physical damage to well equipment, barriers, crash frames or trawl deflectors;

— check well cellars clean and free of debris or fluid, including surface water, build-up;

— ancillary pipework (e.g. for pressure monitoring);

— general condition of the well head and tree: mechanical damage, corrosion, erosion, wear;

— observation of leaks or bubbles: leaks and a description of the leak should be reported in accordance with the well operator's spill reporting procedure or regulatory requirements.

9.4.6 Well logging

Well logging techniques are often the only means of evaluating the condition of some WBEs such as cement, casing, tubing, etc., either by measuring material quality and defects or by measuring flow-related phenomena.

These logging and surveillance techniques may be part of a pre-planned surveillance programme, or may be initiated in response to an event or an observed anomaly. Surveillance results from sample wells may be used as an input across wells of the same type in a field.

9.4.7 Corrosion monitoring

Corrosion of structural or pressure-containing components of the well can lead to a loss of well integrity.

A well is generally exposed to two distinct corrosion processes:

a) internal corrosion that originates from produced or injected fluids, drilling mud or completion brines; or

b) external corrosion that originates from contact with oxygenated water combined with chlorides, H_2S or CO_2, such as surface water, static subsurface water, sea water or aquifers.

Both internal and external corrosion can lead to structural integrity problems and a potential loss of containment, if not controlled or mitigated in a timely fashion. The well operator should define the monitoring programme and its frequency, based on the assessment of the corrosion risk to the structural and well barrier elements. The programme may be adjusted depending on the results of inspections performed.

Corrosion management programmes may include the following elements:

— selection of materials resistant to corrosion;

— estimates for corrosion rates for barrier elements over the design life of the well; such estimated corrosion rates should be based on documented field experience, or modelled using recognized industry practice;

— indirect measurements, such as sampling annulus or well fluid for corrosive chemicals (e.g. H_2S, acid) and by-products of corrosive reactions;

— monitoring of chemical injection into the fluid flow path;

— monitoring of chemical inhibition of annulus fluids;

— isolation of annuli from oxygen sources;

— cathodic protection;

— periodic examination of protective coatings (e.g. where accessible, to conductors, wellheads, trees) and of structural members, such as conductors and surface casing.

9.4.8 Corrosion monitoring and prevention – external

When wells are at risk due to corrosion from external environmental influences such as sea water, aquifers or swamps, the well operator shall assess the risk and define the means of protection. One method of protection that can be applied to protect bare steel components, such as casing and conductors, is a cathodic protection system.

The well operator should have an assurance system in place to verify that the protection system (where applicable) is operating in accordance with the design intent.

Further information on these systems can be obtained from NACE/SP 0169.

9.4.9 Erosion monitoring

The erosion of components in the flow path within the wellbore, wellhead and tree can lead to loss of well integrity.

Particular attention should be given to sections in the flow path where velocity and turbulence can increase, such as at changes in the cross-sectional area in the completion string, and in cavities within the tree assembly.

If there is any significant change in wellbore fluid composition or solid content, the erosion risk and velocity limits should be reassessed.

For wells that are operating close to the velocity limits, an erosion-monitoring programme should be established, and should form part of the well inspection and maintenance programme.

9.4.10 Structural integrity monitoring

The well operator should establish suitable systems to model or measure degradation in the structural members of the well.

In some instances, it is not possible to directly measure the effects of cumulative fatigue such as the appearance of cracks. A tracking and recording system may assist with the assessment of the predicted consumed life of the components.

The conductor, surface casing (and supporting formations) and wellhead assembly typically provide structural support for the well. Failure of these structural components can compromise well integrity and escalate to a loss of containment. For each well, the well operator should assess the risk of failure of such structural components.

Potential failure modes for structural components can include, but are not limited to, the following:

— metal corrosion;

— metal fatigue due to cyclic loads;

— degradation of soil strength due to cyclic, climatic and/or thermal loads;

— lateral loading due to shifting formations or earthquake.

Additional considerations of failure modes should be given to subsea and offshore structural components which are subjected to loads arising from temporary equipment attached to the well through the life cycle, such as drilling or intervention risers and BOPs.

9.4.11 Well elevation monitoring

Unexpected changes in well elevations can be an indication of the degradation of structural support of the well and can escalate to a level that impacts the well integrity.

Elevation monitoring and recording should form part of the well inspection programme (see 9.4.5). The top of the conductor and the wellhead relative to an established datum should be recorded (see Figure 8). Data should also include the wellhead temperature at the time the elevation measurement was taken. Depending on the well configuration, it can be normal for the well to "grow" when transitioning from a cold shut-in to a hot production condition.

When monitoring for subsidence or elevation of the well and its surroundings, the datum reference should be periodically verified and recorded to confirm that the datum has not moved.

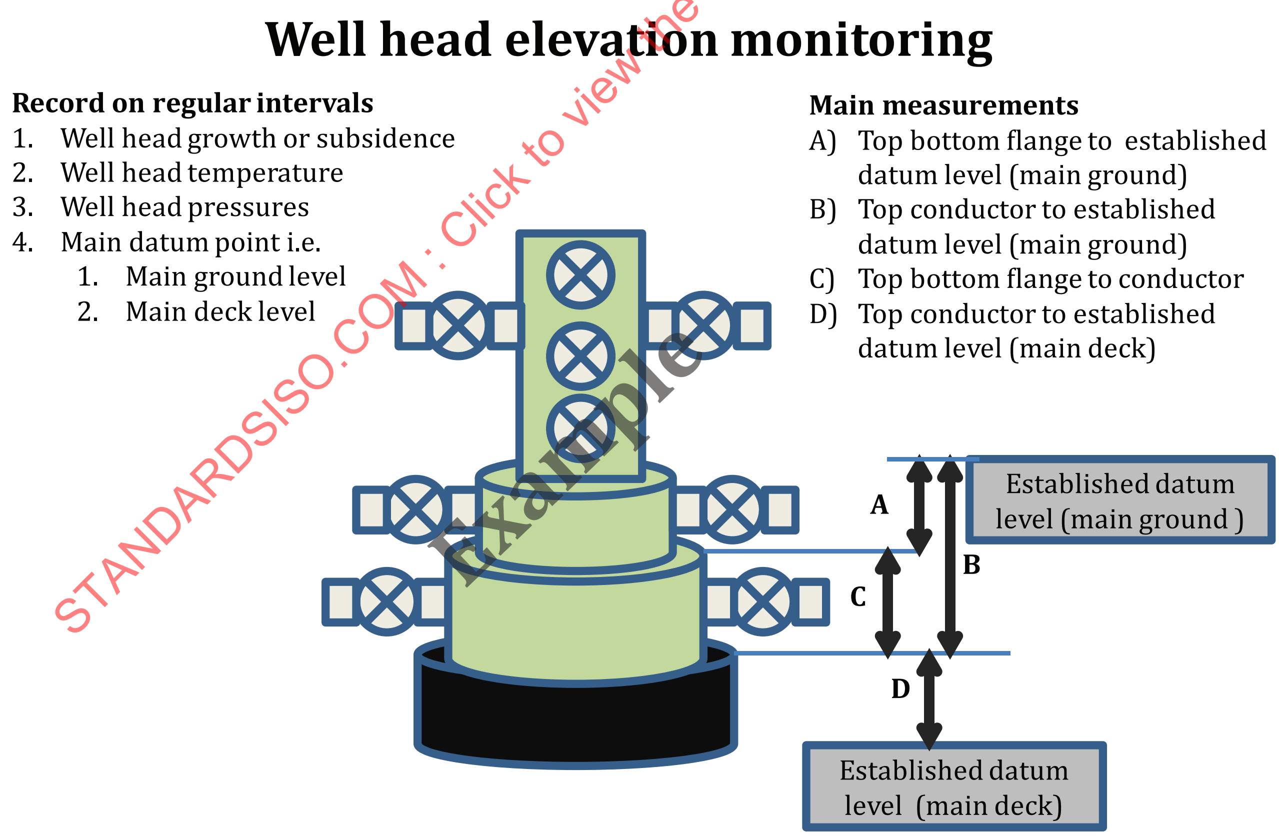


Figure 8 — Example of subsidence measurement

9.4.12 Reservoir subsidence

In some mature fields, depletion of reservoir pressure, or a reservoir pressure increase, or thermally induced permafrost melting, have led to compaction or elevation of the reservoir rock and/or subsidence of the overburden formation(s). Resultant changes in the tectonic stress regime can also activate faults. This has the potential to impose significant loads on casing strings, leading to casing failure. Also, the subsidence can undermine a platform or well pad.

The well operator should make an assessment of the potential for compaction and subsidence. Where it is assessed to be a risk, suitable monitoring programmes should be established.

Such programmes may include, but are not limited to, the following:

— surface measurements;

— downhole wellbore measurements;

— monitoring for downhole mechanical failures;

— monitoring for loss/reduction of production;

— seismic survey studies.

9.5 Annulus pressure management

9.5.1 Management considerations

The well operator shall manage the annuli pressures such that well integrity is maintained throughout the well life cycle.

It is advisable to consider at least the following when managing annulus pressure based upon a risk assessment:

— pressure sources;

— monitoring, including trends;

— annulus contents, fluid type and volume;

— operating limits, including pressure limits and allowable rates of pressure change;

— failure modes;

— pressure safety and relief systems;

— flow capability of any annulus with respect to a loss of containment;

— annulus gas mass storage effect (i.e. volume of gas between the annulus's liquid level and surface);

— introduction of corrosive fluids into an annulus not designed to resist such fluids;

— maximum potential pressure that can occur should a compromised barrier degrade further.

9.5.2 Sources of annulus pressure

Three types of annulus pressure can occur during the well life cycle, generally referred to as follows.

a) Well operator-imposed annulus pressure.

This is pressure that is deliberately applied to an annulus as part of the well operating requirements. Typically, this can be gas-lift gas in the A-annulus or pressure applied in the A-annulus in order to protect against collapse risk from trapped annulus pressure in the B-annulus on subsea wells.

b) Thermally induced annulus pressure.

This is pressure in a trapped annulus volume that is caused by thermal changes occurring within the well (e.g. well start-up and shut-in, due to neighbouring wells, increased water production).

c) Sustained casing pressure (SCP).

This is pressure which occurs in an annulus that rebuilds after having been bled off and cannot be attributed to either well operator imposed or thermally induced pressure. SCP can be allowed by design (e.g. wells completed with production casing, tubing and no packer) or be indicative of a failure of one or more barrier elements, which enables communication between a pressure source within the well and an annulus. If a barrier has been compromised, this by definition, means there is a loss of integrity in the well that can lead to an uncontrolled release of fluids, which in turn can lead to unacceptable safety and/or environmental consequences.

Communication with a pressure source can be due to one or more of the following failure characteristics:

— casing, liner, tubing degradation as a result of corrosion/erosion/fatigue/stress overload;

— hanger seal failure;

— annulus crossover valve leak in a subsea tree;

— loss of cement integrity;

— loss of formation integrity, e.g. depletion collapse, deconsolidation, excessive injection pressure, compaction;

— loss of tubing, packer and/or seal integrity;

— leaking control/chemical injection line;

— valves in wrong position.

NOTE 1 API RP 90 contains methods that can aid in the determination of the nature of the observed annulus pressure.

NOTE 2 Annex Q provides an example of possible well leak paths.

9.5.3 Annulus pressure monitoring and testing

The well operator should define a programme to monitor the pressures in all accessible annuli. Any change in annulus pressure, increase or decrease, could be indicative of an integrity issue. The regular monitoring of the well tubing and annuli during well operations enables early detection of threats to, or a potentially compromised, well barrier. For wells completed without a packer, a change in A-annulus pressure could indicate a change in the bottom hole pressure or the fluid level.

To effectively monitor annuli pressures, the following should be recorded:

— fluid types and volumes added to, or removed from, the annulus;

— fluid types, and their characteristics, in the annulus (including fluid density);

— monitoring and trending of pressures;

— calibration and function checks of the monitoring equipment;

— operational changes.

Where applicable, it can be useful to maintain a small positive pressure in the annuli, which should be different in each annuli, on sections equipped with pressure monitoring, such that leaks can be detected.

The well operator should define the need for annulus pressure testing, or integrity verification by other methods, when;

— changing the well functionality, i.e. from producer to injector well, etc.;

— there is a risk of external casing corrosion as a result of aquifer penetration;

— there is a lack of evidence from positive pressure monitoring.

9.5.4 Frequency of monitoring tubing and annulus casing pressures

The well operator should determine the frequency of monitoring and surveillance of tubing and annulus casing pressures.

Consideration should be given to the following items when establishing the monitoring frequency:

— expected temperature changes and effects, especially during start-up and shut-in;

— risk of exceeding MAASP or design load limits;

— risk of sustained annulus pressure;

— regulatory requirements;

— response time for adjusting annulus pressure;

— sufficient data for trending and detection of anomalous pressures;

— deterioration from corrosive fluids (e.g. H_2S and chlorides);

— operating characteristics of control/injection lines (e.g. chemical injection lines, size, operating pressure);

— annuli used for injection;

— changing the well function, i.e. from producer to injector well, etc.;

— risk of external casing corrosion as a result of aquifer penetration.

9.5.5 Investigation of annulus pressure

If an anomalous annulus pressure has been identified, records and well history should be reviewed to determine the potential cause(s) or source(s) of the pressure.

A bleed-down/build-up test performed on the annulus is one method to investigate the nature of an annulus pressure source. The well operator should establish a procedure for conducting pressure bleed-down/build-up tests. The influx of fluids due to sustained annulus pressure can contaminate the annulus contents; this should be risk-evaluated when performing bleed-down testing operations.

NOTE An example of a methodology for performing such tests can be found in API RP 90.

The process should include recording of surface pressures, and the volumes and densities of liquids and gases bled off or topped up in the annulus. These values are required to investigate sustained annulus pressure with a view to mitigating the subsurface risk of a loss of containment.

Additional information to establish the source of an anomalous annulus pressure can sometimes be obtained by manipulating a neighbouring annulus pressure. If it is possible to obtain fluid from the affected annulus, this can be assayed to identify the source of the fluid (referred to as “fingerprinting”).

9.5.6 Maximum allowable annulus surface pressure

9.5.6.1 General

The maximum allowable annulus surface pressure (MAASP) is the greatest pressure that an annulus is permitted to contain, as measured at the wellhead, without compromising the integrity of any well barrier element of that annulus. This includes any exposed open-hole formations.

The MAASP should be determined for each annulus of the well, and be re-determined if:

— there are changes in WBE performance standards;

— there are changes in the service type of the well;

— there are annulus fluid density changes;

— loss of tubing and/or casing wall thickness has occurred;

— there are changes in reservoir pressures outside the original load case calculation.

9.5.6.2 Calculation of MAASP

The following information is necessary to calculate the MAASP:

— maximum pressure to which the annulus has been tested;

— details of the mechanical performance specifications, or as-manufactured performance, of each component that forms the annulus;

— details of the as-constructed well;

— details of all fluids (density, volume, stability) in the annulus and in adjacent annuli or tubing;

— details of casing cementation, cement tensile and compressive strength performances;

— details of formation strength, permeability and formation fluids;

— details of aquifers intersected by the well;

— adjustments for wear, erosion and corrosion, which should be considered when determining the appropriate MAASP to apply;

— when pressure relief devices (e.g. rupture discs) are installed in a casing, assurance that MAASP calculations include all load cases for both annuli with the relief device open and closed;

— details of the SCSSV control line actuation pressure, to ensure that the MAASP does not prevent the SCSSV from closing in the event that a loss of SCSSV control line integrity results in hydraulic communication between the control line and the annulus.

Examples of MAASP calculations are found in Annex R.

The well operator should store MAASP calculations and assumptions in a data repository. MAASP values should be available on the well barrier schematic and well records.

9.5.6.3 Setting operating limits based on MAASP

The well operator should determine an operating range for each annulus that lies between defined upper and lower thresholds.

The upper threshold is set below the MAASP value to enable sufficient time for instigating corrective actions to maintain the pressure below the MAASP.

The upper threshold should not be so high that the pressure in the annulus can exceed the MAASP due to heating after shut-in. This is particularly relevant for an injector with cold injection medium, where any bleed-off activities are not prioritised in an emergency situation (e.g. ESD).

The following issues may be considered when establishing the setting for the lower threshold:

— observation pressure for the annulus;

— providing hydraulic support to WBEs;

— avoiding casing collapse of the next annulus (e.g. for next annulus or voids if it is not possible to bleed-off);

— avoiding hydrate formation;

— accounting for response time;

— ability to detect potential small leaks;

— variability of fluid properties;

— temperature fluctuations;

— avoiding vapour-phase generation (corrosion acceleration);

— preventing air ingress.

For subsea wells, it is recommended that the lower threshold be set above the hydrostatic pressure of the sea water column at the wellhead.

The principle of operating limits is illustrated in Figure 9.

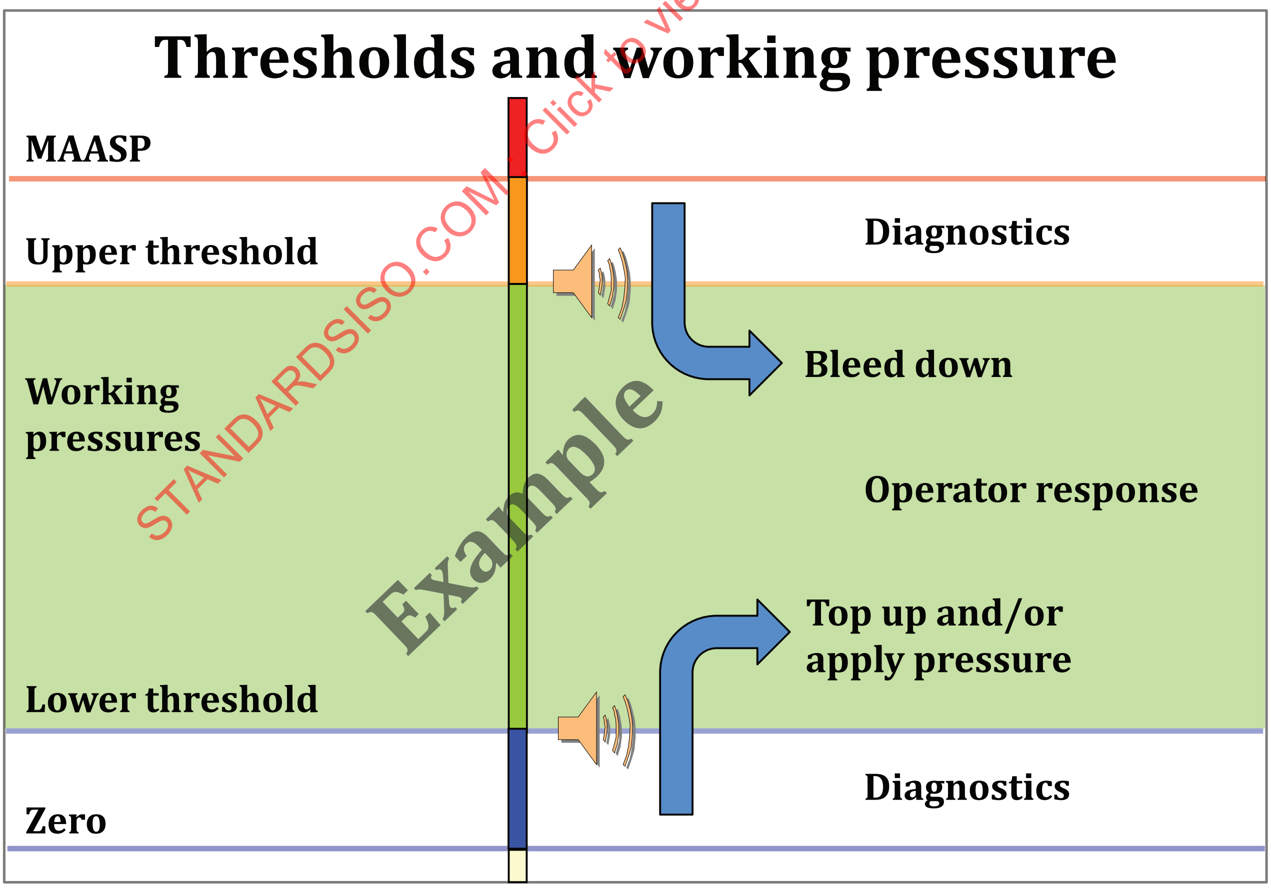


Figure 9 — Illustration of thresholds and MAASP

The operating range is applicable only to accessible annuli that allow for pressure management, such as bleed-down/build-up. Trapped annuli, without monitoring, should have been considered in the design of the well.

For active annuli, i.e. annuli that are being used for injection or gas-lift, the principles of inflow testing and monitoring of adjacent annuli should be followed. Annex O provides an example as to how inflow testing is used for leak testing gas-lift valves.

It is recommended not to operate an annulus at a pressure that is greater than the MAASP of the adjacent annulus. This prevents an excursion above the MAASP in the adjacent annulus, should a leak occur between the annuli.

9.5.7 Maintaining annulus pressure within the thresholds

When the annulus pressure reaches the upper threshold value, it should be bled off to a pressure within the operating range. Conversely, the annulus should be topped up when the lower threshold is reached.

The type and total volume of the fluid recovered or added, all annulus and tubing pressures and the time to bleed down should be documented for each bleed-down or top-up.

The frequency of bleed-downs and the total volume of fluids recovered from the bleed-downs should be monitored and recorded. These should be compared to limits established by the well operator and, when exceeded, an investigation should be undertaken.

In the event the annulus pressure exceeds the MAASP, this event should be investigated and risk-assessed.

9.5.8 Review and change of MAASP and thresholds

The well operator should define the process of annulus review (investigation) when the operating conditions indicate that the pressure is sustained or a leak in a well barrier has occurred.

When such a review is required, it may be based on established criteria for:

— frequency of annulus pressure bleed-downs or top-ups;

— abnormal pressure trends (indicating leaks to/from an annulus);

— volume of annulus bleed-downs or top-ups;

— type of fluid used or recovered (oil/gas/mud);

— pressure excursions above MAASP and/or upper threshold.

The review should focus around the following elements:

1) source of the sustained annulus pressure based on sample and fingerprint results compared to original mud-logging data;

2) source fluid composition and pore pressure;

3) flow path from the source to the annulus (or vice versa) under review;

4) leak rate, potential volumes and density changes in annulus;

5) condition of the well (remaining life);

6) content of the annulus and liquid levels;

7) inflow rate and/or annulus pressure build-up rate testing;

8) casing shoe strength changes.

The upper threshold, in the event of sustained casing pressure, should be risk-assessed against the pressure capacity of the outer adjacent annulus to ensure that it can contain the pressure, should a failure occur in the annulus which has the sustained pressure.

If gas is the original source of annulus pressure and the well operator has confirmed the originating source by:

— fingerprinting against original mud-logger data;

— assessing the risk of loss of containment (subsurface) based on shoe strength; and

— original-source pore pressure;

the well operator may consider recalculating the MAASP, taking into account the impact of the average fluid gradient estimated in the fluid column. Annex S provides an example about the change in MAASP calculation.

9.6 Well maintenance

9.6.1 General

In the context of well integrity management, the maintenance requirements are those concerned with the maintenance and preservation of the established well barriers and their elements. The well operator shall have a maintenance programme for those mechanical WBEs that require servicing. For some mechanical parts and components, it may be desirable to record and track serial numbers in order to maintain traceability of the materials, design specifications, and performance history of components. The maintenance requirements can change during the well life cycle.

Maintenance activities are the means by which the continued availability, reliability and condition of the well barriers, WBEs, valves, actuators and other control systems are periodically tested, functioned, serviced and repaired.

Maintenance is conducted to inspect, test and repair equipment to ensure that it functions as intended and it remains within the limits of its performance specification. A planned maintenance programme sets out which maintenance activities are performed at a predetermined frequency.

The well operator should address all the identified respective components in a planned maintenance programme. These components typically include, but are not limited to, the following:

— wellhead, tubing hanger and tree, including all valves, bonnets, flanges, (tie-down) bolts and clamps, grease nipples, test ports, control line exits;

— monitoring systems (including gauges, transducers, transmitters and detectors, corrosion probes and/or coupons);

— annulus fluids;

— downhole valves (SCSSV, SSCSV, ASV, gas-lift valves);

— ESD systems (detectors, ESD panels, fusible plugs);

— chemical injection systems.

There are two levels of maintenance, i.e. preventive and corrective:

a) preventive maintenance is carried out at a predefined frequency based on the working conditions, the well type, and the environment in which the well is operating, e.g. offshore, onshore, nature reserve or as directed by a regulator;

b) corrective maintenance is typically triggered by a preventive maintenance task that identifies a failure or by an ad hoc requirement that is identified by a failure during monitoring of a well.

The number of corrective maintenance tasks within a given period is a qualitative indication of the quality of the preventive tasks or of the monitoring frequency. The ratio of corrective maintenance tasks to preventive maintenance tasks can be measured against established acceptance criteria.

In cases where a well barrier cannot be maintained according to the original design specification, the well operator should perform a risk assessment to establish the controls required to mitigate the risk to an acceptable level.

During the well life cycle, well conditions or well usage can change. This should initiate a re-evaluation of the barrier(s) and the well operating limits through the MOC process.

WBEs and their functions and failure characteristics can be used in developing appropriate acceptance, monitoring and maintenance criteria. Examples are shown in the well integrity maintenance and monitoring model in Table 3.

Table 3 — Example of a well maintenance and monitoring matrix

Assurance task		Well type						
		Offshore well	**Subsea well**	**High pressure well onshore**	**Medium pressure well onshore**	**Low pressure well onshore**	**Hydrostatic well onshore**	**Observation well**
Maintenance	*Example of time based preventative maintenance frequency in months*							
	Flow wetted components maintenance and inspection frequency	6	6	12	12	12	24	48
	Non-Flow wetted components maintenance and inspection frequency	12	12	24	24	24	48	96
Monitoring	*Example of time based monitoring frequency in days*							
	Monitoring frequency active wells	1	1	1	7	7	14	30
	Monitoring frequency shut-in wells	7	7	14	30	30	60	90

When defining schedules and test frequencies, the well operator should take into account the following:

— original equipment manufacturer specifications;

— risk to environment and personnel exposure;

— applicable industry-recognized standards, practices and guidelines;

— well operator-relevant policies and procedures.

The well operator should have a documented programme for investigating leaks or faults, and a defined time to implement corrective action(s) based upon the risk.

9.6.2 Replacement parts

Replacement parts should be obtained from the original equipment manufacturer (OEM) if possible, or an OEM-approved manufacturer. Deviation from this practice should be clearly documented and justified, and its potential impact on the well operating limits should be evaluated.

9.6.3 Frequency of maintenance

The well operator shall define and document the schedules and frequencies for maintenance activities. A risk-based approach can be used to define the frequency, and an assessment matrix as shown in

Figure 7 can be used in the process that can be mapped as shown in the example in Table 3. Frequencies can also be established for identified well types, based on the well-type risk profiles.

The frequency may be adjusted if it is found that the ratio of preventive/corrective maintenance tasks is very high or very low, once sufficient historical data have been obtained that establish clearly observable trends.

9.6.4 Component testing methods

The types of tests that may be performed as part of the maintenance programme and in accordance with the performance standards as defined by the well operator are outlined in 5.9. Annex G provides an example of a well integrity performance standard.

9.7 Risk assessment of well integrity failure and its management

9.7.1 General

The well operator shall assess and manage risks associated with failure(s) of a well barrier or well barrier element(s). These risks can be assessed against the performance standards as defined by the well operator, by legislation or by industry standards.

9.7.2 Integrity failure ranking and prioritization

A well integrity failure should be risk-assessed against the criticality of the failed barrier element.

The priority-to-repair (response time) should be set in accordance with the risk exposure.

The well operator should have a risk-based response model and structure in place that provides guidance for adequate resources, such as spares, tools, contracts, etc., in order to meet the response time to effect repairs as defined in the model. The model can be based on the concept of ALARP (see Annex A), so that the response is commensurate with an acceptable level of risk and risk exposure while conducting the remedial action.

The well integrity response model should include, but should not be limited to:

— well-type risk profile;

— single barrier element failures;

— multiple barrier element failures;

— time-based course of action.

9.7.3 Well failure model

A well failure model approach may be adopted to streamline the risk assessment process, the plan of action and the response time to repair when failures occur. A well failure model is constructed as a matrix that identifies the most common modes of well failure seen by the well operator. Each mode of failure has an associated action plan and associated response period. By having agreed action plans and response times, the well operator is better able to manage equipment, spare parts, resources and contracts to meet the response times specified in the well failure model.

A well failure model is constructed in a step-by-step approach, as follows:

a) Identify typical modes of failure, both surface failures and subsurface failures. These failure modes can be documented in a list format or illustrated on a diagram.

b) Once the failure list is constructed, based on generic risk assessment, an action plan is agreed upon, including resources and responsibilities required for each identified failure mode. Escalation of response time to multiple failures should be given due consideration, since the combined result of two simultaneous failures can often be more severe than had the two failures occurred separately.

c) A risk-assessed time to respond to the failure is assigned to each action plan. Here it is detailed whether the well is allowed to operate, or is shut-in or suspended during these periods.

d) It is often useful to rank or categorize failures for the purpose of prioritization and reporting. This may be a “traffic light” approach (red, amber, green) or a ranking system (1 to 10 for example).

By adopting a well failure model, the well operator predefines the level of risk, the actions, response times and resources required for common modes of well failure. An example of response times is shown in Table 4.

If one or more unacceptable leak rates are found, the well operator should risk-assess the potential loss of containment and put mitigating measures in place as deemed necessary by the assessment. Operating outside a defined envelope should be managed by a formal risk-based deviation system.

Any well failures which occur that are not covered by the well failure model should be risk-assessed in the conventional manner.

Table 4 — Example of a well failure response times and corrective action matrix

Failed component(s)		Well type						
		Offshore well	Subsea well	High pressure well onshore	Medium pressure well onshore	Low pressure well onshore	Hydro-static well onshore	Obser-vation well
Time allowed to conduct corrective action / repair	*Example flow wetted component failure single response frequency in months*							
	Tree master valve	1	3	3	3	3	6	12
	Flowing valve	3	3	6	6	6	12	24
	Subsurface safety valve	1	3	3	3	3	NA	NA
	Production packer	6	6	12	12	12	NA	NA
	Gas-lift valve	3	3	6	6	6	12	24
	Tubing	6	6	12	12	12	24	48
	Example flow wetted component failures multi response frequency in months							
	Tree master valve + subsurface safety valve	0	0	1	2	3	NA	NA
	Tree flow wing valve + master valve	0	0	2	3	4	6	12
	Example non-flow wetted component failure single response frequency in months							
	Annulus side outlet valve	3	3	6	6	9	12	12
	Annulus to annulus leak	6	6	6	12	12	12	12
	Sustained casing pressure investigation	1	1	1	1	1	2	2
	Example non-flow wetted component failures multi response frequency in months							
	Sustained casing pressure + annulus valve	1	1	1	2	2	3	3
	Annulus leak + sustained casing pressure	1	1	1	2	2	6	6
	Example combined flow wetted and non-flow wetted component failures response frequency in months							
	Production tubing + casing leak	1	1	1	2	4	6	6
	Tree master valve + annulus valve	1	2	2	2	2	4	9
	Sustained intermediate annulus pressure + tubing leak	1	1	1	2	2	4	4

9.8 Reporting and documentation

The well operator should record and document well integrity activities in its WIMS undertaken during the operational phase of a well, and should define the period of time that these records should be kept available.

The information to be recorded should include, but is not limited to, the following:

- well barrier schematics;
- all well hand-over information;
- production/injection information;
- performance standards;
- annulus pressure monitoring;
- diagnostic tests performed;
- fluid analyses;
- preventive maintenance activities;
- corrective maintenance (repair and replacement) activities;
- traceability of equipment and replacement parts.

The well operator should define and track key performance indicators (KPI), which should be accessible to responsible and accountable personnel. Examples of KPIs can be found in Annex K.

9.9 Periodic well review

9.9.1 Well use review

The well operator should establish a periodic well review process for the further use of suspended or shut-in wells. The well operator should establish a plan that identifies restoration to production or injection, suspension or further suspension, or abandonment of the identified wells, which is in accordance with the WIMS in order to mitigate the risk of loss of containment. This process should document and detail the intended plan for the well, which may include its permanent abandonment.

Wells should not be left shut-in with no defined plans for re-use or abandonment. The well operator should establish a prioritised schedule for well abandonment activities. Prioritization can be driven by many factors, including:

- current and forecast well integrity status;
- regulator timing requirements;
- risk to regional environment;
- regional concurrent activities;
- campaign activity optimization;
- opportunity-based factors (e.g. rig availability).

A well should not remain a suspended well indefinitely.

9.9.2 End of well life review

The end of design life can differ from the actual end of life of a well. End of life can result from economic performance considerations, deteriorating well integrity issues such as loss of well barriers, or other factors as determined by the well operator. Any of these conditions that become evident should trigger a review that assesses the well status for safe continuation.

If the assessment demonstrates that the well is unsuitable for continued use, the well operator should either plan to rectify the well's condition, or plan for suspension or abandonment.

The period for which a well life can be extended is determined on a case-by-case basis.

9.10 Change of well use

If a well's use is to be changed, it should be managed through the MOC process and follow the requirements of the well integrity life cycle phases.

9.11 Well stock performance review

The well operator should conduct performance reviews to assess the application of the WIMS to a defined well stock. It is recommended that the well stock included within the scope of the review normally comprises a group of wells at a particular location, production facility or field but, where deemed appropriate, the well stock may be a smaller group of wells or even an individual well.

The primary objectives of a performance review are to:

— assess whether the well stock is performing in accordance with the WIMS and its objectives;

— assess how the well stock conforms to the WIMS processes and adheres to the policies, procedures and standards defined in the WIMS;

— identify areas of improvement.

Where areas for improvement are identified, any changes required to address these improvements should be specified and implemented. Implementation of any changes shall follow the risk assessment and MOC processes as described in 5.5 and 5.11, respectively.

Performance reviews should be carried out at a defined frequency determined by the well operator based upon associated risks.

In addition, ad hoc reviews should be performed as and when deemed necessary when new information becomes available that can have a significant impact on well integrity risk or assurance processes.

The review shall be performed by a group of personnel deemed competent in well integrity principles and who are familiar with the well operator's WIMS. It is recommended that, where practicable, at least some personnel involved in the review not be directly involved in well integrity management of the well stock under review, in order to provide a broader perspective and to aid in identifying any issues that can have been overlooked by those engaged in day-to-day operation of the wells under review.

In performing the review, the well operator should typically carry out the activities listed in Table 5.

Table 5 — Performance criteria and associated review activitie

Performance criteria	Performance review activity
Conformance	Check that policies, procedures and processes are up-to-date, approved for use and being consistently applied.
	Compare current documented well operating limit(s) against the current in-service condition/use of the wells. Check that the wells are currently operating within their defined operating limits, particularly if well condition/use has changed or original planned well design life has been exceeded.
	Examine changes to well operating limits since the last review and reasons for these changes. Check whether the well operating limit(s) are approaching a condition where they cannot support the continued use of the well (including any potential to exceed the original planned well design life).
	Examine actual monitoring, testing and maintenance frequencies against planned frequencies to check whether planned frequencies are being achieved or, where applicable, that a deviation from a planned frequency has been justified, documented and approved.
Documentation	Check that WIMS activities are clearly and adequately documented in accordance with any defined requirements, and that the documentation is readily available to relevant personnel.
Governance	Check that specified levels of authority for any approval processes are being correctly applied within the WIMS.
Measurement	Review well integrity key performance indicators. Identify any trends and areas of the WIMS that can require modification to address any deficiencies indicated by the trends.
	Check that any WIMS audit findings, if applicable, are being adequately addressed and, where necessary, identify areas where this is not the case.
	Check on type and quantity of reported non-conformances and incidents associated with well integrity and, where applicable, identify changes to the WIMS to avoid such issues in future.
Organizational capability	Check that relevant personnel clearly understand their involvement in well integrity management processes and that they are competent to fulfil the requirements specified in the WIMS.
	Check that adequate resources are assigned to address all the elements of the WIMS in accordance with defined requirements.
Relevance	Check that WIMS processes are up-to-date and applicable to the well stock being assessed.
	Examine basis for current documented operating limits, performance standards and monitoring, testing and maintenance processes. Assess whether any changes to the WIMS are required to capture — enhancements to current well operator policies and procedures and risk management principles and practices; — current legislative requirements; — any new internal or industry guidance, learnings, experience or best practices identified since the last review; — any supplier recommendations/notifications regarding equipment use or replacement/obsolescence since the last review; — availability, since the last review, of new or improved techniques or technologies that might enhance well integrity if applied to the well stock.

Table 5 *(continued)*

Performance criteria	Performance review activity
Risk and reliability	Check whether risk assessments are being performed in accordance with defined standards and procedures, all relevant risks have been identified, the magnitude of the risks are correctly defined and risk mitigation requirements have been implemented.
	Check that risks are being managed effectively in accordance with defined standards and procedures.
	Examine numbers and types of well anomalies encountered since the last review. Examine failure and corrective maintenance trends relative to planned monitoring, testing and maintenance frequencies. Check whether the current reliability and condition of the well stock is aligned to the current frequency of planned monitoring, testing and maintenance of the well components.
Timeliness	Check on timeliness of addressing well anomalies relative to defined requirements and, where applicable, identify any processes within the WIMS that can be modified to enhance timeliness while still meeting defined requirements.

9.12 Continuous improvement

In accordance with 5.12, the well operator should have an established continuous improvement process. For the operational phase, this improvement process should include learnings from operations, maintenance and verification tasks, which can then be used to provide feedback to the operational phase and other relevant life cycle phases, e.g. by identifying:

— non-conformances to well operating conditions within the well operating limits;

— increasing and unacceptable failure rates for various components;

— number of corrective maintenance tasks *vs.* preventive maintenance tasks;

— frequency of exceeding maintenance and verification frequencies;

— deviations from well surveillance plans (e.g. planned corrosion surveys);

— deviations from annulus pressure management procedures.

10 Well intervention phase

10.1 Well intervention phase objectives

There may be occasions when the operational phase of a well is interrupted to carry out well intervention activities. For the purposes of this document, a well intervention includes any activity where the well operator breaks containment to enter the well. The elements of this phase are detailed in Figure 10.

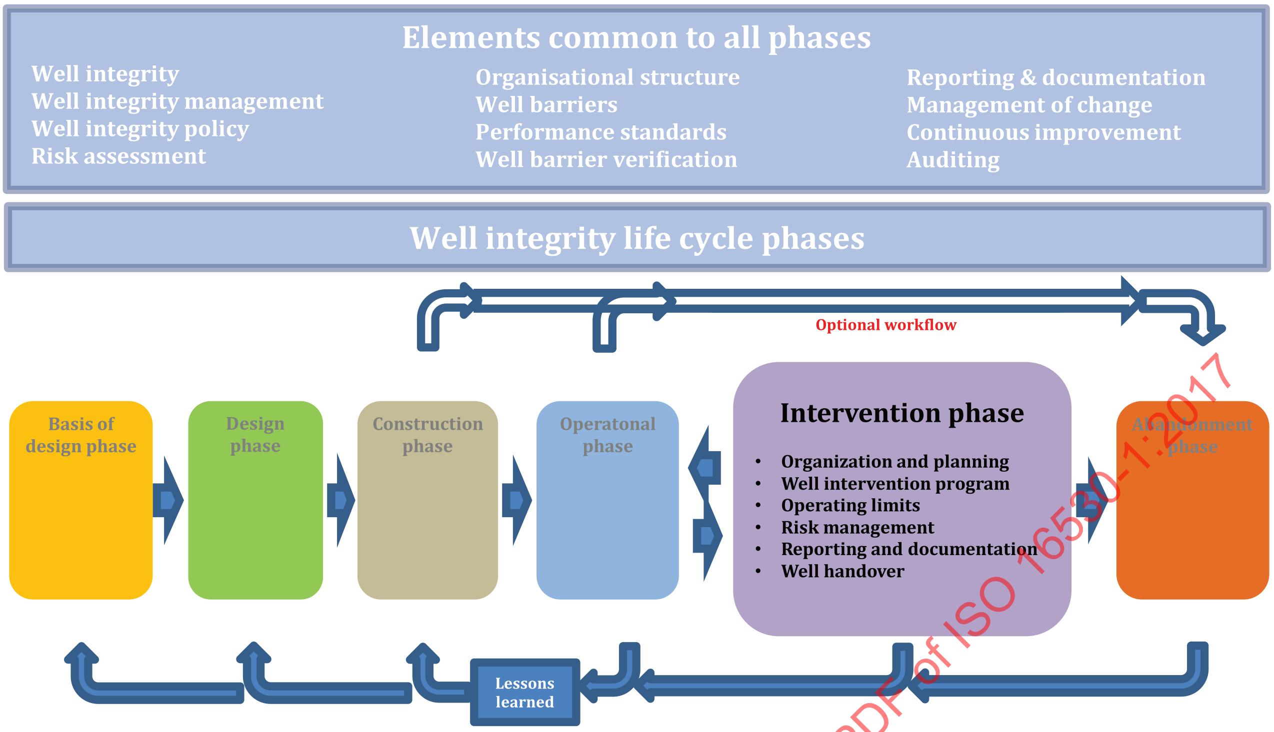


Figure 10 — Well intervention phase

The well intervention phase defines the minimum requirements for assessing well barriers prior to, and after a well intervention, which requires entering into the established well barrier containment system.

Well intervention can be required in order to carry out the following:

— production performance monitoring or enhancement;

— reservoir surveillance;

— well integrity diagnostic work;

— repair or replacement of downhole components;

— repair or replacement of wellhead and tree components;

— changing production or injection zones;

— plug back and side track operations;

— well suspension;

— final well abandonment (see Clause 11).

Where the intervention activity includes the replacement or reconstruction of well components, the requirements of Clause 7 for design and Clause 8 for construction may apply.

10.2 Organizational structure and tasks

The well operator should establish and maintain strategic plans that include organizational capability to effectively plan and execute well intervention activities. This includes provision for scheduled routine well intervention activities and the capacity to react to unscheduled events impacting on well integrity.

The well operator should define the roles, responsibilities, and authority levels required and assigned to those involved in the planning and execution of well intervention activities. RACI charts can be a useful way to summarize the organizational structure required for these activities.

Typical examples of functional skills that are needed include:

— drilling and completion engineering and operation;

— subsurface geology and reservoir engineering;

— specialists in wireline, coiled tubing and snubbing services;

— logging and interpretation (e.g. calliper log, MFL log);

— cement evaluation;

— specialists in well services and SIMOPS;

— risk assessment and management.

The well operator should define the well intervention competence requirements and qualifications of personnel utilized to accomplish the requirements of the well intervention phase. These tasks are similar to those found in Clause 8.

NOTE See ISO/TS 17969.

10.3 Well handover

As presented in 5.10.4, depending on the organizational structure of the well operator, there can be a requirement to ‘hand over’ the ownership/custodianship of the well when moving from one well life cycle phase to another. In the case of well intervention activities this may be, for example, a handover from a production operations group to a well intervention/workover team, and back again to production operations.

The well operator should establish and maintain well handover procedures to manage this process. Such procedures should address the following:

— when a well handover occurs;

— check list of items to be documented before handover can occur (see Annex J);

— well records and reports to be available and generated at handover;

— transfer of roles and responsibilities at handover.

10.4 Well intervention programme

All well intervention activities should be conducted in accordance with an approved programme. The well intervention programme should address the well intervention requirements, as well as the mitigation and control measures required for the hazards and risks associated with well integrity. The well intervention programme should contain well barrier plans and schematics, as well as barrier verification methods prior to and after the well intervention.

10.5 Well barriers

10.5.1 General

Prior to intervention in a well, an assessment shall be made of the current well barrier status. The assessment should identify any uncertainties in the well barrier integrity. If the integrity of a barrier cannot be confirmed, the well operator should risk-assess the current status and determine any further actions.

The assessment should also address the potential for well barrier failures during planned activities, and the contingencies required should a well barrier fail.

10.5.2 Well barrier plans

Well barrier plans/schematics should be prepared for each change in barrier configuration before and after the well intervention, in accordance with the barrier philosophy (see 5.7.2).

This well barrier plan should identify potential leak paths, and the barriers required to be in place and verified to isolate such leak paths. Any deviation should be followed by MOC procedures.

10.5.3 Well barrier qualification

If a WBE needs to be repaired or replaced during a well intervention, the equipment and material selected should be qualified in a manner to demonstrate fitness for purpose.

The well operator should make use of existing industry standards and approved vendor procedures covering the manufacture, inspection and quality control of components that make up the well barriers.

10.5.4 Well barrier verification

Prior to the start of any well intervention activity, the well operator should establish the barrier verification procedures to be applied in order to confirm the integrity of required well barriers. Such verification procedures may be applied:

a) immediately prior to the well intervention, for existing well barriers;

b) during the well intervention activity, when barrier configuration or status is changed;

c) at the end of the well intervention programme, as required to demonstrate the acceptable well integrity status prior to handover and reinstatement of the well to operational phase.

In the event a well barrier fails to meet the verification criteria, the well operator should have contingency plans in place to maintain (or re-instate) acceptable well integrity.

For activities restoring or changing well barriers, the requirements and processes of Clause 8 should be followed.

10.5.5 Well operating limits

Following well intervention activity, the well operator should review and, if required, update the well operating limits in accordance with 5.8.2 and 5.11.

Due consideration should be given to the following:

— changes in downhole hardware;

— degradation of well components;

— changes to wellbore fluid composition;

— changes in the capacity to monitor well parameters;

— results of barrier verification activities.

10.6 Risk management

The well operator should identify the key risk areas for each well intervention activity, and identify the preventive controls and mitigation measures that are required to manage the well integrity aspects of the activity. The risks should be documented in a risk register for the activity and be reviewed with personnel involved with performing the intervention.

10.7 Management of change

If integrity conditions are encountered during intervention which are significantly different than expected, the intervention plan shall be re-verified and/or revised to address the different conditions through the required MOC process (see 5.11).

Any changes as a result of these reviews should be properly documented and included in the well barrier schematic, if appropriate.

After intervention, the risk register should be updated to reflect any change in the level of risk based on new information.

10.8 Deliverables (documentation and reports)

The well operator should identify all information that is required to be recorded for on going well integrity management after the well intervention activity. This may include, but is not limited to, information on the following:

a) well handover (see 10.3 and Annex J);

b) lessons learned (see 5.12.3).

Additionally, this may include updates to:

— controlled 'as-constructed' well records;

— well operating limits (see 5.8.2);

— well inspection and maintenance requirements;

— risk register.

11 Well abandonment phase

11.1 Well abandonment phase objectives

The well abandonment phase defines the requirements and objectives to permanently abandon a well. The elements of this phase are detailed in Figure 11.

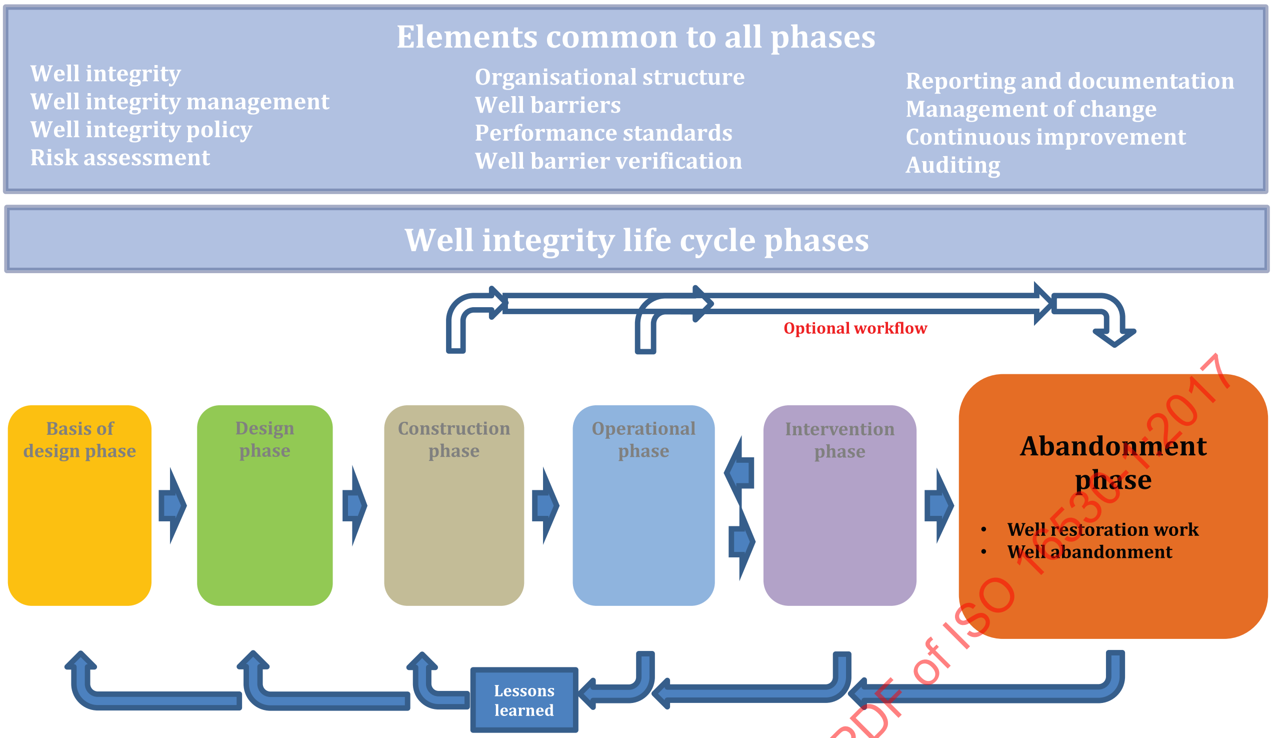


Figure 11 — Well abandonment phase

Well abandonment is the final activity performed on the well, and includes the establishment of permanent barriers in the wellbore, such that integrity is retained with no intention of future well re-entry. There can be additional local regulations that require additional tasks to be performed when abandoning a well, such as wellhead removal, and the well operator should encompass these in their plans.

Although some well operators, and some regulatory bodies, can require the periodic inspection of abandoned wells, the integrity of the final well abandonment configuration is not dependent on such periodic inspections.

Well abandonment requirements should be considered throughout the life cycle of the well, starting from the basis of design. Wells should be designed, constructed and maintained such that they can be effectively abandoned. The well operator's barrier philosophy should address the requirements of well abandonment (see 5.7.2).

In preparing for well abandonment activities, the well operator should identify the objectives of the activity and options for achieving such objectives. The objectives of well integrity-specific activities for well abandonment may include, but are not limited to:

— prevention of formation, injection and wellbore fluids escaping to the environment;

— prevention of cross-flow of fluids between discrete formations/zones;

— prevention of contamination of aquifers;

— isolation of radioactive materials or other hazardous material that can remain in the wellbore at the time of abandonment;

— specific legal requirements.

11.2 Organizational structure and tasks

The well operator should establish and maintain strategic plans for the timely final abandonment of their entire well stock. This may include long-term planning for end-of-life decommissioning activities.

The well operator should establish and maintain an organizational capability to effectively execute the well abandonment plans, as appropriate for its wells. The organizational structure required to support well abandonment planning and execution may include access to expertise. Typical examples of functional skills that are needed include:

— drilling, completion and interventions engineering and operations;

— cementing engineering and operations;

— subsurface geological and reservoir engineering;

— structural engineering;

— risk assessment and management.

The well operator should clearly define the roles, responsibilities and authority levels required and assigned to those involved in well abandonment planning, execution, and any post-abandonment activities. RACI charts can be a useful way to summarize the organizational structure required for these activities.

The well operator should define the competence requirements, and ensure only competent people are assigned to well abandonment planning and execution activities.

NOTE See ISO/TS 17969.

11.3 Well abandonment programme

All well abandonment activities should be conducted in accordance with an approved programme created for this phase. The well abandonment programme should address the well abandonment requirements, as well as the mitigation and control measures required for the hazards and risks associated with well integrity. The abandonment programme should contain well barrier plans and schematics, as well as barrier verification methods prior to and during the well abandonment.

Requirements from the well design phase may be pertinent to the well abandonment phase, and should be incorporated into the abandonment programme as applicable.

11.4 Well barriers for abandonment

11.4.1 General

In the selection of barriers and the quantity of barriers for well abandonment, the following factors should at least be considered:

— identification of potential sources of flow that can exist at the time of well abandonment;

— potential future flow sources due to reservoir re-pressurization;

— depletion of a reservoir leading to potential for cross-flow to other distinct zones;

— identification of potential leak paths;

— options to establish permanent barriers to potential leak paths at abandonment;

— capability to verify annulus cement isolation effectiveness (initially and prior to abandonment);

— capability to access well sections for placement of permanent barriers;

— formation compaction;

— seismic and tectonic forces;

— temperature;

— chemical and biological regimes that can exist.

11.4.2 Well barrier material selection and qualification

The materials selected for permanent barriers used for well abandonment shall be qualified to demonstrate they will retain integrity in the downhole environment to which they are reasonably expected to be exposed.

NOTE For example, see Oil and Gas UK, Guidelines on Qualification of Materials for the Abandonment of Wells.[25]

11.4.3 Well barrier placement, configuration and redundancy

The well operator shall specify the requirements for barrier position, placement, configuration and redundancy for specific isolation objectives, which may include isolation of the following:

— reservoir hydrocarbon zones;

— shallow gas zones;

— tar and coal zones (non-flowing hydrocarbons);

— over-pressured water zones;

— injection fluids (e.g. water, CO_2, cuttings re-injection);

— shallow aquifers;

— hazardous materials left in the wellbore.

NOTE For example, see NORSOK D-010[21] or Oil and Gas UK, *Guidelines for the Abandonment of Wells*[24].

11.4.4 Well barrier verification

The well operator should establish verification criteria, including applicable regulatory requirements, to confirm that the well barrier is in place and that it has the integrity to meet the objectives for which it was designed.

The abandonment barriers should be designed and deployed in such a manner that they can be verified during abandonment. Previously installed well barrier abandonment elements can degrade over time and may need to be re-verified based upon a risk assessment.

A process should be in place to confirm barrier verification requirements have been met during well abandonment.

11.4.5 Reference documents for well abandonment barriers

In the preparation of well abandonment programmes, the well operator shall verify the requirements of the currently applicable regulations.

The well operator should also review, and may choose to adopt in part or in full, current industry recommended practices. These may include, but are not limited to:

— Oil and Gas UK, *Guidelines for the qualification of materials for the abandonment of wells*;

— Oil and Gas UK, *Guidelines for the Abandonment of Wells*;

— NORSOK D-010;

— API/TR 10TR1.

11.5 Risk management

The well operator should identify the key risk areas for well abandonment activities, and the preventive controls and mitigation measures that are required to manage the well integrity aspects of the activity. The risks should be documented in a risk register (see 5.5.2) and be reviewed with personnel involved with performing the abandonment.

In planning for well abandonment activities, the well operator should clearly identify the following:

a) all the integrity objectives of the well abandonment activity;

b) the risks that can threaten achievement of each of the objectives;

c) the means available to control and mitigate such risks;

d) ability to comply with regulatory requirements.

In identifying and assessing such abandonment risks and objectives, the well operator should at least consider:

— the risks associated with any concurrent activities at the time of well abandonment;

— longer-term well ownership and liability, obligations and risk;

— potential future activities at the abandonment location or adjacent areas (surface and subsurface activities);

— potential changes in reservoir pressure and fluid composition due to future projects or natural processes.

11.6 Management of change

The MOC process described in 5.11 shall be applied during well abandonment planning and execution of activities, in order to address any changes to the well abandonment programme.

11.7 Deliverables (documentation and reports)

The well operator should identify documentation and reports which are required in order to;

a) result in final acceptance of the well abandonment and handover of the well location;

b) document the final well configuration at abandonment.

Information required to document the final 'as-constructed' well configuration at abandonment may include the following:

— final surveyed well surface location;

— definitive subsurface wellbore survey;

— details of all casing strings and completion components remaining in the well;

— cement tops, cement properties, type of support;

— cement plug foundation or support, e.g. bridge plug;

— barrier element location and composition;

— well barrier schematic;

— fluids remaining in the wellbore (type, properties);

— hazardous material left in the well (radioactive sources, chemicals, etc.);

— verification records of all permanent barriers;

— discussion on any concerns in achieving final abandonment objectives;

— final site inspection and condition report;

— continuous improvement review and feedback;

— recommendations for any post-abandonment activities;

— updated risk register.

The well operator should establish the requirements for long-term availability of well documentation after abandonment, and make provision for such requirements that address, but are not limited to:

1) period of time that records are to be kept;

2) accessibility of the well records;

3) secure record storage mediums and locations.

Annex A
(informative)

Risk assessment techniques

A.1 General

Risk assessment techniques are used to assess the magnitude of well integrity risks, and whether they are potential risks, based on an assessment of possible failure modes, or actual risks, based on an assessment of an anomaly that has been identified. When determining an acceptable level of risk, a methodology called “as low as reasonably practicable” (ALARP) is often applied. Applying the term ALARP means that risk-reducing measures have been implemented until the cost (including time, capital costs or other resources/assets) of further risk reduction is disproportional to the potential risk-reducing effect achieved by implementing any additional measure (see ISO 17776).

A risk assessment process typically involves:

— identification of the types of anomalies and failure-related events that are possible for the well(s) that are being assessed;

— determination of the potential consequences of each type of well failure-related event; the consequences can affect health, safety, the environment, cause business interruption, societal disruption or a combination of these;

— determination of the likelihood of occurrence of the event;

— determination of the magnitude of the risk of each type of well failure-related event based, on the combined effect of consequence and likelihood.

A.2 Types of risk assessment

A.2.1 Qualitative risk assessment can be used where the determination of both consequences and likelihood of event occurrence is largely based on the judgement of qualified and competent personnel, based on their experience.

A.2.2 Quantitative risk assessment (QRA) is another technique that can be applied to assess well integrity risks. This technique also assesses both consequences and probability, but uses information from databases on well integrity failures to quantify the probability of a given event occurring.

A.2.3 Failure-mode and effects and criticality analysis (FMECA) can also be used to determine well integrity risks. FMECA is particularly useful in establishing the types of component failure that can occur, the effect on the well barrier and the likelihood of such failures occurring. This information can then be used to assist design improvements and to establish the type and frequency of monitoring, surveillance and maintenance required to reduce the risk of the failures modes identified as part of the FMECA. Detailed risk assessment methods and techniques can be found in ISO 17776, ISO 31000 and IEC 31010.

A.3 Risk control assessment

The bow-tie schematic is a useful methodology for identifying and documenting hazards, consequences, barriers (number required, prevention and recovery measures), and escalation factors and controls. Identified hazards are mitigated to an acceptable level through imposing barriers. An example of use of the bow-tie method is illustrated in Figure A.1. Table A.1 shows the applicability of risk assessment tools to the various elements of the risk assessment process.

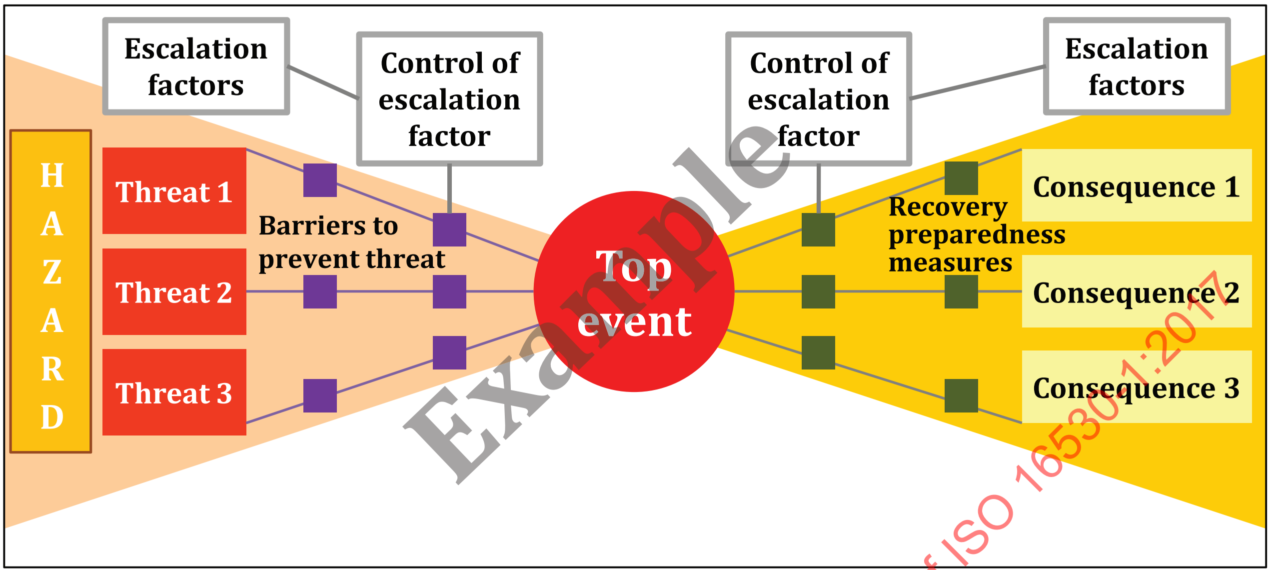


Figure A.1 — General example of a bow-tie schematic

Table A.1 — Applicability of tools used for risk assessment (see IEC 31010:2009, Table A.1)

Tools and techniques	Risk assessment process [a]				
	Risk identification	Risk analysis			Risk evaluation
		Consequence	Probability	Level of risk	
Brainstorming	SA	NA	NA	NA	NA
Structured or semi-structured interviews	SA	NA	NA	NA	NA
Delphi	SA	NA	NA	NA	NA
Check-lists	SA	NA	NA	NA	NA
Primary hazard analysis	SA	NA	NA	NA	NA
Hazard and operability studies (HAZOP)	SA	SA	A	A	A
Hazard Analysis and Critical Control Point (HACCP)	SA	SA	NA	NA	NA
Environmental risk assessment	SA	SA	SA	SA	SA
Structured What If Technique (SWIFT)	SA	SA	SA	SA	SA
Scenario analysis	SA	SA	A	A	A
Business impact analysis	NA	SA	SA	SA	SA
Root cause analysis	NA	SA	SA	SA	SA
Failure mode effect analysis	SA	SA	SA	SA	SA
Fault tree analysis	A	NA	SA	A	A
Event tree analysis	A	SA	A	A	NA
Cause and consequence analysis	A	SA	SA	A	A
Cause-and-effect analysis	SA	SA	NA	NA	NA
Layer of protection analysis (LOPA)	A	SA	A	A	NA

Table A.1 *(continued)*

Tools and techniques	Risk assessment process [a]				
	Risk identification	Risk analysis			Risk evaluation
		Consequence	Probability	Level of risk	
Decision tree	NA	SA	SA	A	A
Human reliability analysis	SA	SA	SA	SA	A
Bow-tie analysis	NA	A	SA	SA	A
Reliability-centred maintenance	SA	SA	SA	SA	SA
Sneak circuit analysis	A	NA	NA	NA	NA
Markov analysis	A	SA	NA	NA	NA
Monte Carlo simulation	NA	NA	NA	NA	SA
Bayesian statistics and Bayes Nets	NA	SA	NA	NA	SA
FN curves	A	SA	SA	A	SA
Risk indices	A	SA	SA	A	SA
Consequence/probability matrix	SA	SA	SA	SA	A
Cost/benefit analysis	A	SA	A	A	A
Multi-criteria decision analysis (MCDA)	A	SA	A	SA	A

[a] SA = strongly applicable, NA = not applicable, and A = applicable

Annex B
(informative)

Risk register

Table B.1 gives an example of a risk register to document risks to well integrity (see 5.5.2). Table B.2 gives an explanation of the column headings used in Table B.1.

Table B.1 — Example of risk register

ID	Hazards	Risk description		Existing safeguards	Risk before mitigation		Risk mitigating control				Risk after mitigating control		Risk status	Comments
		Causes	Consequences		Likelihood	Consequence	Measure	Status	Responsible	Due date	Likelihood	Consequence		
1	Tubing to annulus leak	Corrosion due injection water quality out of spec	Loss of primary well barrier	Continous monitoring of injection water quality	Seldom	Major	Re-evaluate material specification to increase operational limits for injection water quality	Proposed	Well engineer	dd.mm.yyyy	Rare	Major	Open	
2														
3														

Table B.2 — Risk register header explanation

Item in Table B.1	Explanation
ID	Each risk element should have a unique identification number for use as reference.
Hazard	An event, condition or state involving increased risk of negative impact(s). The description should be short and to the point. Examples of hazards: casing leak, erosion, etc.
Risk description: Cause	A description of the cause(s)/trigger(s) that can lead to the occurrence of the hazard.
Risk description: Consequence	A description of the consequence(s) if the hazard occurs. The consequence refers to the possible effects of the hazard if it occurs.
Existing safeguards	Existing safeguards relate to measures or barriers (technical or organizational) that are already planned or in place to prevent the hazard from occurring.
Risk before mitigation: Likelihood	The likelihood of the consequence occurring, taking into account the existing safeguards. The probability is selected from predefined categories in the risk assessment matrix.
Risk before mitigation: Consequence	An expression for the consequence of the hazard taking into account the existing safeguards. The impact is selected from predefined categories in a risk assessment matrix.
Risk-mitigating control: Measures	Probability- or consequence-reducing measures to mitigate the risk. For each risk, consider any risk-reducing controls that have the potential to reduce risk to within the effect of the existing safeguards. Each measure should be evaluated in accordance with the ALARP principle.
Risk-mitigating control: Status	The status of the control measure. The status of implementation of a control measure should be described.
Risk-mitigating control: Responsible	Assign each control measure to a responsible person.
Risk-mitigating control: Due date	Assign a due date for each control measure. This date is the deadline for implementing the measure.
Risk after mitigating control: Likelihood	The Likelihood of the consequence occurring, taking into account the existing safeguards and the effects of planned control measures. The probability is selected from the predefined categories in the risk assessment matrix.
Risk after mitigating control: Consequence	An expression for the consequence of the hazard, taking into account the existing safeguards and the effects of any planned control measures. The impact is selected from predefined categories in a risk assessment matrix.
Risk status	The status of managing the risk should be described. Whenever a risk is closed or otherwise no longer relevant, it is recommended to change its status to closed. This will help in managing the risks.
Comments	Any information that can be relevant to document or communicate may be added in the comments text field.

Annex C
(informative)

Example of well integrity roles and responsibilities chart

Table C.1 provides an example of a RACI chart.

Table C.1 — Example of a roles-and-responsibility overview

No.	Activity	Well engineering	Production operations	Subsurface engineering	Well integrity engineering
1	Well charter/field development plan	C	—	AR	I
2	Well basis of design	C	—	AR	I
3	Well detailed design	AR	—	C	I
4	Construct well	AR	—	C	I
5	Calculate and set maximum allowable annulus surface pressures (MAASPs)	R	—	AR	I
6	Prepare handover documents	AR	I	C	—
7	Complete and validate well status	AR	I	C	—
8	Confirm as-constructed specification	C	C	AR	I
9	Sign off handover document	R	A	C	I
10	Define operating envelope; calculate high-pressure alarm (HPA) and triggers	I	C	AR	C
11	Monitor well and annuli	—	AR	C	—
12	Manage annulus pressure	—	AR	C	—
13	Carry out well maintenance (preventive and corrective)	R	AR	C	C
14	Conduct anomaly investigation	C	R	A	C
15	Carry out MAASP/trigger re-calculation	R	C	A	C
16	Conduct well integrity review	C	C	AR	C
17	Monitor compliance with WIMS requirements	—	C	C	A
18	Review, maintain and update process	I	I	I	AR
19	Well abandonment	R	A	C	C
R – Responsible, A – Accountable, C – Consulted, I – Informed					

Annex D
(informative)

Example of a well integrity competence matrix

Table D.1 provides an example of a well integrity competence matrix.

Table D.1 — Example of a well integrity competence matrix

No.	Activity	Well site operator	Well engineer and well intervention engineer	Petroleum engineer	Well integrity engineer
1	Well design and load case analysis	Awareness	Skill	Knowledge	Knowledge
2	Cementing and hydraulic ECD modelling	Awareness	Skill	Knowledge	Awareness
3	Assessment and well material selection	Awareness	Skill	Knowledge	Awareness
4	Well barrier assessment as-constructed	Awareness	Skill	Skill	Skill
5	Calculate and set MAASPs	Awareness	Skill	Skill	Skill
6	Monitor well pressures within envelope	Skill	Skill	Knowledge	Skill
7	Operate wellhead and Tree valves	Skill	Skill	Knowledge	Skill
8	Operate and equalize subsurface safety valves	Skill	Skill	Knowledge	Knowledge
9	Test wellhead and Tree valves	Skill	Skill	Knowledge	Knowledge
10	Test subsurface and surface safety valves	Skill	Skill	Knowledge	Skill
11	Monitor annulus pressures	Skill	Skill	Knowledge	Skill
12	Bleed down and top up annulus pressures	Skill	Skill	Knowledge	Skill
13	Assess well operating envelope	Knowledge	Skill	Skill	Skill
14	Maintain and grease wellhead and Tree valves	Knowledge	Skill	Knowledge	Knowledge
15	Repair/replace wellhead and Tree valves	Awareness	Skill	Knowledge	Knowledge
16	Repair and replace subsurface safety valves	Awareness	Skill	Knowledge	Knowledge
17	Install and remove wellhead plugs (BPV)	Awareness	Skill	Knowledge	Knowledge
18	Install and remove wellhead VR plugs	Awareness	Skill	Knowledge	Knowledge
19	Back-seat valves and repair stem seals	Awareness	Skill	Knowledge	Knowledge
20	Un-sting and bleed valve pressure	Awareness	Skill	Knowledge	Knowledge
21	Test wellhead hanger seal	Awareness	Skill	Knowledge	Knowledge
22	Re-energize wellhead hanger neck seal	Awareness	Skill	Knowledge	Knowledge
23	Pressure test annulus	Awareness	Skill	Knowledge	Skill
24	Pressure test tubing	Awareness	Skill	Knowledge	Skill
25	Install downhole isolation plugs	Awareness	Skill	Knowledge	Skill
26	Recalculate MAASP	Awareness	Knowledge	Skill	Skill
27	Annulus investigation	Awareness	Knowledge	Knowledge	Skill
28	Review further use (life cycle extension)	Awareness	Knowledge	Knowledge	Skill
29	Replace Tree	Awareness	Skill	Knowledge	Knowledge
30	Run corrosion logs	Awareness	Skill	Skill	Knowledge
31	Assess corrosion logs	Awareness	Knowledge	Skill	Skill

No.	Activity	Well site operator	Well engineer and well intervention engineer	Petroleum engineer	Well integrity engineer
32	Kill well	Awareness	Skill	Skill	Knowledge
33	Assess well barrier schematic	Knowledge	Skill	Skill	Skill
34	Risk-assess and process deviations	Knowledge	Knowledge	Knowledge	Skill

Annex E
(informative)

Examples of well barrier elements, functions and failure characteristics

Table E.1 lists the types of well barrier elements (WBEs), with a description of their functions and typical failure characteristics, that are relevant during the operational phase.

Other WBEs that are not listed in Table E.1 can be employed in wells and in these cases a similar documented evaluation should be made.

Table E.1 — Example of WBEs, their functions and failure modes

Barrier element type	Function	Failure characteristic (Examples)
Fluid column	Exerts a hydrostatic pressure in the wellbore that prevents well influx/inflow of formation fluid	Leak-off into a formation Flow of formation fluids
Formation	Provides a mechanical seal in an annulus where the formation is not isolated by cement or tubulars Provides a continuous, permanent and impermeable hydraulic seal above the reservoir Impermeable formation located above the reservoir, sealing either to cement/annulus isolation material or directly to casing/liner	Leak through the formation Not sufficient formation strength to withstand annulus pressure Not sufficient formation strength to perform hydraulic seal
Casing	Contains fluids within the wellbore such that they do not leak out into other concentric annuli or into exposed formations	Manufacturing flaw Leak at connections Leak caused by corrosion and/or erosion Wear Parted connections
Wellhead	Provides mechanical support for the suspending casing and tubing strings Provides mechanical interface for connection of a riser, BOP or production tree Prevents flow from the wellbore and annuli to other annuli or the environment	Leaking seals or valves Mechanical overload
Deep-set tubing plug	Provides a mechanical seal in the tubing to prevent flow in the tubing	Leaks across the seals, internal or external
Production packer	Provides a mechanical seal between the completion tubing and the casing/liner, establishing the A-annulus above and thus preventing communication from the formation into the A-annulus	Leak across the external packing elements Leak across the internal seals
Surface-controlled sub-surface safety valve (SCSSV)	Safety valve device installed in the production tubing string that is held open, usually by the application of hydraulic pressure in a control line. If there is loss of control-line hydraulic pressure, the device is designed to close automatically	Lack of control line communication and functional control Leaking above acceptance criteria Failure to close on demand Failure to close within the acceptable closing time

Table E.1 *(continued)*

Barrier element type	Function	Failure characteristic (Examples)
Liner top packer	Provides a hydraulic seal in the annulus between the casing and the liner, to prevent flow of fluids and resist pressures from above or below	Inability to maintain a pressure seal
Subsea tree	System of valves and flow conduits attached to the well-head at the sea floor, which provides a method for controlling flow out of the well and into the production system Additionally, it may provide flow paths to other well annuli	Leaks to the environment Leaks above the acceptance criteria Inability of valves to function Failure to close within the acceptable closing time Mechanical damage
Annulus surface-controlled subsurface safety valve	Safety valve device installed in the annulus that prevents flow of fluids from the annulus to the annulus wing valve	Lack of control-line communication and functional control Leaking above acceptance criteria Failure to close on demand Failure to close within the acceptable closing time
Tubing hanger	Supports the weight of the tubing and prevents flow from the tubing to the annulus or vice versa	Leak past tubing seal Mechanical failure
Tubing hanger plug	Mechanical plug that can be installed within the tubing hanger to allow for isolation of the tubing Often used to facilitate the installation of BOPs or tree repairs	Failure to hold pressure, either internally or externally
Wellhead/annulus access valve	Provides ability to monitor pressure and flow to/from an annulus	Inability to maintain a pressure seal, or leaking above acceptance criteria Unable to close
Casing/liner cement	Cement provides a continuous, permanent and hydraulic seal along well bore between formations and a casing/liner or between casing strings Additionally, the cement mechanically supports the casing/liner and prevents corrosive formation fluids coming into contact with the casing/liner	Incomplete fill of the annulus being cemented, longitudinally and/or radially Poor bond to the casing/liner or formations Inadequate mechanical strength Allows flow from/to formations behind the casing/liner
Cement plug	A continuous column of cement within an open hole or inside casing/liner/tubing to provide a mechanical seal	Poor placement, leading to contamination with other fluids in the well Insufficient mechanical strength Poor bond to the casing or formation
Completion tubing	Provides a conduit for fluid to/from the reservoir to/from surface	Leak to or from the annulus Wall thinning from corrosion and/or erosion not resistant to the load cases
Mechanical tubing plug	A mechanical device installed in completion tubing to prevent the flow of fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars	Inability to maintain a pressure seal

Table E.1 *(continued)*

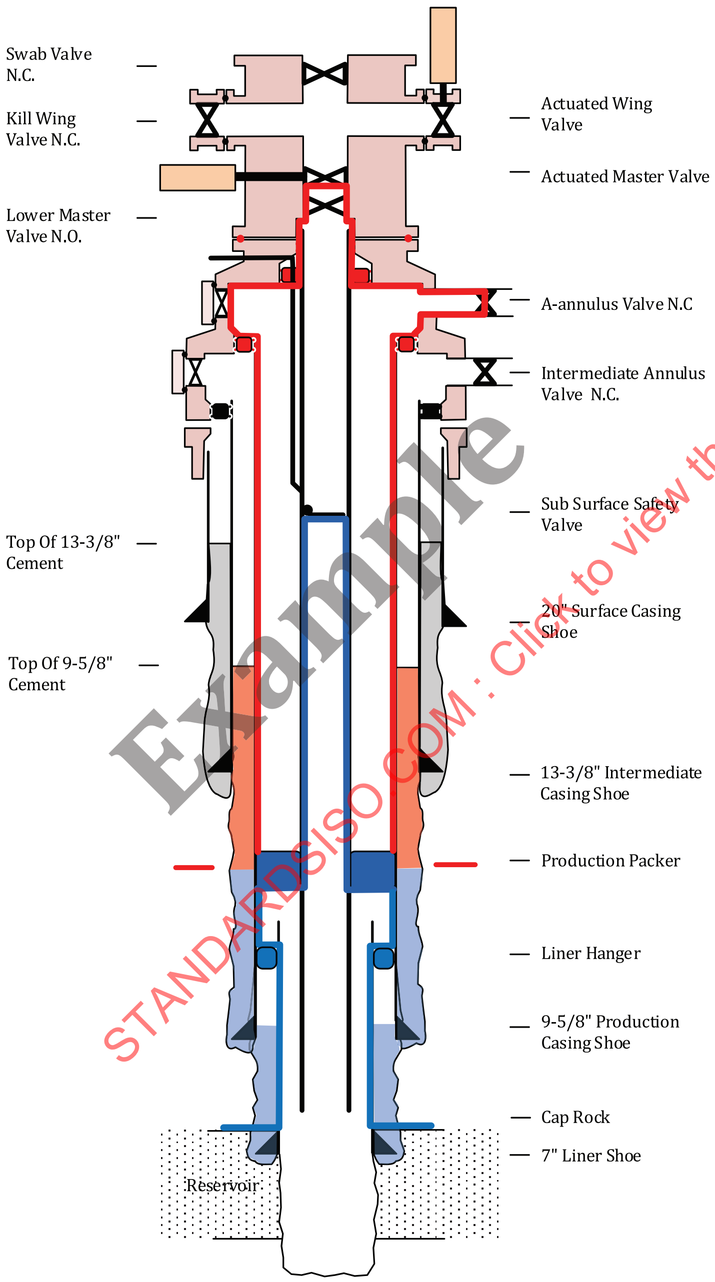
Barrier element type	Function	Failure characteristic (Examples)
Completion string component	Provides support to the functionality of the completion, i.e. gas-lift or side-pocket mandrels with valves or dummies, nipple profiles, gauge carriers, control-line filter subs, chemical injection mandrels, etc.	Inability to maintain differential pressure Valves leaking above the acceptance criteria
Surface safety valve(s) or emergency shut-down (ESD) valves	Provides shutdown functionality and isolation of well to production process/flow lines based on operating limits of the production system	Leaks to environment Leaks across valves above acceptance criteria Mechanical damage Failure to close within the acceptable closing time Inability to respond to process shutdown requirement over pressuring process
Surface tree	A system of valves and flow conduits attached to the wellhead that provides a method for controlling the flow out of the well and into the production system	Leaks to the environment Leaks across valves above the acceptance criteria Inability to function valves Failure to close within the acceptable closing time Mechanical damage

Annex F
(informative)

Examples of well barriers during the well life cycle and a well barrier schematic

ABC Oil and Gas Operator

XYZ Field	Well: *AA-01*	Prepared by:	Date	Primary Well Barrier to the Reservoir
Welltype: *Oil Producer*		Approved by:	Date	Secondary Well Barrier to the Reservoir
Date Original Well Completed:		Tree is rated to:		
Date Workover 1 Completed:		Wellhead is rated to:		N.O. = Normally Open N.C. = Normally Closed
Date Workover 2 Completed:		Tubing is rated to:		A-annulus MAASP:
Drawing Ref:		Drawing Rev:		B-annulus MAASP:
Current Well Status: *Producing*	Date:			C-annulus MAASP:



Barrier Element Table

Barrier Element	Element Verification
Primary Well Barrier to Reservoir	
Cap Rock	Xxx Equivalent Mud Wt s.g.
7" Liner Cement	TOC xxx ft: Total Cmt length xxx ft
7" Liner Hanger/Packer	PT to xxx kPa w/ MW yy s.g.
7" Liner	PT to xxx kPa w/ MW yy s.g.
9-5/8" Casing (below Packer)	PT to xxx kPa w/ MW yy s.g.
9-5/8" Casing Cement (below Packer)	TOC xxx ft: Total Cmt length xxx ft
9-5/8" Production Packer	PT to xxx kPa w/ MW yy s.g.
4-½d Tubing	PT to xxx kPa w/ MW yy s.g.
TR SSSV Flapper	PT to xxx kPa w/ MW yy s.g.
Secondary Well Barrier to the Reservoir	
Formation Strength at packer	Xxx Equivalent Mud Wt s.g.
9-5/8" Cement (above packer)	TOC xxx ft: Total Cmt length xxx ft
9-5/8" Casing	PT to xxx kPa w/ MW yy s.g.
9-5/8" Casing Hanger seals	PT to xxx kPa w/ MW yy s.g.
9-5/8" Wellhead section	PT to xxx kPa w/ MW yy s.g.
9-5/8" Wellhead Annulus Valve	PT to xxx kPa w/ MW yy s.g.
Tubing Hanger Seals	PT to xxx kPa w/ MW yy s.g.
X-mas Tree Connector	PT to xxx kPa w/ MW yy s.g.
Hydraulic Master Valve	PT to xxx kPa w/ MW yy s.g.
X-mas Tree	PT to xxx kPa w/ MW yy s.g.

Well Integrity Notes:

1. the xx m of cement overlap inside the 13-3/8" is considered good cement and was verified by logging.

Figure F.1 — Example of well barrier schematic for operating phase

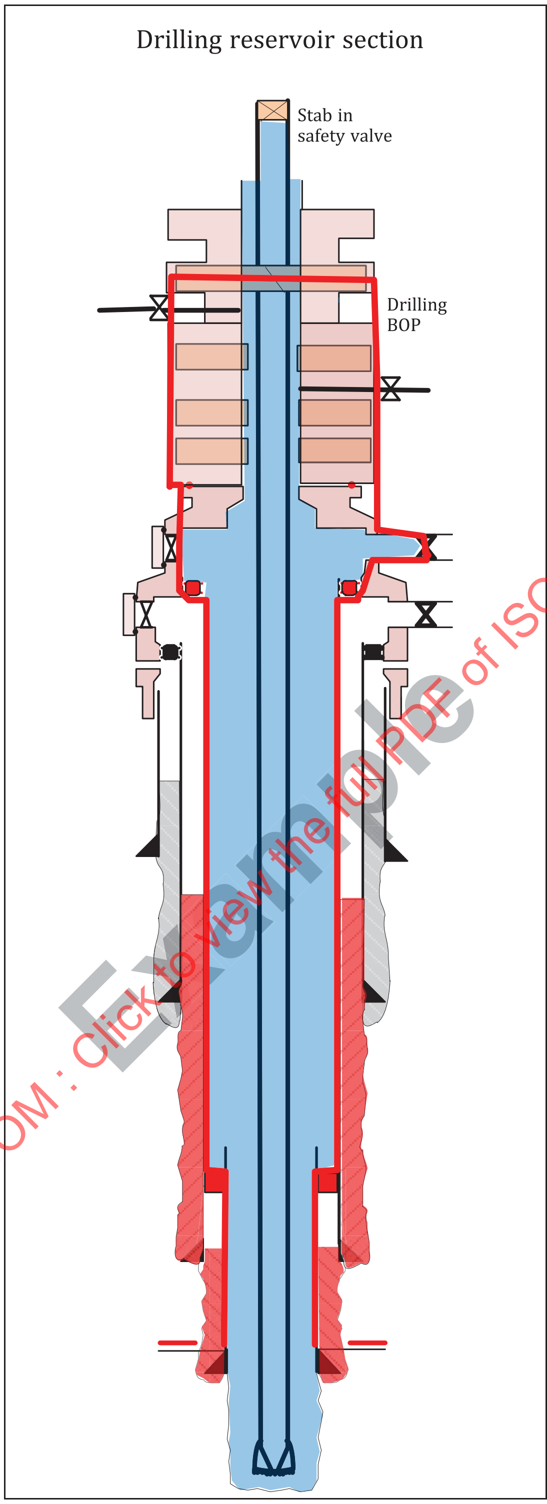


Figure F.2 — Example of well barriers during the construction phase

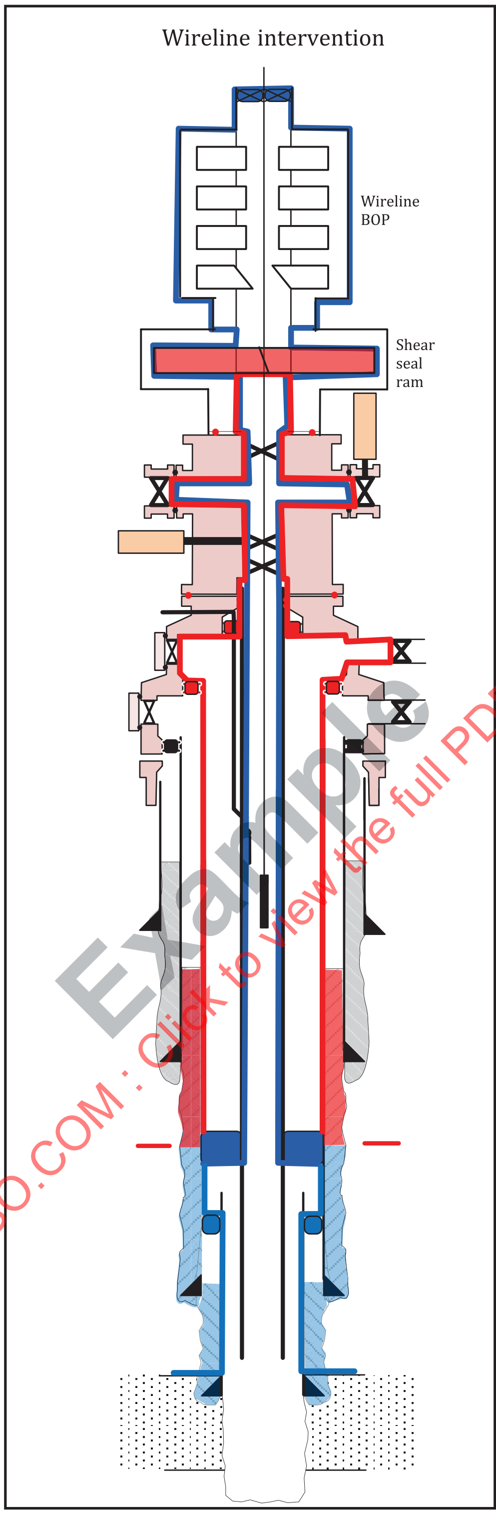


Figure F.3 — Example of well barriers during the intervention phase

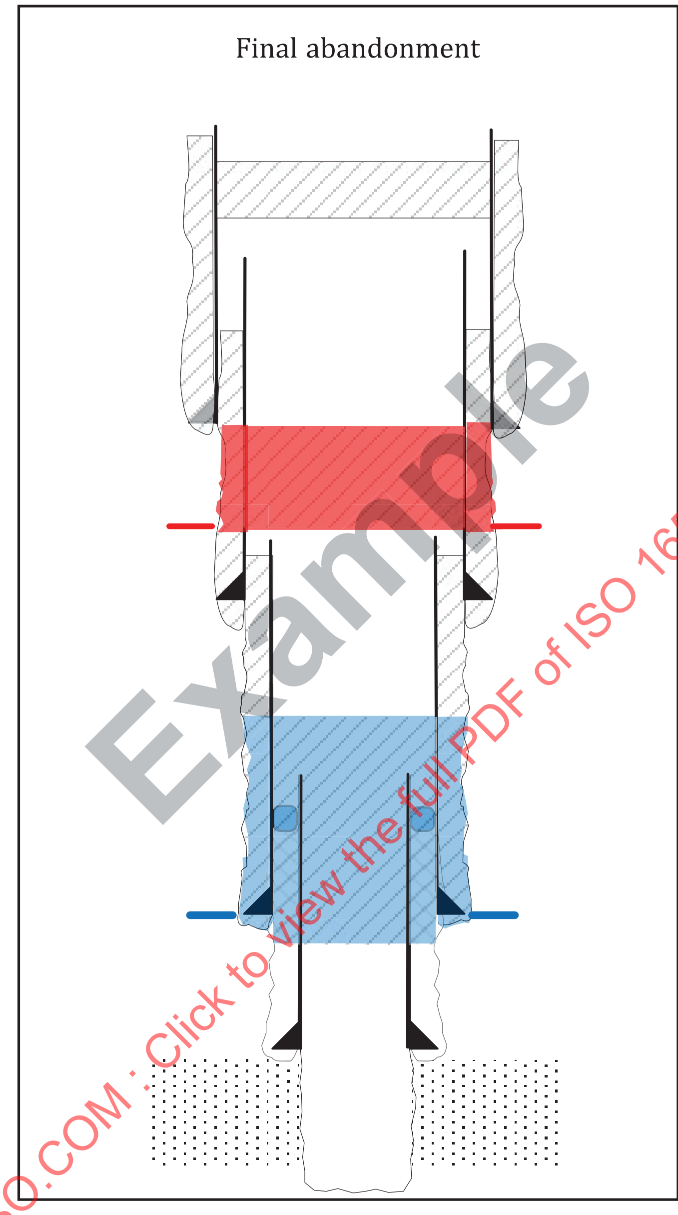


Figure F.4 — Example of the final well barriers after the abandonment phase

Annex G
(informative)

Example of performance standard for well barrier elements

Table G.1 — Example of performance standard for well barrier elements

Description	Performance monitoring requirement	Verification method	Acceptance criteria example
Well head/Tree visual inspection: There shall be no external leaks/weeps of the well head/tree, valve and instrument connections (visual inspection).	Acceptable visual inspection	No leaks	Zero
Wellhead/Tree valve operability: All wellhead/tree valves shall be operable in accordance with manufacturer defined specifications (number of turns).	Acceptable test/ operate on demand as per manufacturer specification	Number of turns	18 3/4 turns
Wellhead/Tree valve actuation: Actuated wellhead/tree valves shall close within the required time as defined by operator in the well hook up cause and effect requirements for shutdown based on API RP 14B.	Acceptable response test	Time	30 s
Wellhead/Tree valve leakage rate: The valve leakage rate is not greater than the corresponding allowable leakage rate as specified by the operator based on API RP 14B.	Acceptable test/ leak rate	Ambient volume/ time	Gas 0,43 Sm^3/min Liquid 400 Scm^3/min
Annulus safety valve (ASV) integrity: The ASV performs within the parameters specified by the operator based on API RP 14B.	Acceptable test operates on demand records available	Pressure limit	xx MPa
Annulus integrity management (1): The annulus pressures are to be within specified values for maximum allowable annulus surface pressure (MAASP)/trigger and minimum values.	Operates within MAASP records available	Pressure limit	xx MPa
Annulus integrity management (2): The annulus pressure monitoring equipment is calibrated correctly and alarms (where fitted) operate at the required set points or pressures are recorded manually on regular intervals.	Acceptable test operates on demand records available	Accuracy	Percentage
Annulus integrity management (3): The annulus pressures test is to be within the wells operating limits as defined by the operator.	Acceptable test operates on demand records available	Pressure test	xx MPa
Sub surface safety valves (SSSV) integrity: The SSSV performs within the parameters specified by the operator.	Acceptable test operates on demand	Leak test	Gas 0,43 Sm^3/min Liquid 400 Scm^3/min
Well plug(s) integrity test: The well plugs perform within the parameters specified by the operator.	Acceptable test operates on demand	Leak test	Zero
Gas-lift valve (GLV)/Tubing integrity test: The GLVs and tubing perform within the parameters specified by the operator.	GLV tubing to annulus test acceptable	Inflow test	Gas 0,43 Sm^3/min Liquid 400 Scm^3/min

Table G.1 *(continued)*

Description	Performance monitoring requirement	Verification method	Acceptance criteria example
Hanger neck seal, control line feed through, electrical feed through and drilling spool adaptor flange (DASF)/adaptor spool seal areas: The component pressures test is to be within the wells operating limit as specified by the operator.	Acceptable test operates on demand	Pressure test	xx MPa
Shutdowns of artificial lift pumps electrical submersible pumps (ESPs)/beam pumps/electrical submersible positive cavity pumps (ESPCPs)/positive cavity pumps (PCPS)/jet pumps gas-lift systems. Artificial lift systems that have capability to overpressure flow line/wellheads or other well components, shutdown test is to be within defined cause and effect diagram parameters.	Acceptable test operates on demand	Shutdown test	30 s
Location safety valve or production wing valve: Operates as defined in cause and effect diagram as defined by the operator.	Acceptable test operates on demand	Shutdown test	30 s
Operating limit of Injection wells: Maximum allowable injecting pressure as defined by the operator.	Operating limit of injection pressure based on MAASP of well bore	Pressure limit	xx MPa
Steam wells Maximum allowable pressure/temperature as defined by the operator.	Operating limit of injection pressure/ temperature based on MAASP and temperature limitations of well bore	Pressure + temperature limit	xx MPa/° C

Annex H
(informative)

Function testing by analysing hydraulic signature

H.1 Valve signature

The hydraulic signature of a valve is the pressure response when (slowly) pumping or bleeding off control-line fluid. Analysing this hydraulic signature can reveal mechanical problems.

Subsea tree valves often have a tell-tale to indicate valve position, which can be observed/verified by an ROV.

H.2 SCSSV

Figure H.1 shows the typical signature of an SCSSV. The change in the slope of the curve indicates that the flow-tube is moving. If there is no indication of flow-tube travel and a correspondingly smaller hydraulic volume pumped, the flow-tube can be stuck. It is good practice to keep a minimum of 6 895 MPa (1 000 psi) above the full opening pressure to ensure that the valve stays fully open when the well pressures change; refer to manufacturer's operating procedures for exact operating pressures.

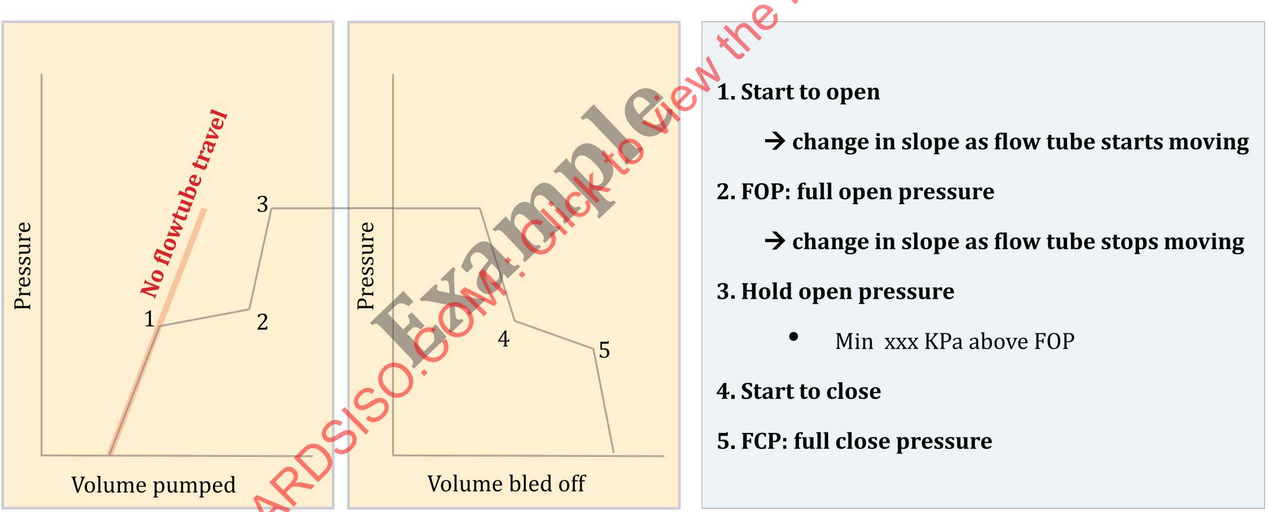


Figure H.1 — Typical signature of an SCSSV

A good hydraulic signature, however, is no guarantee that the valve is functioning correctly, since the flow tube and the flapper are not connected. If the flapper is stuck, or the torsion spring that assists flapper closure is broken, the flow tube can move all the way up to the closed position (resulting in a good hydraulic signature) but the flapper remains open. Therefore, analysing the hydraulic signature of an SCSSV does not prove flapper closure. The only way to prove that a flapper is closed is to demonstrate that the well is unable to flow.

If the SCSSV is operated from a wellhead control panel, it can be difficult to obtain a clear hydraulic signature. Under these circumstances, the control line may be disconnected from the panel and hooked up to a small portable independent control panel or even a hand pump.

H.3 Subsea tree

Figure H.2 shows the hydraulic signature of the production wing valve of a subsea tree that is being opened. The drop in supply pressure and the time it takes for the valve to open are good indicators. They can be compared with the signature from the original installation, and changes in the signature can be an indication that something is not functioning correctly.

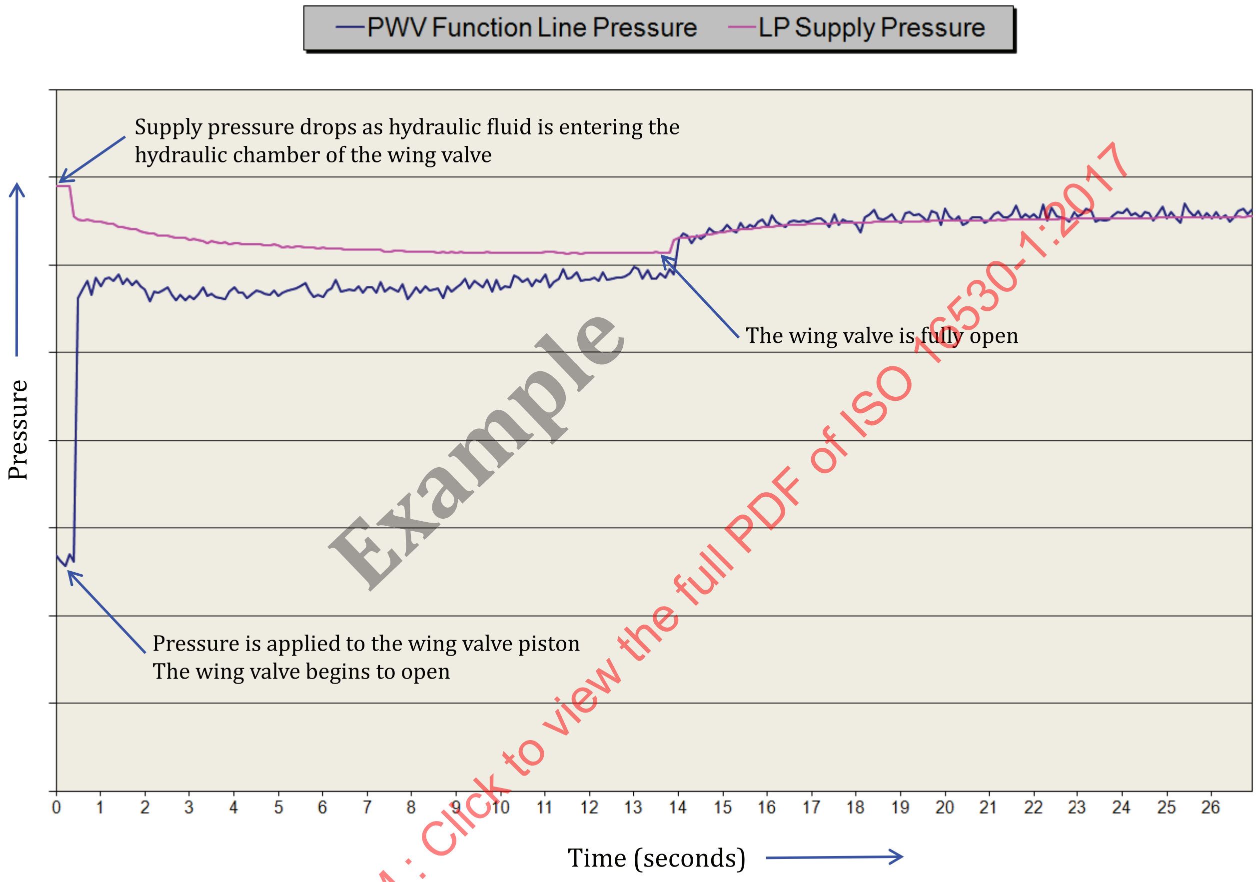


Figure H.2 — Signature of a production wing valve (PWV)