NORSOK Standard

D-010

Rev. 4, June 2013

Well integrity in drilling and well operations

Standards Norway
Strandveien 18, P.O. Box 242
N-1326 Lysaker
NORWAY

Telephone: + 47 67 83 86 00
Fax: + 47 67 83 86 01
Email: petroleum@standard.no
Website: www.standard.no/petroleum

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Foreword

NORSOK (The competitive standing of the Norwegian offshore sector) is the industry initiative to add value, reduce cost and lead time and eliminate unnecessary activities in offshore field developments and operations.

The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries. NORSOK standards are administered and issued by Standards Norway.

The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.

The NORSOK standards make extensive references to international standards. Where relevant, the contents of a NORSOK standard will be used to provide input to the international standardization process. Subject to implementation into international standards, the NORSOK standard will be withdrawn.

Note: Editorial corrections have been made[1]

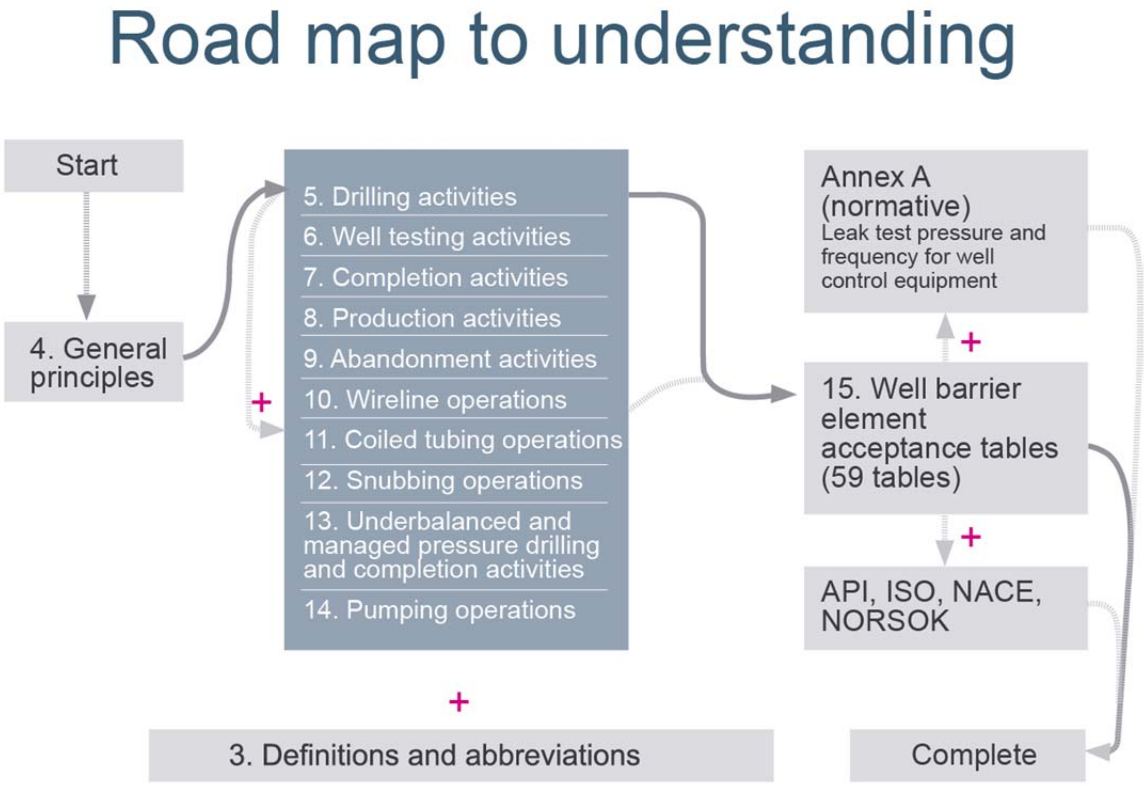
[1] Reference corrected for Table 38 in Clause 15.4 Table 4 (2013-10-31)

Introduction

This standard defines requirements and guidelines relating to well integrity in drilling and well activities. Well integrity is defined to be "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well". The standard focuses on establishing well barriers by use of WBE's, their acceptance criteria, their use and monitoring of integrity during their life cycle. The standard also covers well integrity management and personnel competence requirements. The standard does not contain any well or rig equipment specifications.

This revision was initiated to enhance the standard to include acceptance criteria for casing cement applied in the drilling, production and abandonment activities, managed pressure drilling and to include new WBE acceptance tables (formation, alternative material to cement, LWI equipment). The changes from the previous revision are not marked.

The user is encouraged to study the following "roadmap to understanding" to get a quick overview of the structure of this NORSOK standard and related requirements and guidelines:



1 Scope

This NORSOK standard focuses on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities and operations.

2 Normative and informative references

The following standards include provisions which, through reference in this text, constitute provisions of this NORSOK standard. Latest issue of the references shall be used unless otherwise agreed. Other recognized standards may be used provided they meet or exceed the requirements of the standards referenced below.

2.1 Normative references

The following documents shall be complied with:

NORSOK D-001, *Drilling facilities*

NORSOK D-002, *System requirements well intervention equipment*

NORSOK D-SR-007, *Well testing system*

2.2 Informative references

The following documents provide additional information intended to assist the understanding or use of this standard:

API Bull 5C2*, Performance Properties of Casing, Tubing, and Drill Pipe*

API TR 5C3, *Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing*

API RP 5C7*, Recommended Practice for Coiled Tubing Operations in Oil and Gas Well Services*

API RP 7G*, Recommended Practice for Drill Stem Design and Operation Limits*

API RP 14B*, Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*

API RP 10B-3 (R2010), *Recommended Practice on Testing of Deepwater Well Cement Formulations*

API RP 10B-4 (R2010), *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*

API RP 10B-5 (R2010), *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*

API RP 10B-6, *Recommended Practice on Determining the Static Gel Strength of Cement Formulations*

API RP 53*, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells*

API RP 92U, *Underbalanced Drilling Operations*

API Spec 5CT, *Specification for Casing and Tubing*

API Spec 5DP, *Specification for Drill Pipe*

API Spec 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Spec 6FA*, Fire Test for Valves*

API Spec 6FB*, Fire Test for End Connections*

API Spec 6FC*, Specification for Fire Test for Valve With Automatic Backseats*

API Spec 10A Specification for Cements and Materials for Well Cementing

API Spec 11V1, *Specification for Gas Lift Valves, Orifices, Reverse Flow Valves, and Dummy Valves*

API Spec 14A, *Specification for Subsurface Safety Valve Equipment*

API Spec 16RCD, *Drill Through Equipment-Rotating Control Devices*

API Spec 17D, *Design and Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment*

API Spec 53*, Blowout Prevention Equipment Systems for Drilling Wells*

ASTM D412*, Standard test Methods for Vulcanized Rubber and Thermoplastic Elastomers – Tension 1*

ASTM D471*, 12 Standard Test Method for Rubber Property – Effect of Liquids*

ASTM D2240*, 05(2010) Standard Test Method for Rubber Property – Durometer Hardness 1*

ASTM G111*, 97(2006) Standard Guide for Corrosion Tests in High Temperature or High Pressure Environment*

ISO/TR 10400:2007, *Petroleum and natural gas industries –- Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing*

ISO 10405*, Petroleum and natural gas industries – Care and use of casing and tubing*

ISO 10414-1*, Petroleum and natural gas industries – Field testing of drilling fluids – Part 1: Water-based fluids*

ISO 10414-2*, Petroleum and natural gas industries – Field testing of drilling fluids – Part 2: Oil-based fluids*

ISO 10416*, Petroleum and natural gas industries – Drilling fluids – Laboratory testing*

ISO 10417*, Petroleum and natural gas industries – Subsurface safety valve systems – Design, installation, operation and redress*

ISO 10423*, Petroleum and natural gas industries – Drilling and production equipment – Wellhead and christmas tree equipment*

ISO 10424-1, *Petroleum and natural gas industries – Rotary drilling equipment – Part 1: Rotary drill stem elements*

ISO 10426-1*, Petroleum and natural gas industries – Cements and materials for well cementing – Part 1: Specification*

ISO 10427-3, *Petroleum and natural gas industries – Equipment for well cementing – Part 3: Performance testing of cementing float equipment*

ISO 10432*, Petroleum and natural gas industries – Downhole equipment – Subsurface safety valve equipment*

ISO 10497*, Testing of valves – Fire type-testing requirements*

ISO 11960*, Petroleum and natural gas industries – Steel pipes for use as casing or tubing for wells*

ISO 11961*, Petroleum and natural gas industries – Steel drill pipe*

ISO 13533*, Petroleum and natural gas industries – Drilling and production equipment – Drill-through equipment*

ISO 13628-1*, Petroleum and natural gas industries – Design and operation of subsea production systems – Part 1: General requirements and recommendations*

ISO 13628-4*, Petroleum and natural gas industries – Design and operation of subsea production systems – Part 4: Subsea wellhead and tree equipment*

ISO 13628-7*, Petroleum and natural gas industries – Design and operation of subsea production systems – Part 7: Completion/workover riser systems*

ISO 13679, Petroleum and natural gas industries – Procedures for testing casing and tubing connections

ISO 14310*, Petroleum and natural gas industries – Downhole equipment – Packers and bridge plugs*

ISO/FDIS 14998*, Petroleum and natural gas industries – Downhole equipment – Completion accessories*

ISO 15156-1*, Petroleum and natural gas industries – Materials for use in H_2S-containing environments in oil and gas production – Part 1: General principles for selection of cracking-resistant materials*

ISO 17078-2, *Petroleum and natural gas industries – Drilling and production equipment – Part 2: Flow-control devices for side-pocket mandrels*

ISO 28781, *Petroleum and natural gas industries – Drilling and production equipment –Subsurface barrier valves and related equipment*

NORSOK Z-013, *Risk and emergency preparedness analysis*

NORSOK Z-015, *Temporary equipment - forms*

Norwegian Oil and Gas association, Guideline no. 117, *Recommended guidelines for Well Integrity*

TH Hill DS-1

UK Oil and Gas OP071, *Guidelines for the suspension and abandonment of wells, Issue 4, July 2012 and Guidelines on qualification of materials for the suspension and abandonment of wells*

3 Terms, definitions and abbreviations

For the purposes of this NORSOK standard the following terms, definitions and abbreviations apply.

3.1 Terms and definitions

3.1.1
A-annulus
annulus between the tubing and the production casing

3.1.2
abnormal pressure
formation or zones where the pore pressure is above the normal, regional hydrostatic pressure

3.1.3
activity
preparation for and implementation of operations

3.1.4
B-annulus
annuli between the production casing and the previous casing string

3.1.5
can
verbal form used for statements of possibility and capability, whether material, physical or casual

3.1.6
cement
collective term for cement and non-cementitious materials that is used to replace cement

3.1.7
common well barrier element
barrier element that is shared between the primary and secondary well barrier

3.1.8
critical activity or operation
activity or operation that potentially can cause serious injury or death to people, or significant pollution of the environment or substantial financial losses

3.1.9 critical casing cement
is defined as the casing cement in the following scenarios:

the production casing / liner, when set into/through a source of inflow with hydrocarbons;

the production casing / liner, when the same casing cement is a part of the primary and secondary well barriers;

wells with injection pressure which exceeds the formation integrity at the cap rock.

3.1.10
crossflow well barrier
a well barrier which prevents flow between two formation zones

3.1.11
deep water well
water depth exceeding 600 m

3.1.12
design factor
is the minimum allowable safety factor, which is expressed as the ratio between the rated strength of the material over the estimated maximum load

3.1.13
double block
two valves or other barrier elements in series above the seabed/surface

3.1.14
double block and bleed
two valves or other barrier elements in series above seabed/surface with bleed off capabilities between the two valves

3.1.15
electrical cable
wire consisting of one or more electrical conductors

3.1.16
energised fluids
liquefied gases or liquid containing gases

3.1.17
formation integrity pressure
collective term to describe strength of the formation. This can be either FIT/PIT or the interval between fracture breakdown pressure and fracture closure pressure

3.1.18
fracture closure pressure
pressure at which the fracture closes after the formation has been broken down. Fracture closure pressure equal to minimum formation stress

3.1.19
gas lift barrier
barrier envelope that prevents flow to the environment from an artificial/injected gas lift source

NOTE The source is volume of gas in the A-annulus above the gas lift injection valve or the annulus downhole safety valve.

3.1.20
high pressure high temperature well
well with expected shut-in pressure exceeding 690 bar, (10,000 psi), and a static bottom hole temperature higher than 150 ^{o}C

3.1.21
high pressure well
well with expected shut-in pressure exceeding 690 bar (10,000 psi)

3.1.22
high temperature well
well with expected static bottom hole temperature higher than 150 ^{o}C

3.1.23
hydrostatic pressure
the pressure exerted by a fluid at equilibrium due to the force of gravity

3.1.24
inflow test
defined differential created by reducing the pressure on the downstream side of the well barrier or well barrier element

3.1.25
kick tolerance
maximum influx volume that can be circulated out of well without breaking down the weakest zone in well

3.1.26
managed pressure drilling
an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore whilst drilling

3.1.27
may
verbal form used to indicate a course of action permissible within the limits of this NORSOK standard

3.1.28
minimum formation stress
is the fracture closing pressure

3.1.29
normal pressure
formation or zones where the pore pressure is equal to the normal regional hydrostatic pressure

3.1.30
open hole to surface well barrier
the shallowest well barrier that isolates exposed open hole annuli to the external environment

3.1.31
operation
sequence of planning and execution tasks that are carried out to complete a specific activity

3.1.32
permanent abandonment
well status, where the well is abandoned permanently and will not be used or re-entered again

3.1.33
permanent well barrier
a well barrier which permanently seals a source of inflow

3.1.34
pipe light
tripping mode where pressure forces acting upwards on the cross sectional area of the work string is larger than the weight of the string

3.1.35
plug
a device or material placed in the well with intention to function as a foundation or as a qualified well barrier element

3.1.36
plugging
operation of securing a well by installing required well barriers

3.1.37
pressure/leak testing
application of differential pressure to detect leaks in a well barrier, well barrier element or other objects that are designed to confine pressurised fluids (liquid or gas)

3.1.38
primary well barrier
first well barrier that prevents flow from a potential source of inflow

3.1.39
procedure
series of steps that describes the execution of a task

3.1.40
pumping
injection or flow of a fluid from surface into the well

3.1.41
rated working pressure
the maximum internal pressure equipment is designed to contain

3.1.42
reservoir
a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water (same definition as source of inflow)

3.1.43
riser margin
additional fluid density required to compensate for the differential pressure between the fluid in the riser and seawater in the event of a riser disconnect

3.1.44
risk
combination of the probability of occurrence of harm and the severity of that harm

NOTE Risk may be expressed qualitatively as well as quantitatively. Probability may be expressed as a probability value (0-1, dimensionless) or as a frequency, with the inverse of time as dimension.

3.1.45
risk analysis
structured use of available information to identify hazards and to describe risk

NOTE 1 The risk analysis term covers several types of analyses that will all assess causes for and consequences of accidental events, with respect to risk to personnel, environment and assets. Examples of the simpler analyses are SJA, FMEA, preliminary hazard analysis, HAZOP, etc.

NOTE 2 Quantitative analysis may be the most relevant in many cases, involving a quantification of the probability and the consequences of accidental events, in a manner which allows comparison with quantitative RAC.

3.1.46
risk assessment
overall process of performing a risk assessment including: Establishment of the context, performance of the risk analysis, risk evaluation, and to assure that the communication and consultations, monitoring and review activities, performed prior to, during and after the analysis has been executed, are suitable and appropriate with respect to achieving the goals for the assessment

3.1.47
secondary well barrier
second well barrier that prevents flow from a potential source of inflow

3.1.48
section design pressure
the maximum absolute pressure expected in the well at surface / wellhead whilst drilling a hole section

3.1.49
shall
verbal form used to indicate requirements strictly to be followed in order to conform to this NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties

NOTE The deviation process for handling of deviations and non-conformity with “shall” requirements and “should” guidelines in this NORSOK standard shall be in accordance with responsible party’s system for handling of deviations. These systems shall describe procedures for how to deviate from requirements and guidelines listed in the regulatory regulations with guidelines and the responsible party’s steering documentation.

3.1.50
shallow gas
permeable gas formation(s) which are penetrated prior to installing the surface casing and BOP

NOTE The gas can be normally pressured or abnormally pressured.

3.1.51
should
verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required

NOTE The deviation process for handling of deviations and non-conformity with “shall” requirements and “should” guidelines in this NORSOK standard should be in accordance with responsible party’s system for handling of deviations. It is assumed that these systems describe procedures for how to deviate from requirements and guidelines listed in the regulations with guidelines and the responsible party’s steering documentation.

3.1.52
simultaneous activities
activities that are executed concurrently on the same installation such as production activities, drilling and well activities, maintenance and modification activities and critical activities

3.1.53
source of inflow
a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water (same definition as reservoir)

NOTE Hydrocarbons are movable unless they are residual or have extremely high viscosity (i.e. tar).

3.1.54
suspension
well status, where the well operation is suspended without removing the well control equipment. This applies to wells under construction or intervention

EXAMPLE Rig skidded to do short term work on another well, strike, WOW, waiting on equipment, etc.

3.1.55
surface casing
the casing which first allows installation of the BOP

3.1.56
temporary abandonment – with monitoring
well status, where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested

NOTE If the criteria cannot be fulfilled, the well shall be categorized as a temporary abandoned well without monitoring.

3.1.57
temporary abandonment – without monitoring
well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested

3.1.58
through tubing drilling and completion
drilling and completing operations conducted through the in situ tubing

3.1.59
trip margin
increase in fluid density to compensate for pressure reduction due to swab effects while pulling out of hole

3.1.60
ultimate well barrier stage
final stage of a well barrier element activation sequence which normally includes closing a shearing device

3.1.61
under balanced drilling
a drilling activity employing equipment and controls where the pressure exerted in the wellbore is intentionally less than the pore pressure in any part of the exposed formations

3.1.62
well barrier
envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment

3.1.63
well barrier element
a physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier

3.1.64
well barrier element acceptance criteria
technical and operational requirements and guidelines to be fulfilled in order to verify the well barrier element for its intended use

3.1.65
well control
collective expression for all measures that can be applied to prevent uncontrolled release of wellbore fluids to the external environment or uncontrolled underground flow

3.1.66
well control incident
incident in which a failure of barrier(s) or failure to activate barrier(s), results in an unintentional flow of formation fluid into the well, into another formation or to the external environment

3.1.67
well control action procedure
sequence of planned actions/steps to be executed when a well barrier fails

NOTE This normally describes the activation of the secondary well barrier, e.g. shut-in of well.

3.1.68
well design pressure
the maximum absolute pressure expected in the well at surface/wellhead

3.1.69
well integrity
application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well

3.1.70
wireline
collective term for slickline, braided line, and electric line

3.2 Abbreviation

AC	acceptance criteria
ACV	annulus circulation valve
AMV	annulus master valve
APB	annulus pressure build-up
ASV	annulus safety valve
AWV	annulus wing valve
BHA	bottom hole assembly
BHP	bottom hole pressure
BMV	bleed monitoring valve
BOP	blow out preventer
BPV	back pressure valve
CT	coiled tubing
DHPG	downhole pressure gauge
DHSV	downhole safety valve
DIV	downhole isolation valve
DP	dynamically positioned
EAC	(well barrier) element acceptance criteria
ECD	equivalent circulating density
ESD	emergency shut-down
ESDV	emergency shut-down valve
FBP	formation breakdown pressure
FPP	fracture propagation pressure
FRP	fracture reopening pressure
FCP	fracture closure pressure
HMV	hydraulic master valve
HP	high pressure
HPHT	high pressure and high temperature
HT	high temperature
HSE	health, safety and environment
HXT	horizontal x-mas tree

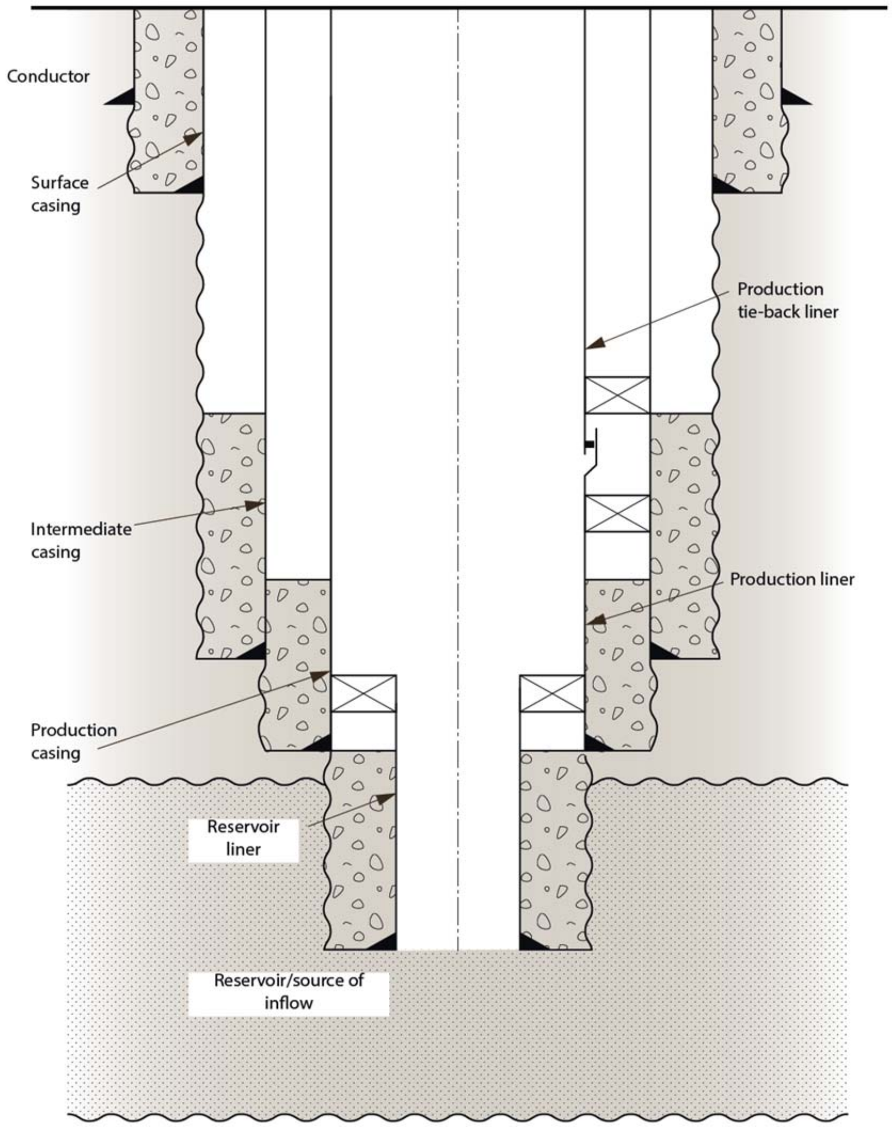
IADC	international association of drilling contractor’s
ID	internal diameter
IWCF	international well control forum
ISO	international standardization organization
IT	inflow test
KV	kill valve
LHD	low head drilling
LLV	lower lubricator valve
LMRP	lower marine riser package
LOT	leak-off test
LRP	lower riser package
LWD	logging while drilling
LWI	light well intervention
MAASP	maximum allowable annulus surface pressure
MD	measured depth
MMV	manual master valve
MOC	management of change
MPD	managed pressure drilling
MPI	magnetic particle inspection
MWDP	maximum well design pressure
NRV	non-return valve
OD	outer diameter
PIT	pressure integrity test
PMV	production master valve
PRV	pressure relief valve
PSD	production shut-down
PT	pressure test
PWV	production wing valve
RCD	rotating control device
R/U	rig up
RIH	running in hole
ROV	remote operated vehicle
RV	retainer valve
RWP	rated working pressure
R/D	rig down
SDP	section design pressure
SSR	shear-seal ram
SSTT	subsea test tree
SSW	subsea well
STT	surface test tree

SV	swab valve
TCP	tubing conveyed perforating
TOC	top of cement
UB	under balanced
UBD	under balanced drilling
ULV	upper lubricator valve
VXT	vertical x-mas tree
WAG	water alternating gas injector
WBE	well barrier element
WBS	well barrier schematic
WDP	well design pressure
WHP	well head pressure
WL	wireline
WOW	waiting on weather
WP	working pressure
XLOT	extended leak-off test
XOV	cross-over valve
XT	x-mas tree (production/injection tree)

3.3 Casing/liner naming convention

The figure illustrates the naming conventions for the various casing and liners in the following sections.

Casing illustration



4 General principles

4.1 General

This section describes generic principles, requirements and guidelines applicable to the specific well activities and operations described in the sections to follow.

If there is a conflict between this Section 4 and the following sections, the specific section shall apply.

4.2 Well barriers

4.2.1 Defining well barriers

The well barriers shall be defined prior to commencement of an activity or operation by identifying the required well barrier elements (WBE) to be in place, their specific acceptance criteria and monitoring method.

4.2.2 Well barrier schematics

Well barrier schematics (WBS) shall be prepared for each well activity and operation (see figure 4.2.2.)

A WBS should be made:

a) when a new well component is acting as a WBE;
b) for illustration of the completed well with XT (planned and as built);
c) for recompletion or workover on wells with deficient WBEs; and
d) for final status of permanently abandoned wells.

It is not necessary to make a new schematic for different types of running assemblies when the elements and activation of secondary well barriers are not affected.

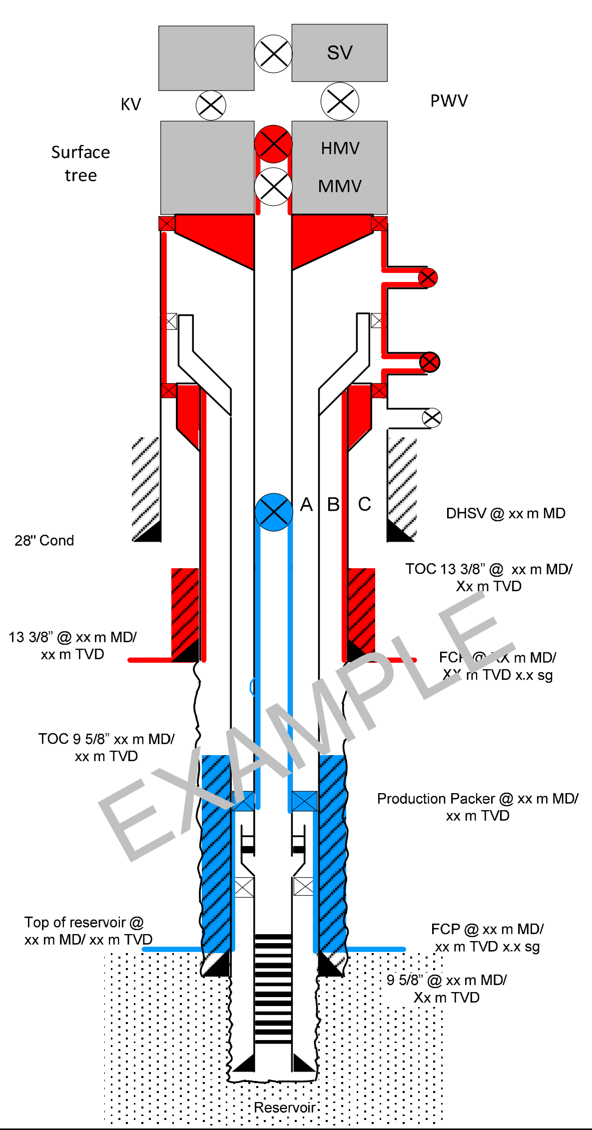
The WBS should contain the following information:

e) A drawing illustrating the well barriers, with the primary well barrier shown with blue colour and secondary well barrier shown with red colour.
f) The formation integrity when the formation is part of a well barrier.
g) Reservoirs/potential sources of inflow.
h) Tabulated listing of WBEs with initial verification and monitoring requirements.
i) All casings and cement. Casing and cement (including TOC) defined as WBEs should be labelled with its size and depth (TVD and MD).
j) Component should be shown relatively correct position in relation to each other.
k) Well information: field/installation, well name, well type, well status, well/section design pressure, revision number and date, “Prepared by”, “Verified/Approved by”.
l) Clear labelling of actual well barrier status – planned or as built.
m) Any failed or impaired WBE to be clearly stated.
n) A note field for important well integrity information (anomalies, exemptions, etc.).

Examples of WBSs are presented in this standard for selected situations. These WBSs are examples and describe one possible solution for defining and illustrating the well barriers with WBEs:

o) The primary well barrier is shown in its normal working stage, where the WBEs are exposed to the wellbore pressure.
p) The secondary well barrier is shown in its ultimate stage, where a WBE (e.g. shear/seal ram/valve) is activated to close the well barrier envelope.

Well information (as built)	
Field/Installation:	
Well name:	
Well type:	Producer
Well status:	Shut-in
Well design pressure:	xx bar
Revision number:	Version 1.0
Date prepared/revised:	
Prepared by: Verified/Approved by:	



Note 1: Well shut-in due to tubing leak above DHSV.

Nomenclature:
PT: Pressure test
IT: Inflow test
FCP: fracture closure pressure
XLOT: extended leak off test
AC: acceptance criteria

Well barrier elements	EAC table	Verification	Monitoring
Primary well barrier			
In-situ formation (cap rock)	51	FCP: x.x s.g. Based on field model	n/a after initial verification
Casing cement (9 5/8")	22	Length: xx mMD Cement bond logs	Daily pressure monitoring of B-annulus
Casing (9 5/8")	2	PT: xx bar with x s.g. EMW	n/a after initial verification
Production packer	7	PT: xx bar with x s.g. EMW	Continuous pressure monitoring of A-annulus
Completion string	25	PT: xx bar with x s.g. EMW	Continuous pressure monitoring of A-annulus See Note 1.
Completion string component (Chemical Injection valve)	29	PT: xx bar with x s.g. EMW	Periodic leak testing AC DHSV: xx bar/xx min
Downhole safety valve (incl. control line)	8	IT: xx bar (DHSV) PT: xx bar (control line)	Periodic leak testing AC DHSV: xx bar/xx min
Secondary well barrier			
In-situ formation (13 3/8" shoe)	51	FCP: x.x s.g. Based on XLOT	n/a after initial verification
Casing cement (13 3/8")	22	Length: xx mMD Method: Volume control	Daily pressure monitoring of C-annulus
Casing (13 3/8")	2	PT: xx bar with x s.g. EMW	Daily pressure monitoring of C-annulus
Wellhead (Casing hanger with seal assembly)	5	PT: xx bar	Daily pressure monitoring of C-annulus/ Periodic leak testing
Wellhead / annulus access valves	12	PT: xx bar	Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals and neck seal)	10	PT: xx bar	Periodic leak testing
Wellhead (WH/XT Connector)	5	PT: xx bar	Periodic leak testing
Surface tree	33	PT: xx bar	Periodic leak testing of valves AC: xx bar/xx min

Figure 4.2.2 – Platform production/injection/observation well capable of flowing

4.2.3 Well barrier requirements

4.2.3.1 Function and number of well barriers

The following number of well barriers shall be in place:

Minimum number of well barriers	Source of inflow
One well barrier	a) Undesirable cross flow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapour)
Two well barriers	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

4.2.3.2 Well barrier selection and construction principles

The well barriers shall be designed, selected and constructed with capability to:

a) withstand the maximum differential pressure and temperature it may become exposed to (taking into account depletion or injection regimes in adjacent wells);
b) be pressure tested, function tested or verified by other methods;
c) ensure that no single failure of a well barrier or WBE can lead to uncontrolled flow of wellbore fluids or gases to the external environment;
d) re-establish a lost well barrier or establish another alternative well barrier;
e) operate competently and withstand the environment for which it may be exposed to over time;
f) determine the physical position/location and integrity status at all times when such monitoring is possible; and
g) be independent of each other and avoid having common WBEs to the extent possible.

During operations the following apply:

h) The double block and bleed principle shall be fulfilled for all equipment above seabed/surface, which can be exposed to well pressure, i.e. two valves in series in all in-/outlets from the well.
i) When a workstring penetrates the well barrier, one of the WBEs should be able to shear the workstring and seal the wellbore after having sheared the string.
j) All non-shearable components in the work-string shall be identified.
k) When running non-shearable components through the BOP, there shall be procedures in place for handling a well control situation.
l) When running long non-shearable assemblies, there shall be an element (e.g. annular preventer) installed that can seal the wellbore against any size assembly that penetrates the well barrier.

4.2.3.3 Casing cement in primary and secondary well barriers

The same casing cement can become WBEs in both the primary and secondary well barriers contingent upon the acceptance criteria in EAC 22 are fulfilled. The acceptance criteria states there shall be 2 x 30m MD intervals of bonded cement, obtained by logs which have been verified by qualified personnel.

When this criterion is fulfilled, the two distinct intervals will be elements in the primary and secondary well barriers, respectively. See figure 4.2.3.3.1. The casing cement is not defined as a common WBE.

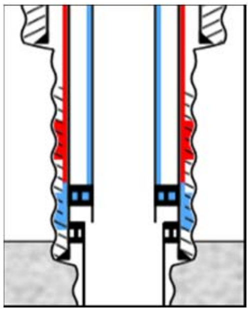


Figure 4.2.3.3.1 – Primary and secondary well barriers

This may be required for situations where the formation integrity at the previous casing shoe is insufficient to contain the wellbore pressure in the event of a leak through the casing cement.

4.2.3.4 Common well barrier elements

For some well activities it is not possible to establish two independent well barriers.

When a common WBE exists, a risk analysis shall be performed and risk reducing measures applied. This shall include additional precautions and acceptance criteria when qualifying and monitoring the common WBE.

Example 1: The wing valves in a tree during intervention work are part of both the primary and the secondary well barriers and are therefore common WBEs.

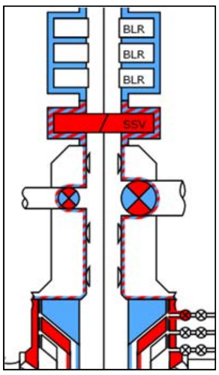


Figure 4.2.3.4.1 – Common barrier – wing valves

Example 2: The cement plug can be a common WBE in some situations, e.g. when a continuous cement plug (see EAC 24) is set inside casing and where the casing cement is verified as WBEs (see 4.2.3.3.)

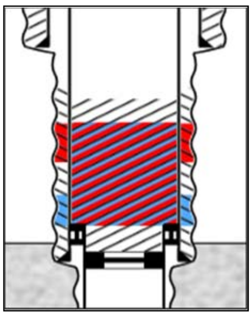


Figure 4.2.3.4.2 – Common barrier – cement plug

4.2.3.5 Verification of well barrier elements

When a WBE has been installed, its integrity shall:

a) be verified by means of pressure testing by application of a differential pressure; or
b) when a) is not feasible, be verified by other specified methods.

Well barrier elements that require activation shall be function tested.

A re-verification should be performed if:

c) the condition of any WBE has changed, or;
d) there is a change in loads for the remaining life cycle of the well (drilling, completion and production phase).

4.2.3.6 Pressure testing of well barriers

4.2.3.6.1 General

Pressure testing of well barriers or WBEs shall be performed:

a) before it can become exposed to a pressure differential in its operating phase;
b) after replacement of pressure confining components of a WBE;
c) when there is a suspicion of a leak;
d) when an element will be exposed to different pressure/load than it was originally tested to;
e) if the barrier element has been accidently exposed to differential pressure/load higher than original well design values;
f) periodically, see EAC tables in section 15 for specific requirements.

During pressure testing, the volume downstream of the element being tested should be monitored when feasible.

4.2.3.6.2 Acceptable leak rates

The acceptable leak rate shall be zero, unless specified otherwise in EAC's. For practical purposes acceptance criteria should be established to allow for volume, temperature effects, air entrapment and media compressibility. For situations where the leak-rate cannot be monitored or measured, the criteria for maximum allowable pressure leak (stable reading) shall be established.

4.2.3.6.3 Pressure test direction

The test pressure should be applied in the direction of flow towards the external environment. If this is not possible or introduces additional risk, the test pressure can be applied against the direction of flow towards the external environment, provided that the WBE is constructed to seal in both flow directions.

4.2.3.6.4 Test pressure values and duration

A low pressure test to 15–20 bar for minimum 5 minutes stable reading should be performed prior to high pressure testing in the drilling, completion and intervention activities. For periodic testing of wells in production/injection phase, a low pressure test is not required.

The high pressure test value shall be equal to, or exceed the maximum differential pressure that the WBE may become exposed to. Static test pressure shall be observed and recorded for minimum 10 minutes with stable reading.

In the production/injection phase, a 70 bar pressure differential should be applied for all WBEs with an allowable leak rate. Less differential pressure (i.e. if the well pressure is less) may be used provided that the allowable leak rate is changed proportionally.

Inflow tests should last for a minimum of 30 minutes with stable reading (or longer due to large volumes, high compressibility fluids, or temperature effects).

The test pressure values shall not exceed the well design pressure or rated working pressure of exposed WBEs.

The following should apply to qualify a pressure test:

a) consider the monitored volume when setting the test acceptance criteria;
b) establish maximum acceptable deviation from test pressure (x bar deviation from test pressure, e.g. 5 bar for a 345 bar test);
c) establish maximum allowable pressure variation over the defined time interval (e.g. 1% or 3,45 bar for a 345 bar test over 10 minutes);
d) A condition for the criteria in b) and c) is that the pressure change over time ($\Delta p/\Delta t$) is declining.

4.2.3.6.5 Inflow testing during drilling and well activities

Inflow testing is performed to verify the WBE’s ability to withstand a pressure differential, e.g. when displacing the well to underbalanced fluid in preparation for subsequent operations such as completion, well testing, deep water riser disconnect, drilling out of casing below a permeable higher pressure zone, etc.

The execution of an inflow test shall be described by a detailed procedure, which should contain the following information:

a) an identification of the WBEs to be tested;
b) identification of the consequences of a leak;
c) the risk of inconclusive results due to large volumes, temperature effects, migration, etc.;
d) a plan of action in the event that leak occurs or if the test is inconclusive;
e) a schematic diagram showing the configuration of test lines and valve positions;
f) all operational steps and decision points;
g) defined acceptance criteria for the test.

The following apply for the execution of an inflow test:

h) the consequences of a failed inflow test shall be evaluated;
i) where practicable, a pressure test shall be applied to the WBE to be inflow tested;
j) the secondary well barrier shall be tested to ensure ability to withstand differential pressure should the inflow test fail;
k) volume and pressure control shall be maintained at all times during displacement and testing;
l) during inflow testing it shall be possible to displace the well back to overbalanced fluid at indication of flow or in case of inconclusive results;
m) during displacement, non-shearable components shall not be placed across the BOP shear ram;
n) displacement to a underbalanced fluid shall be performed with a closed BOP and constant bottom hole pressure;
o) when the displacement is complete, the well shall be closed in without reducing the bottom hole pressure;
p) the bottom hole pressure shall be reduced in steps to a pre-defined differential pressure;
q) the pressure development shall be monitored for a specified time period for each step.

4.2.3.6.6 Function testing of well barriers

A function test of WBE(s) requiring activation shall be performed:

a) prior to installation (subsea/downhole equipment);
b) after installation;
c) if subjected to abnormal loads;
d) after repairs;
e) periodically, see EAC tables in section 15 for specific requirements.

4.2.3.6.7 Testing of formation

Rock mechanical data shall be systematically acquired in order to ensure well integrity in the drilling, production/injection and abandonment phases.

The chosen formation integrity test method shall be determined by the objective of the test. The most common methods are:

Table 1 – Methods for determining formation integrity

Method	Objective	Comment
Pressure/formation integrity test (PIT/FIT)	To confirm that the formation/casing cement is capable of supporting a pre-defined pressure	Application of a pre-determined pressure to the formation and observe if stable.
Leak-off test (LOT)	To establish the pressure the wellbore wall/casing cement is actually capable of supporting	The test is stopped once a deviation from the linear pressure vs. volume curve is observed.
Extended leak-off test (XLOT)	Determine the minimum in-situ formation stress.	The test propagates a fracture into the formation and establishes the fracture closure pressure (FCP).

Sufficient formation integrity shall be defined and documented in order to qualify formation as a WBE. The following apply:

Table 2 – Formation integrity requirements

<table>
<tr><th rowspan="2">Well type/activities</th><th colspan="2">Minimum formation integrity</th></tr>
<tr><th>New wells</th><th>Existing wells</th></tr>
<tr><td>Exploration wells (all activities including permanent abandonment)</td><td colspan="2" rowspan="2">Formation integrity can be obtained by PIT/FIT or LOT. The measured values shall exceed the section design pressure taking hydrostatic pressure into account.</td></tr>
<tr><td>Production wells – drilling activities and activities with mud in hole</td></tr>
<tr><td>Production wells – completion activities with solid-free fluid, production/injection and abandonment activities</td><td>Minimum formation stress/fracture closure pressure (FCP) shall exceed the maximum wellbore pressure at formation depth. The expected wellbore pressure shall as a minimum be based on the reservoir pressure (minus hydrostatic pressure) for producers and maximum injection pressure (plus hydrostatic pressure) for injectors.</td><td>The formation integrity pressure (in the interval between LOP and FCP, see figure below) used in the original design can be used. The original design values shall be re-assessed prior to permanent abandonment of the well(s).</td></tr>
</table>

The graph below shows typical pressure behaviour when performing an extended leak-off test in a non-permeable formation.

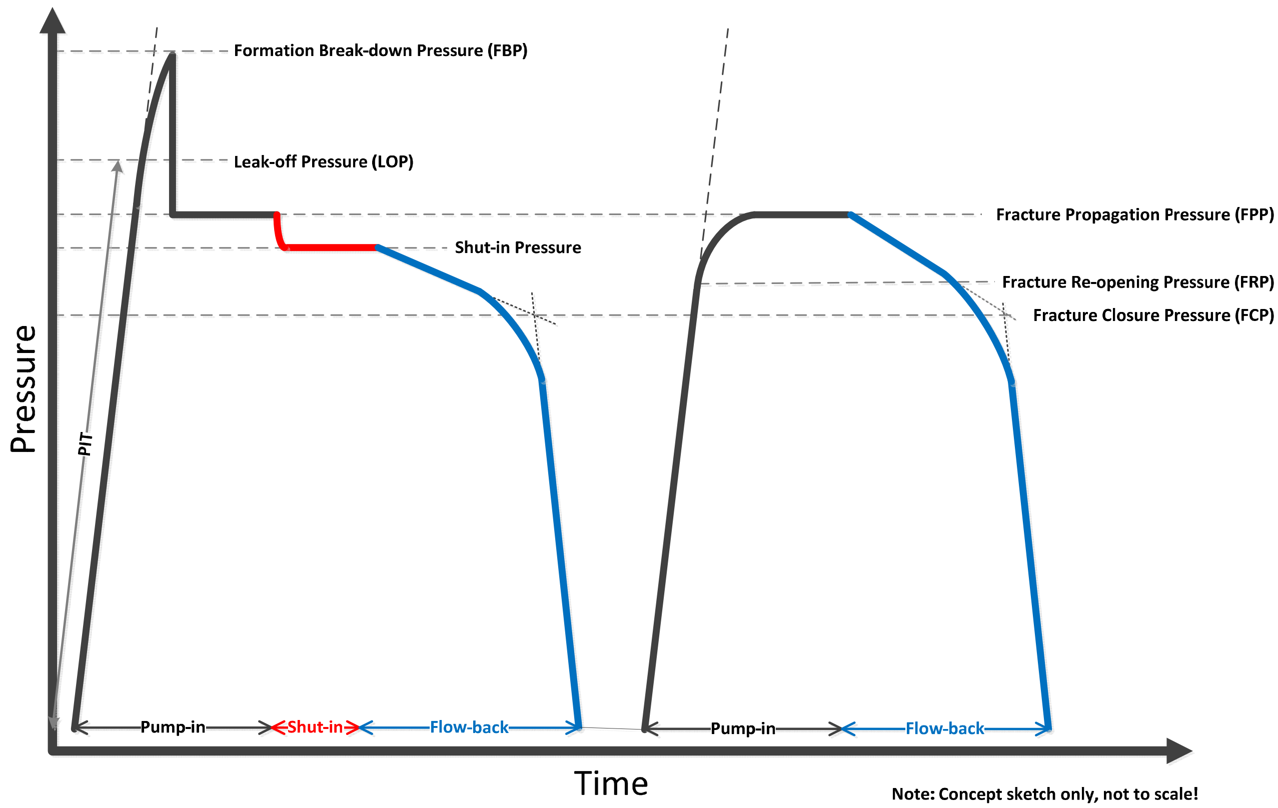


Figure 4.2.3.6.7.1 – XLOT pressure graph

4.2.3.6.8 Documentation of pressure and function testing of well barriers

All well integrity tests shall be documented and accepted by the person responsible for the operation.

The test records shall contain the following:

Table 3 – Pressure and function test documentation

Documentation	Pressure tests	Function test
a) field and wellbore name;	X	X
b) proper scale of test chart;	X	
c) type of test;	X	X
d) test/differential pressure;	X	
e) test fluid;	X	
f) system or components tested;	X	
g) estimated volume of pressurized system;	X	
h)volume pumped and bled back;	X	
i) time and date;	X	X
j) test evaluation period;	X	
k) observed pressure trend/observed leak rate;	X	
l) acceptance criteria for the test;	X	X
m) result of test (passed or failed);	X	
n) activation time or turns required for closure of valves.		X

4.2.3.7 Well barrier monitoring

All parameters relevant for preventing uncontrolled flow from the well shall be monitored.

Methods and frequency for verifying the condition of the well barrier or WBEs shall be defined and documented.

Volume control of fluid shall be maintained at all times when the fluid is a well barrier.

The pressure in all accessible annuli shall be monitored and recorded.

All instrumentation used for required monitoring of parameters shall be frequently checked and calibrated.

Use of alarms, automated sequences and shut down shall be evaluated based on risk and needed response time. Human Machine Interface assessments should be performed in design.

4.2.3.8 Well barrier impairment

Situations where the function of the well barrier is weakened, but still regarded as acceptable shall be documented, updated on the WBS and approved.

4.2.4 Element acceptance criteria (EAC) tables

Well barrier element acceptance criteria shall be in place for all WBEs used.

General technical and operational requirements and guidelines relating to WBEs are collated in the EAC tables in Section 15, which shall be applicable for all type of activities and operations.

A new EAC table shall be developed in cases where an EAC table does not exist for a specific WBE. The level of detail shall be defined by the user.

The described acceptance criteria and listed references in the tables are for selection and installation purposes and do not replace the technical and functional requirements that standards or the operating company specify for the equipment. The references listed in column "See" is intended for information purposes. The recommended format for the EAC tables is:

Table 4 – EAC table description

Features	Acceptance criteria	See
A. Description	This is a description of the WBE	
B. Function	This describes the main function of the WBE	
C. Design (capacity, rating, and function), construction and selection	For WBEs that are constructed in the field (e.g. drilling fluid, cement), this should describe a) design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used, b) construction requirements for the WBE or its sub-components, and will in most cases consist of references to normative standards. For WBEs that are pre-manufactured (production packer, DHSV), the focus should be on selection parameters for choosing the right equipment and proper field installation	Name of specific references
D. Initial test and verification	This describes the methodology for verifying the WBE being ready for use and being accepted as part of a well barrier	
E. Use	This describes proper use of the WBE in order for it to maintain its function during execution of activities and operations	
F. Monitoring (regular surveillance, testing and verification)	This describes the methods for verifying that the WBE continues to be intact and fulfils the design criteria	
G. Common WBE	This describes additional criteria to the above when this element is a common WBE	

4.2.5 Well control equipment and arrangements

Equipment arrangement drawings and flow diagrams for well control equipment shall be easily accessible for operators of this equipment such that it is possible to determine the position of a tubular joint relative to the shear rams/valves at all times. These drawings and flow diagrams should include:

a) geometrical description (location, size, distances to rig floor, distances between rams, etc.);
b) operational limitations (pressure, temperature, type of fluid, flow rates, etc.);
c) overview of the fluid circulation system (pump, including choke and kill manifold).

4.2.6 Well control action procedures

There shall be a plan for activating well barrier(s)/WBEs (well control action procedure), prior to commencement of all well activities and operations. The operator and the contractor shall ensure all involved personnel are familiar with the well control action procedures.

A well control bridging document between operator and contractor shall be prepared defining:

a) well control roles and responsibilities during the operation;
b) shut-in procedures;
c) methods for re-establishing well barriers:
   1) activation of alternative WBEs;
   2) kill procedures;
   3) normalization.
d) specific well control configuration for the well activity (including ram configuration).

In the event of a failure or loss of a well barrier, immediate measures shall be taken to prevent escalation of the situation. The situation shall then be normalized by restoring the well barrier or establishing an alternative well barrier before activities or operations can be resumed.

Activation of the shear rams/shear valves or other shearing devices shall only take place when testing the equipment or when there is an emergency situation and no other options exist but to cut and seal.

4.2.7 Onsite drills

Regular and realistic drills pertaining to on-going or up-coming operations shall be conducted to train involved personnel in detection and prevention of a lost well barrier. The objective of the drill shall be pre-defined. Pass/fail criteria for all key well control and safety drills shall be established. All relevant onsite personnel with emergency duties should be involved in the drills. The drills should be repeated with sufficient frequency to achieve the acceptable response. All drills shall be approved, evaluated for improvements and documented.

4.2.8 Well barrier re-establishment

4.2.8.1 Well barrier contingency

There shall be a contingency procedure which describes the steps required to re-establish a lost WBE or the establishment of an alternative WBE for the most likely and critical incident scenarios (e.g. kick, fluid loss, leak in intervention pressure control equipment).

4.2.8.2 Re-establishment of fluid well barrier

The methods for killing the well or re-establishing a fluid well barrier shall be defined and described prior to execution of activities where the fluid column is one of the well barriers or is defined to be a contingency well barrier.

Sufficient amount of materials and fluid to build necessary kill volumes shall be available prior to commencing well killing operation.

The preferred kill method for the different scenarios shall be described (e.g. “Driller’s”, “Wait and Weight”, “Volumetric” or “Bullheading” method).

Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a “Killsheet”.

4.3 Well design

4.3.1 Objective

A well design process shall be carried out for:

a) construction of new wells;
b) alteration, changes or modification to existing wells (i.e. from exploration to production or from producer to injector or vice versa);
c) changes in the well design basis or premises (e.g. life extension, increased pressure exposure, flow media).

All components shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations.

The design process shall cover the complete well or section lifespan encompassing all phases from installation to permanent abandonment and include the effects of material deterioration.

The design basis and design margins shall be known and documented.

Weak-points and operational limits related to design shall be identified and documented.

The well design should be robust, that is:

d) can handle variations and uncertainties in the design basis;
e) can handle changes and failures without leading to critical consequences;
f) can handle foreseeable operating conditions;

g) designed for operations throughout the wells life cycle, including permanent plug and abandonment.

The well design should be subject to a design and operational verification.

4.3.2 Design basis, premises and assumptions

A subsurface well design basis shall be prepared with objectives, premises, functional requirements and assumptions prior to commencement of planning.

The following elements should be assessed and documented in the subsurface well design basis:

a) well objective;
b) design life requirements;
c) restrictions related to drilling location (e.g. seasonal or environmental constraints);
d) well location (location data, seabed conditions);
e) target, TD criteria and tolerances;
f) offset wells;
g) geological depth prognosis with expected stratigraphy and lithology, including uncertainties;
h) temperature, pore pressure and formation stress prognosis for design life of the well, including uncertainties;
i) data acquisition;
j) identification of pressure anomalies due to depletion or nearby injector wells;
k) shallow drilling and location hazards;
l) reservoir data summary;
m) for production wells include potential for scale, wax, sand production, etc.

As an extension to the subsurface well design basis, a drilling and well design basis shall be prepared. The following should be assessed and documented:

n) drilling requirements;
o) summary of reference well data and experience;
p) wellhead and conductor design;
q) casing design;
r) cementing requirements;
s) drilling fluids;
t) well testing or completion requirements;
u) tubing design;
v) well path listing, with target requirements and proximity calculations to offset wells;
w) sidetrack options;
x) blowout contingency/relief well/capping requirements;
y) plug and abandonment solutions;
z) well studies addressing specific issues;
aa) risk analysis.

A design review shall be performed if changes occur that may cause a WBE to exceed its designed and tested operational envelope (e.g., WBE degradation, change in service loads, exposure time, etc.).

4.3.3 Well design pressure

Well design pressure (WDP) is the highest pressure expected at surface/wellhead and shall be established based on the following:

Table 5 – Well design pressure basis

Well type	Calculation basis for well design pressure
General	As a general rule, the well design pressure shall be based on reservoir pressure minus the hydrostatic pressure of gas plus kill margin, or maximum injection pressure for injection wells.
Exploration well	Use pore/reservoir pressure less the hydrostatic pressure from a column of pressurized methane gas or actual gas composition/gravity from offset wells plus kill margin.
Development well in reservoir with free gas	Use reservoir pressure less hydrostatic pressure from actual gas composition/gravity at virgin reservoir pressure plus kill margin.
Development well in reservoir without free gas	Simulations can be used to determine maximum pressure at shut-in condition based on actual reservoir fluid compositions and gas-oil-ratio plus kill margin. Beware of late life condition with depletion and possible free gas.
Gas lift, injection or stimulated well	If injection pressure is higher than the reservoir generated pressure (as described for development wells), use the maximum possible generated injection pressure from the topside system to the well, taking into consideration shutdown, PSV settings and PSV response, otherwise use the general rule.

If hydrocarbons can not be excluded in next section, the section design pressure (SDP) shall be calculated with a gas filled well based on section TD/highest pore pressure and limited to the leak-off pressure at the previous shoe. A kill margin shall be included.

Bullhead kill rates and pressures with seawater and kill fluid should be specified in a kill procedure. Unless kill margin has been specifically calculated, it is recommended to use a minimum 35 bar kill margin. Increase of the kill margin should be considered for exploration and HPHT wells.

Changes in pressures and flow capability, due to injection/production in different reservoir zones nearby or wellbore instability during the lifetime of the field, shall be accounted for in the planning.

4.3.4 Load case scenarios

Static and dynamic load case scenarios for WBEs and critical equipment installed or used in the well shall be established. Design calculations should be performed by skilled personnel, using industry recognized software. Load calculations shall be performed and compared with minimum acceptance criteria/design factors.

Anticipated well movements shall be estimated and assessed (wellhead growth).

4.3.5 Design principles

Design work shall be based on the elastic deformation principle (does not apply to material intended for deformation beyond elastic limits, e.g. expandable components).

Allowable utilization range of a pipe/tubular shall be defined as the common performance envelope area defined by intersections of:

a) the von Mises' Ellipse, and;
b) ISO/TR 10400:2007 or API TR 5C3 , 1st edition, December 2008 formulas for burst, collapse and axial stresses, and;
c) pipe end connection capacities.

The following design principles shall be used:

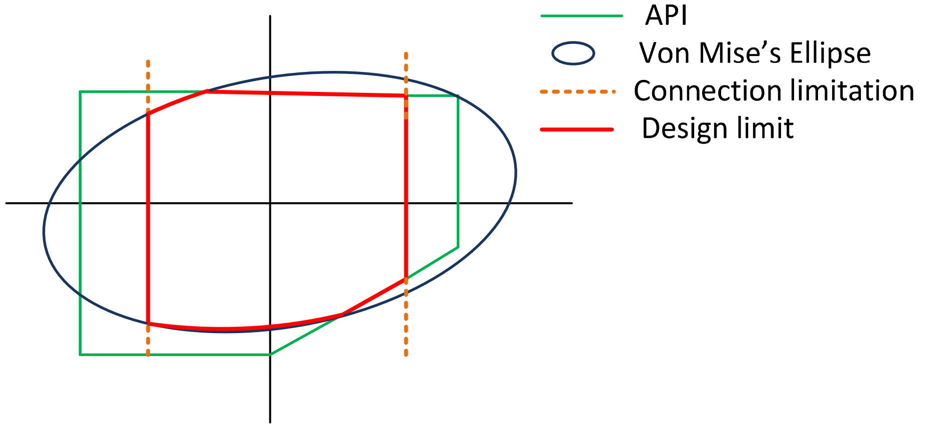


Figure 4.3.5.1 – Design principles

4.3.6 Design factors

Design factors or other equivalent acceptance criteria shall be established for:

a) burst loads;
b) collapse loads;
c) axial loads;
d) tri-axial loads.

Design factors apply to both pipe body and connections. The calculation of the design factor shall take into consideration all applicable factors influencing the materials performance, with emphasis on wall thickness manufacturing tolerance, corrosion and tubular wear over the lifecycle of the well.

The following design factors shall be used:

Table 6 – Design factors

Parameter	Design factor*	Supplementary requirement/information
Burst	1,10	
Collapse	1,10	
Axial	1,25	For well testing a design factor of 1,50 should be used to cater for pulling the packer free at the end of the test.
Tri-axial	1,25	Tri-axial design factors are not relevant for connections

*The above design factors are based on wall thickness manufacturing tolerance of minus 12,5%.

4.3.7 Structural integrity

The key components (conductor, guide base, risers) that provide structural integrity of the well during its service life shall be evaluated with respect to loads, wear and corrosion.

4.4 Risk assessment and risk verification methods

An assessment of well integrity risks associated with the intended operation shall be performed. The risk of a well integrity failure or well control incident shall be assessed. When evaluating well integrity risk, the failure modes of primary WBEs and the availability of secondary well barrier shall be considered. If a well barrier is degraded, a risk assessment should be performed considering the following:

a) cause of degradation;
b) potential of escalation;
c) reliability and failure modes of primary WBEs;

d) availability and reliability of secondary WBEs;
e) outline plan to restore or replace degraded well barrier (technical and time line).

Onsite safe job analysis should be conducted for:

f) new or non-standard operations;
g) operations involving use of new technology or modified equipment;
h) hazardous operations;
i) change in actual conditions which may increase the risk.

See NORSOK Z-013, Risk and emergency preparedness assessment.

4.5 Simultaneous and critical activities

Simultaneous and critical activities and operations that may cause loss of or severe degradation to a well barrier shall be thoroughly planned, analysed and performed with the objective of limiting additional risk imposed by multiple activities and operations. These can be lifting of heavy objects above wells, construction activities, drilling close to existing wells, inhibition of alarms or temporary shut-down of power/control system for operating WBEs. Acceptance of simultaneous and critical activities and operations shall be in accordance with defined acceptance criteria and shall be quality assured through risk assessments.

Procedures for the control of simultaneous and critical activities and operations, with information to relevant personnel, shall be in place prior to commencement.

4.6 Activity and operation shut-down criteria

Criteria for shut-down of the activities or operations shall be established.

Normal activities and operations should cease, when:

a) having a weakened/impaired well barrier/well barrier element or failure/loss of a well barrier/well barrier element;
b) there is a high probability for exceeding allowable operating limits of well control equipment and other critical equipment;
c) H_2S/CO_2 content of fluids or gases exceeds personnel exposure limits, operating limits of the well control equipment and other critical equipment.

4.7 Activity programs and procedures

4.7.1 Preparation of activity program

An activity program shall be issued prior to commencement of:

a) drilling activities;
b) well testing activities;
c) completion activities;
d) well intervention activities;
e) pumping activities;
f) re-completion or workover activities;
g) suspension and abandonment activities.

The main contractor(s) should be involved in the process of developing the activity program.

The program may be supplemented by more detailed procedures relating to planning, execution and close-out of the activities.

All significant deviations from the program or procedures shall be formally documented, approved and distributed to the users of the program or procedure.

Program, procedures and plans that have a validity period for more than one (1) year should be regularly reviewed and updated.

A new plan shall be prepared for wells that have not been put to use according to the original plan, or that have been temporarily abandoned – without monitoring for more than three years.

4.7.2 Management of change

A Management of Change (MoC) procedure covering the life cycle of the well shall be implemented.

The procedure should describe the processes used to assess risk, mitigate, authorize, and document technical, operational or organizational changes to previously approved information or procedures.

A MoC process should cover changes to:

a) surface and well control equipment;
b) impact on WBEs;
c) well type (e.g. conversion from producer to injector);
d) procedures;
e) rig or contractor well control equipment;
f) key personnel;
h) any change in design basis or operating condition for the well.

A proposed change shall be supported by a documented approval of the following:

i) reason for change;
j) description of the new proposed solution;
k) possible consequences and uncertainties;
l) updated risk assessment in line with the proposed change.

All appropriate and applicable disciplines shall be involved in the preparation of the proposed solution and/or endorse the proposal.

Changes to programs and procedures shall be approved at the level of the original approval, or at a level proportionate with the assessed risk of the change, and include input of those affected by the change.

4.7.3 Maintenance program and procedures

A preventive maintenance program shall be prepared for all WBEs that are not continuously monitored or pressure trended (e.g. XT valves and instrumentation valves which are part of the well barrier).

All periodical inspections, pressure and function tests shall be a part of the maintenance program. Further reference is given to number F. Monitoring in the EAC tables in section 15.

The test and inspection intervals shall be defined and be based on reliability data of the WBEs as well as field and well specific conditions that may influence the reliability over time.

Procedures for periodic testing and inspections shall be prepared. The procedures shall describe any preparations and how the test practically shall be carried out. Valve positions, test medium, pressures and acceptance criteria shall be clearly stated.

4.8 Blowout contingency plans

4.8.1 Installation/field blowout contingency plan

A blowout contingency plan covering drilling, well, production and injection activities shall be established for each installation, field or area.

The blowout contingency plan shall as a minimum address the following:

a) field layout;
b) well design;
c) primary kill strategy in a blowout case;
d) a description of, or reference to, the emergency response organization (Drilling and Well, Search and Rescue, Oil Spill, etc.).

A blowout and kill rate simulation study shall be performed for the well design expected to give the highest blowout and kill rates in the field and for every exploration well.

The following blowout scenarios should be covered for penetrated reservoirs:

e) through open hole/casing;

f) through drillpipe or tubing;
g) through drillpipe/casing or casing/casing annulus;
h) for subsea wells: release to seabed. The likelihood of release to surface through the riser should be considered.

The following data should be used for blowout and kill simulations:

i) expected values for reservoir parameters (pore pressure, permeability, porosity, net-gross pay, etc.);
j) expected top of reservoir depth;
k) expected productivity index / transient productivity index;
l) expected fluid type parameters, if oil is expected, but gas cannot be disregarded both cases shall be simulated;
m) mechanical skin is zero;
n) no restrictions in the flow path;
o) planned well design (hole size, casing setting depth, etc.).

For offshore wells, the well design should enable killing a blowout with one (1) relief well. If two (2) relief wells are required, it shall be documented that such an operation is feasible with respect to logistics, weather criteria and availability of rigs. The feasibility should be supported by a risk assessment demonstrating that the proposed solution involving more than one relief well is achievable. An offshore well design that requires more than two (2) relief wells is not acceptable.

4.8.2 Plan for drilling a relief well

An outline plan for drilling relief well(s) shall cover each well, field or installation. For subsea templates and platforms it shall be demonstrated that it is possible to reach the most challenging well from each relief well location. The plan shall contain:

a) minimum two (2) suitable rig locations including anchoring assessment (only applicable for anchored rigs) for the two relief locations. If blowout and kill simulations show the need for two relief wells, minimum three relief well locations shall be in place;
b) the relief well locations should be up-wind and up-current of the well location based on prevailing wind and current data;
c) shallow gas assessment for the relief well locations;
d) simplified relief well paths from the relief well locations to the intersection point in the blowing well;
e) overview of suitable rig(s)/vessels for relief well drilling/operations based on the necessary capacities (well specific conditions, water depth, pump rate/pump pressure/mud storage volume, etc.),and or necessary equipment modifications to achieve required capacity;
f) description of primary killing method. In most cases this will be a high rate dynamic kill operation through the relief well which directly intersects the blowing well;
g) updates reflecting the current field conditions and pressures in the well and reservoir.

The time for mobilizing relief well rig(s) shall be evaluated in the planning phase. Initiation of relief well drilling should start no later than twelve (12) days after the decision to drill the relief well(s) has been taken.

4.8.3 Plan for capping and containment of a blowing subsea well

An outline plan for capping and containment in a blowing subsea well should be in place to demonstrate mobilization and installation of capping equipment within a reasonable timeframe. The plan should:

a) evaluate the feasibility of capping a blowout scenario at the given water depth;
b) identify all connections and possible interfaces from wellhead to flexible joint;
c) identify all connections and possible interfaces from XT to interface to workover equipment;
d) include an overview of equipment requirements and availability to allow installation of a capping stack, including an adapter to enable connection of the capping stack;
e) consider additional well load cases resulting from a capping operation.

4.9 Personnel competence and supervision

4.9.1 Personnel competence

Competence requirements for personnel working with well integrity shall be described. Verification of the individual's competence can be done through gap analysis, tests or interviews. A training program, which may consist of courses, e-learning, self-study program or on-the-job training, should be conducted to close gaps.

The position competence curriculum should address the following subjects:

a) roles and responsibilities for well integrity management within the company, covering well construction and operational phases;
b) wellbore physics (formation integrity, dynamic pressure and temperature regimes);
c) well construction principles, casing design, completion design and definition of load cases;
d) preparation of well handover documentation;
e) establishment of a two well barrier principle for the well construction and operational phases with preparation of WBSs;
f) operational supervision, frequent testing, monitoring, maintenance, inspection, troubleshooting, diagnostics, annulus pressure management and trend monitoring.

Onsite drilling and well supervisory personnel shall hold a valid well control certificate issued by an international recognized party (i.e. IWCF or IADC). When new equipment or techniques will be used, involved personnel shall attend theoretical and practical proficiency training.

All training shall be documented.

4.9.2 Supervision of operations

The well site activities and operations shall be monitored and supervised by a competent person who shall ensure that procedures, programs, plans and routines are followed in a safe and efficient manner.

Roles, responsibilities and authorities for personnel and positions that are overall responsible for well integrity through the various phases of the well, shall be defined.

4.10 Experience transfer and reporting

4.10.1 Experience transfer

The results of, and the experience from well activities and operations shall be collected, documented and made available for future use and continuous improvement.

The experience transfer and reporting system should comprise of:

a) drilling and well activities reporting system;
b) accident and incident reporting system;
c) non-conformity/deviations/management of change;
d) end of well/activity/operations reports;
e) risk register for monitoring of risks;
f) special reports addressing particular events or issues on the well.

4.10.2 Well integrity records

Information relating to well integrity shall be documented. The following records should be retained:

Table 7 – Well integrity records

Item	Description	Retention period	Comments
1.	Equipment specifications and material certificates of technical components of well barriers/WBEs	For the period that it is in use	Dimensional size and type of material for wellhead, casing, liner, tubing, packers, etc.
2.	Directional survey and wellhead coordinates	Unlimited	For future anti-collision awareness and relief well contingency
3.	Pressure test records and other records relating to acceptance of well barriers or WBEs	Until the well has been permanently abandoned. Temporary WBEs (e.g. intervention) for the period that it is in use	Can be used for statistical purposes
4.	Annuli pressure records	Until the well has been permanently abandoned	Can be used for reference purposes
5.	Casing and tubing load case calculations	Until the well has been permanently abandoned	Documenting scenarios and actual safety factors
6.	As built WBSs	Until the well has been permanently abandoned	Showing actual status at all times
7.	Well integrity tests and logs	Until the well has been permanently abandoned	Applies to cement/formation WBEs and tubing/casing wear
8.	Well handover document	Until the well has been permanently abandoned	This should describe the well barrier status before the responsibility for well integrity is transferred to another organizational unit. (See section 8)
9.	Drills conducted and results	1 year	Can be used for statistical purposes
10.	Inspection and preventive and corrective maintenance records	Until the well has been permanently abandoned	Can be used for reference purposes
11.	Documentation related to how wells are permanently abandoned	Unlimited	Should include well barrier description, logs and test charts of tested elements

4.10.3 Well integrity management

A systematic approach shall be established to manage the well integrity in all stages of the life cycle of the well, from construction phase to final abandonment. The system should consist of the following elements.

1. Organization:
   a) roles and responsibilities;
   b) competency requirements;
   c) strategy and objectives;
   d) emergency preparedness.
2. Design:
   a) use of standards;
   b) establishing well barrier;

   c) equipment requirements;
   d) safety systems;
   e) qualification.

3. Operational procedures:
   a) operating limits and constraints;
   b) monitoring;
   c) transfer of information.

4. Data system:
   a) collection;
   b) storage;
   c) monitoring.

5. Analysis:
   a) trend monitoring;
   b) assessment of performance;
   c) risk status;
   d) continuous improvement.

See Norwegian Oil and Gas Association recommended guideline for Well Integrity, Guideline no. 117 for more detailed information.

5 Drilling activities

5.1 General

This section covers requirements and guidelines pertaining to well integrity during drilling activities.

The activity starts with spudding of the well and concludes with preparation for completion, testing or abandonment activities.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

5.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (5.8).

5.3 Well barrier acceptance criteria

The following list defines specific requirements and guidelines for well barriers:

a) Drilling of top hole for conductor and surface casing can be conducted with the fluid column as the only well barrier.
b) The surface casing shall be installed before drilling into an abnormal pressured zone.
c) Prior to drilling out of the surface casing, a drilling BOP shall be installed.
d) Floating (partially filled up) of non-shearable tubular strings in open hole or with open perforations exposed should be conducted with two qualified WBEs located inside the tubular. The inside WBEs shall be designed such that fluid can be circulated.

5.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 8 – Additional EAC requirements

<table>
<tr><th>Table no.</th><th>Element name</th><th>Additional features, requirements and guidelines</th></tr>
<tr><td>1</td><td>Fluid column</td><td>
Marine riser disconnect:
The fluid column is not a qualified well barrier when the marine riser has been disconnected. Planned or accidental disconnect of the marine riser, resulting in loss of the fluid well barrier shall be accounted for. Procedures for planning and implementation of compensating measures shall be established.
If the uncased borehole has penetrated hydrocarbon bearing formations or abnormally pressured formations with a flow potential and the hydrostatic pressure in the well with the riser disconnected may become less than or equal to the pore/reservoir pressure of these formations, risk reducing measures shall be established with the following priority:
A. reduce the probability of having an influx during the disconnect period
B. strengthen the availability/reliability of the remaining well barrier.
The following risk reducing measures should be applied:
<table>
<tr><th>Priority</th><th>Risk reducing measures</th><th>Comments</th></tr>
<tr><td>A</td><td>Drill with “Riser Margin”</td><td>Maintain a drilling fluid density that will provide an overbalance with the marine riser disconnected.
This alternative shall be assessed as the primary compensating measure.</td></tr>
<tr><td>A</td><td>Spot a weighted fluid</td><td>Displace the entire well or part of the well to a fluid with a density that will provide an overbalance towards zones with a flow potential with the marine riser disconnected.</td></tr>
<tr><td>B</td><td>Install a bridge plug</td><td>Install a bridge plug with storm valve below the wellhead.</td></tr>
<tr><td>B</td><td>Two shear-/seal rams</td><td>Use two shear/seal rams in the drilling BOP as an extra seal element during hang-off / drive-off situations.</td></tr>
</table>
</td></tr>
</table>

5.5 Well control action procedures and drills

5.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 9 – Well control action procedures

Item	Description	Comments
1.	Shallow gas influx	
2.	Influx occurring with shearable pipe or tools through the BOP	Include plan to centralize pipe before shear
3.	Influx occurring with non-shearable pipe or tools through the BOP	
4.	Influx occurring with no pipe or tools through the BOP	
5.	Influx containing H_2S	
6.	Influx from any of the previously drilled lateral wellbores	Drilling the lateral bore in a multi-lateral well

5.5.2 Well control action drills

The following well control action drills should be performed:

Table 10 – Well control action drills

Type	Frequency	Objective	Comments
Shallow gas kick drill - drilling	Once per well with crew on tour	Response training to a shallow gas influx	To be done prior to drilling surface hole or pilot hole
Kick drill - drilling	Once per week per crew	Response training to an influx while drilling (bit on bottom)	
Kick drill - tripping	Once per week per crew	Response training to an influx while tripping (bit off bottom). Practice centralizing to prepare for shearing pipe.	
Choke drill	Once per well with crew on tour	Practice in operating the remotely operated choke with pressure in the well	Before drilling out of the last casing set above a prospective reservoir Include the scenario of flowing well with gas on drill floor as a table top exercise
H_2S drill	Prior to drilling into a potential H_2S zone/reservoir	Practice in use of respiratory equipment	
Subsea BOP: BOP on deck drill	Every time BOP is on deck	Operate BOP panels	Include the latter steps of the choke drill with handling of emergency situation with gas on drill floor. For dynamically positioned rigs the scenario should include communication from the bridge to drill floor and operate the emergency disconnect sequence
Subsea BOP: Diverter drill/gas in riser drill	Every time BOP is landed, before the seawater is displaced from the riser system	Line up diverter	Include the scenario of gas in the riser above the BOP and line up of the diverter to overboard lines. This drill can use seawater to flow through overboard lines

5.6 Casing design

5.6.1 General

Casing, liner and tieback-strings shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations.

The design process shall cover the complete well or section lifespan encompassing all stages from installation to permanent abandonment and include effects of goods deterioration.

Design basis and margins shall be known and documented.

Weak-points shall be identified and documented.

All casing strings that are part of a well barrier in subsequent phases shall be logged for wear after drilling if simulation shows wear exceeding maximum allowed wear, based on casing design.

For drilling and completion operations conducted through-tubing where all or parts of the completion string will serve as a WBE, the tubing with all relevant accessories shall be reclassified to production casing and re-qualified to relevant load cases. All primary and secondary WBEs shall be verified to comply with the new design loads prior to commencing operation.

5.6.2 Design basis, premises and assumptions

As a minimum the following should be addressed in the design process:

a) planned well trajectory and bending stresses induced by doglegs and hole curvature;
b) maximum allowable setting depth with regards to kick margin;
c) estimated pore pressure development;
d) estimated formation integrity development;
e) estimated temperature gradient and temperature related effects;
f) drilling fluids and cement program;
g) loads induced by well services and operations;
h) completion design requirements;
i) estimated casing wear;
j) setting depth restrictions due to formation evaluation requirements;
k) potential for H_2S, CO_2;
l) metallurgical considerations;
m) well abandonment requirements;
n) ECD and surge/swab effects due to narrow annulus clearances;
o) isolation of weak formation, potential loss zones, sloughing and caving formations and protection of reservoirs;
p) geo-tectonic forces;
q) relief well feasibility;
r) experience from previous wells in the area or similar wells.

5.6.3 Load cases

When designing for burst, collapse and axial loads, the following load cases shall be considered. This list is not comprehensive and load cases applicable for the planned activity shall be applied. Possible changes in design loads and stresses during the life expectancy of the well shall be assessed.

Table 11 – Load cases

Item	Description	Comments
1.	Gas kick	Size/volume and intensity to be defined
2.	Gas filled casing	Applicable to last casing above the reservoir and subsequent casings
3.	Production and/or Injection tubing leaks	Based on WDP. See 7.7.2 for multipurpose wells
4.	Cementing of casing	
5.	Leak testing casing	See 7.7.2 for multipurpose wells
6.	Thermal expansion of fluid in enclosed annuli	Collapse and burst
7.	Dynamic loads from running of casing, including over pull to free stuck casing	
8.	Permanent abandonment	See section 9.3.2

5.6.4 Design factors

Casing shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The design factors shall be as described in section 4.3.6.

5.6.5 Conductor design

The conductor shall be designed to give adequate structural support to the wellhead and all tubulars/equipment (e.g. XT, BOP's, well capping equipment) installed during the expected lifespan of the well. An analysis shall be performed to confirm the ability to withstand any loads the conductor may be exposed to.

The conductor analysis should as a minimum address the following:

a) extreme weather conditions;
b) vortex induced vibrations;
c) fatigue;
d) corrosion;
e) marine growth.

5.7 Other topics

5.7.1 Drilling location

A site survey shall be performed and interpreted to identify water depth, seabed and sub-surface hazards at the intended well location and relief well locations. The survey should be performed with means of sonar equipment and direct visual observations. Sea bed topography, anchor holding capabilities, presence of boulders, cables, pipelines and other obstructions should be assessed.

Well locations shall be selected where the risk associated with shallow gas is acceptable.

The seismic lines shall have a penetration covering the geological sequence to the setting depth for the surface casing.

Soil tests should be available for deep water and jack-up drilling locations.

5.7.2 Shallow gas

The risk of drilling into shallow gas zone(s) shall be assessed for all wells. Risk reducing measures shall be applied.

The following shall be established:

a) a model/procedure for defining the risk of shallow gas and operational constraints;
b) criteria for drilling a pilot hole and when to drill with riser/diverter/mud recovery system installed;
c) operational procedures and well control action procedures for drilling through potential shallow gas zones with focus on risk reducing measures;
d) alternative drilling locations.

5.7.2.1 Shallow gas risk assessment model

The well shall be classified as a potential shallow gas well if any of the following applies:

a) No relevant offset well exists.
b) Shallow gas is detected in relevant offset wells and in the same formations that will be penetrated in the well.
c) A structural closure is seen on the seismic that could trap shallow gas.
d) There are anomalies on the seismic interpretation that could indicate presence of gas.

The consequence of drilling through shallow gas zones should be evaluated with regards to:

e) type of drilling rig;
f) water depth;
g) drilling with or without riser or other method of pumped mud recovery;
h) casing strings and cementation;
i) wind and current conditions.

5.7.2.2 Operational constraints

The following operational constraints are applicable for a potential shallow gas well:

a) The well location shall if possible be moved if consequence and/or probability of shallow gas is high.
b) A pilot hole with a diameter that allows the well to be killed dynamically shall be drilled through all potential shallow gas zones.
c) Predicted shallow gas zones with abnormal pressure shall be drilled with a pilot hole of maximum 12 1/4" hole size and weighted drilling fluid.
d) Flow checks in the pilot hole shall last for a minimum of 30 min.
e) A non-ported float should be installed in the BHA.
f) The potential shallow gas zones should be logged with LWD gamma ray and resistivity.
g) For subsea wells, returns from the borehole shall be observed continuously with ROV camera or remote camera.
h) Kill fluid shall be available until the pilot hole has been opened.
i) Cementing materials shall be on location to establish a minimum 50 m long gas tight cement plug in the pilot hole plus 200 % excess.
j) Plans and materials for setting surface casing above a shallow gas zone should be in place.

For subsea wells where there is no potential for shallow gas and a pilot hole is not drilled, a drilling facility impact assessment shall be performed with respect to shallow gas influx in cases where the water depth is less than 100 m.

5.7.3 Pore and formation integrity pressure estimation

Estimation of pore pressure, collapse pressure and formation integrity pressure shall be prepared and should be updated as new formation is drilled.

The methods and techniques for estimating the pore pressure shall be described. The risk of a change in pore pressure compared to the original pore pressure due to injection of water, gas, cuttings and slop in other wells shall be assessed.

5.7.4 Well trajectory

Precise determination of the well path is important to:

a) avoid penetrating another well,
b) facilitate intersection of the wellbore with a relief well (blowout),
c) facilitate geological modelling,
d) facilitate anti-collision assessments for new wells.

5.7.4.1 Well trajectory measurements

The surface location coordinates of the wellbore centre shall be determined with use of differential global positioning system. Well slot co-ordinates can be established by measurements from a known reference point (fixed point on a platform, subsea template, etc.).

During drilling of new formation, measurement of wellbore inclination and direction shall be obtained at least every 100 m MD. All survey plots should be referenced to grid north.

The position of the wellbore being drilled (reference well) and the distance to adjacent wells shall be known at all times. The minimum angle of curvature method or other equivalent models should be used.

A survey program should be established to minimize ellipses of uncertainty.

Procedures for quality control of survey data shall be in place. The ellipses of uncertainty shall be based on survey tool error models which reflect the level of quality control applied.

5.7.4.2 Model and acceptance criteria for separation between wellbores

A model for quantifying the uncertainty shall be established. The probability for the wellbore to be within the calculated uncertainty ellipses should exceed 95 %.

Minimum acceptable separation distance between wellbores and risk reducing actions shall be defined.

The table below describes recommended actions if the model indicates that the separation between wellbores is less than the minimum acceptable separation.

Table 12 – Wellbore separation distance and actions

Point of potential contact	Recommended action
Casing with no WBE function	The cuttings from the reference well should be analysed to determine cement and/or metal content prior to the separation between wellbores becoming less than the minimum acceptable separation and when drilling within this range. The annuli in adjacent well(s) with access to the point of potential contact should be pressurised and monitored for changes in pressure to detect penetration by the drill bit. If this is not possible, alternative methods such as noise detection should be used.
Casing with a well barrier element function or production liner	As above, and: The production/injection of the adjacent well(s) should cease, and the adjacent well(s) should be secured by closing of the DHSV/ASV, or setting tubing plugs, bridge plugs, or cement plugs. Installation of a well barrier below the estimated point of contact shall be assessed.

5.7.5 Through tubing drilling activities

Through tubing drilling activities shall be regarded as alterations to an existing well and hence a new design basis shall be established. A new well design process shall be carried out on the revised design basis/premises.

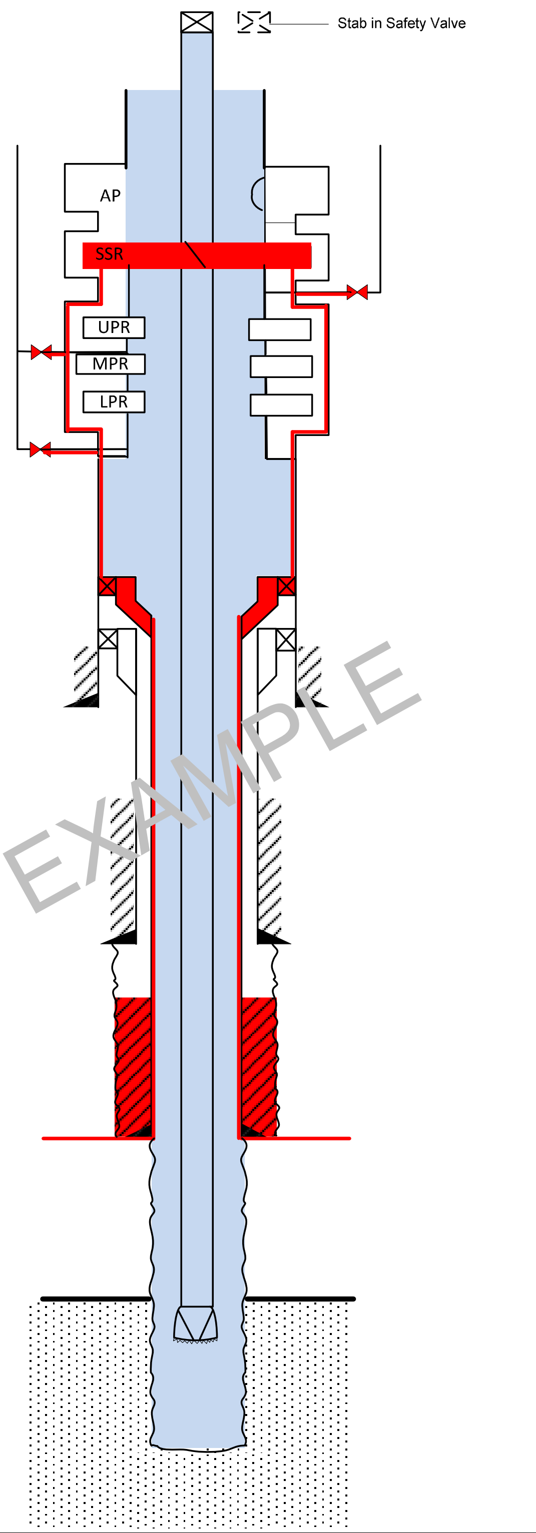
All primary and secondary WBEs shall be verified to meet the new design loads prior to commencing operation.

Well barrier elements that are exposed to drilling loads (production tree, tubing, DHSV, etc.) should either be protected against the loads (e.g. by installing wear sleeve/bushing in DHSV and/or production tree) or be verified capable of resisting the defined loads. Calculations documenting acceptance of the new loads and/or mitigations to reduce/eliminate loads should be verified by supplier and if critical, by an independent third party.

If through-tubing drilling is performed in coiled tubing/snubbing/under balanced or managed pressure mode, the relevant sections (section 11, section 12 and section 13) describing these operations shall be adhered to.

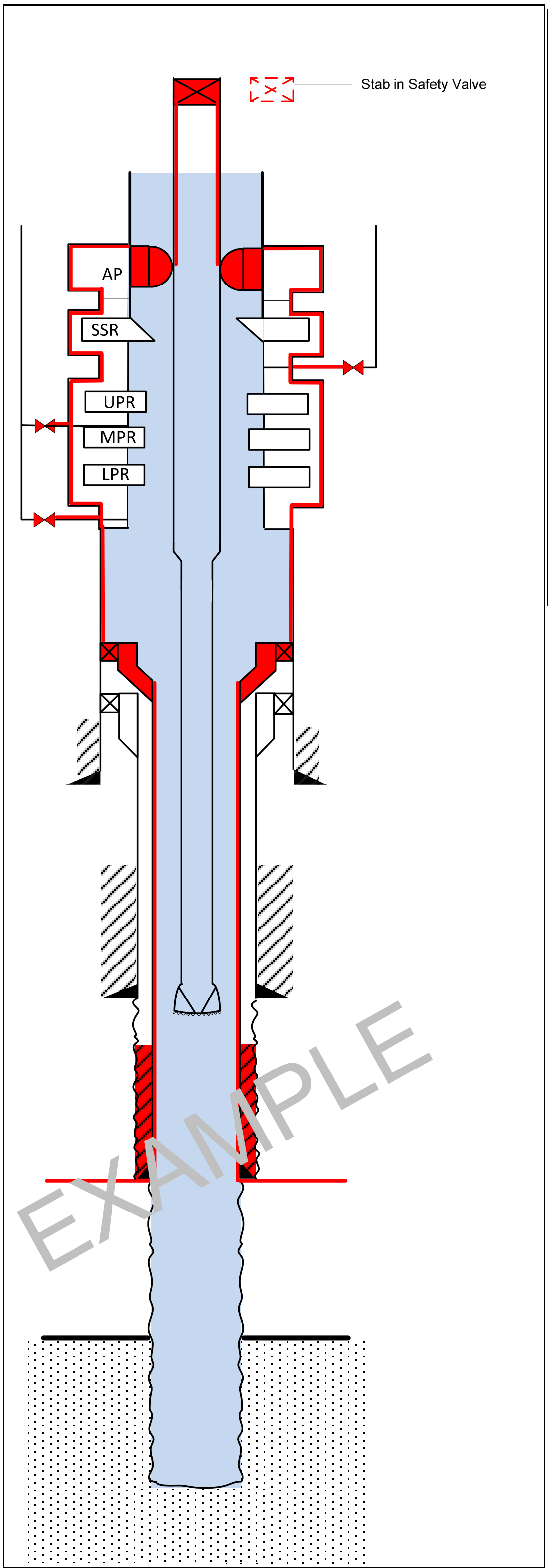
5.8 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



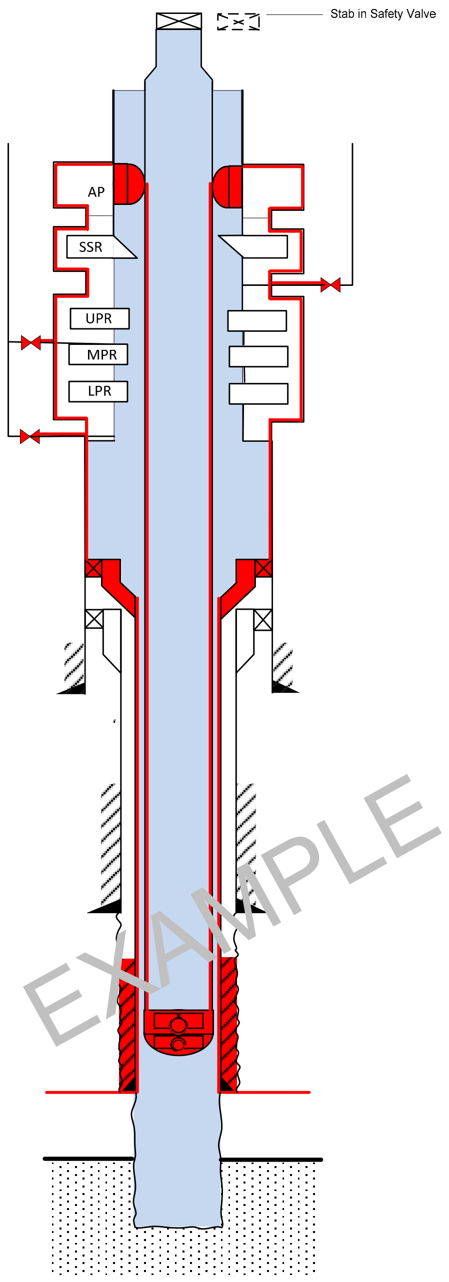
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser	26	
Drilling BOP	4	

Figure 5.8.1 – Drilling, coring and tripping with shearable string



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser (J/P)	26	
Drilling BOP	4	
Drill string	3	
Stab-in safety valve	40	

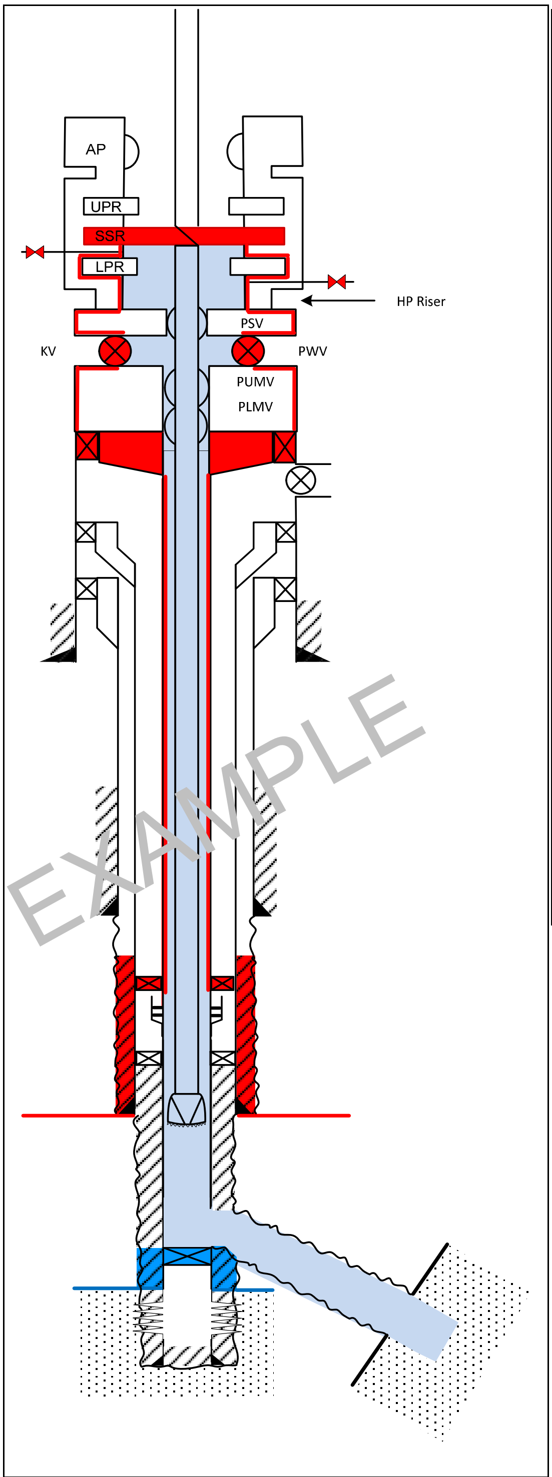
Figure 5.8.2 – Running non-shearable drill string



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser (J/P)	26	
Drilling BOP	4	
Casing	2	
Casing float valves	41	

Note: Stab-in safety valve is readily available on the drill floor.

Figure 5.8.3 – Running non-shearable casing



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier (sidetrack)		
Fluid column	1	
Primary well barrier (original hole)		
In-situ formation	51	
Casing cement	22	
Casing	2	
Mechanical tubular plug	28	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production packer	7	
Completion string	25	
Wellhead	5	
Tubing hanger	10	
Surface tree	33	
High pressure riser	26	
Drilling BOP	4	

Figure 5.8.4 – Through-tubing drilling and coring

6 Well testing activities

6.1 General

This section covers requirements and guidelines pertaining to well integrity during well testing in exploration and appraisal wells. The activity starts after having drilled and logged the last open hole section. The activity concludes when the well has been killed and the test string has been recovered.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

6.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (6.8).

6.3 Well barrier acceptance criteria

The following list defines specific requirements and guidelines for well barriers:

a) It shall be possible to close the test string at the BOP level. For subsea operations it shall also be possible to disconnect the test string below the blind/shear rams.
b) It shall be possible to shear the landing string/tubing and seal the wellbore.
c) It shall be possible to kill the well by circulating kill fluid via the STT using the fluid pump or high pressure (cement) pump, with returns through the rig's choke manifold and fluid or gas separator.
d) It shall be possible to establish a circulation path, via the test string at all times.

6.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 13 – Additional EAC requirements

Table no.	Element name	Additional features, requirements and guidelines
1	Fluid column	When annular fluids with kill weight density are used, a minimum of 50 % additional well volume of the same or alternative fluid shall be available on site. The trip tank level shall be monitored continuously.
4	Drilling BOP	It shall have sufficient height and ram configuration to accommodate a SSTT (or safety valve for jack-ups) whilst allowing closure of two rams (middle pipe ram is used with lower pipe ram as back-up) around the slick joint. There shall be choke and kill outlets below the middle pipe ram. It may be necessary to utilise an annular as the second ram on jack-up rigs where the configuration does not permit closure of two pipe rams. Ported slick joints would be required in this case. It shall have the ability to close the shear/seal ram above the SSTT in a connected configuration (with latch attached to valve). BOP elastomers which may contact the well test string (slick joint) shall have a documented ability to withstand the maximum temperature for the duration of the well test.
22	Casing / liner cement	When planning to set the well test packer inside a liner it shall be verified by pressure testing that the liner lap has sufficient pressure retaining capacity to withstand the maximum pressure that may be applied during well test operations.
43	Liner top packer	

6.5 Well control action procedures and drills

6.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 14 – Well control action procedures

Item	Description	Comments
1.	Inflow or fluid loss while running or pulling test string	A stab-in (tubing) safety valve made up to the necessary x-over(s) to the string shall be prepared and made ready for use at all times.
2.	Tubing leak	Decision tree showing required actions in relation to leak location shall be prepared and reviewed at the well site prior to commencement of well test operations.
3.	Disconnect SSTT	Criteria for maximum heave, riser angle and pitch/roll should be described. The time from activating valve closure until latch assembly is released should be documented and used in the unlatching procedure. It should be possible to raise the latch assembly above the LMRP disconnect point without having to break connections at the rig floor. For dynamic positioned vessels, operating criteria shall be described for drift / drive-off situations, with defined actions.
4.	Presence of H_2S	Criteria for when to implement contingency measures or abort the test should be established.
5.	Killing the well	Planned and contingency kill methods should be documented.
6.	Stuck string	Maximum allowable overpull should be documented.

Tool pusher or driller and drill stem test tool or SSTT operator shall be on rig floor at all times, during the well test phase.

6.5.2 Well control drills

The following well control action drills should be performed:

Table 15 – Well control drills

Type	Frequency	Objective	Comments
Disconnect of the SSTT	Once per crew as soon as practical after rig-up.	Response training.	Without physically disconnecting the SSTT (working through all the steps required for planned and emergency disconnect).
Major leak above the seabed	Once per crew as soon as practical after rig-up.	Response training.	Following decision tree's included in well program

6.6 Well test design

6.6.1 General

The selection of well testing operational methods, procedures and equipment shall be determined by considerations of safety and risk to the environment, operational efficiency and cost effectiveness. The well test operations procedure shall define and specify limitations and well barriers.

6.6.2 Design basis, premises and assumptions

See NORSOK D-SR-007.

The well design pressure shall be determined and should consider:

a) maximum pore pressure;
b) maximum pressure to fire TCP guns;
c) maximum bullhead pressure (shut-in tubing pressure +70 bar).

Material selection for downhole and surface equipment shall account for the potential of H_2S.

6.6.3 Load cases

All components of the test string shall be subject to load case verification. Axial and tri-axial loads shall be calculated and checked against tubing and test string component strength. The weakest point in the test string shall be clearly identified with regards to burst, collapse and tensile rating.

The following load cases shall be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed:

Table 16 – Load cases

Item	Description	Comments
1.	Test string collapse at depth; shut-in wellhead pressure above annulus fluid hydrostatic (tubing leak below wellhead)	Apply highest case annulus pressure on top of annulus fluid column (applied pressure or tubing leak). Assume lightest fluid gradient inside tubing (dry gas if applicable).
2.	Casing / liner collapse below packer where test string is evacuated	
3.	Burst at surface (below wellhead) when pressure testing string	Apply maximum test or bullheading pressure with weight of string below wellhead for the tubing side and zero pressure on the annulus side.
4.	Pulling load at surface when attempting to release a stuck test string	Apply necessary pull for parting string at weak point plus 20 % with string weight not corrected for buoyancy.
5.	Tubing movement	Pressure testing, production, shut-in and killing with cold fluid. Apply maximum bullheading pressure at cold temperature on the tubing side with zero annulus pressure.

6.6.4 Minimum design factors

Well string/components shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The minimum design factors shall be as described in section 4.3.6.

6.7 Other topics

6.7.1 Process and emergency shut-down system

An emergency shut-down and disconnect plan shall be established and be reviewed by all involved parties. The plan shall include automatic and manual actions and contingency procedures.

6.7.2 Hydrate prevention

Chemical injection shall be available at critical points in the test string and at surface. Actions for preventing and removing hydrates should be included in the procedures. Annulus fluid selection should consider the risk of hydrate formation in the case of a tubing leak or discharge of hydrocarbons into the marine riser when disconnected from the SSTT.

6.7.3 Well testing with underbalanced annulus fluid

An inflow test of the production liner, liner lap and shoe shall be conducted prior to displacing the overbalanced well fluid with underbalanced well fluid. The following apply:

a) The inflow test value should include a safety margin, which can be achieved by utilising fluids lighter than the packer fluid during the inflow test.
b) The inflow test acceptance criteria should account for thermal effects.
c) The production casing shall be pressure tested to well design pressure using the packer fluid.
d) The well test packer shall be pressure tested from below to maximum differential pressure +10 %.
e) Kill fluid shall be readily available in tanks for displacement of the entire well volume +50 %.

6.7.4 Deep water well testing

The increased risk of process problems (hydrates, wax, and asphaltines) due to the cooling effect in deep water should be evaluated. Annulus fluid selection should consider the thermal conductivity of fluid's and their ability to maximise flowing temperature at wellhead depth.

The SSTT temperature should be monitored during testing.

6.7.5 On-site pre-test meeting

A pre-test meeting shall be conducted with all involved personnel, addressing the following items:

a) outline well test design;
b) expected pressure, temperature and flow rates;
c) expected duration of operations;
d) contingency reactions;
e) risk analysis results;
f) well test PSD system description and function;
g) rig ESD system description;
h) explanation of organization and responsibilities;
i) enforcing of special safety restrictions (smoking, welding, grinding, use of open flame and areas with no access);
j) locations of manual PSD and ESD buttons;
k) locations of fire fighting equipment;
l) pollution and oil spill actions.

6.7.6 Disconnecting the subsea test tree

When testing on floating vessels, procedures and plans pertaining to disconnect (planned and emergency) of the SSTT and drilling riser shall be reviewed by all involved parties.

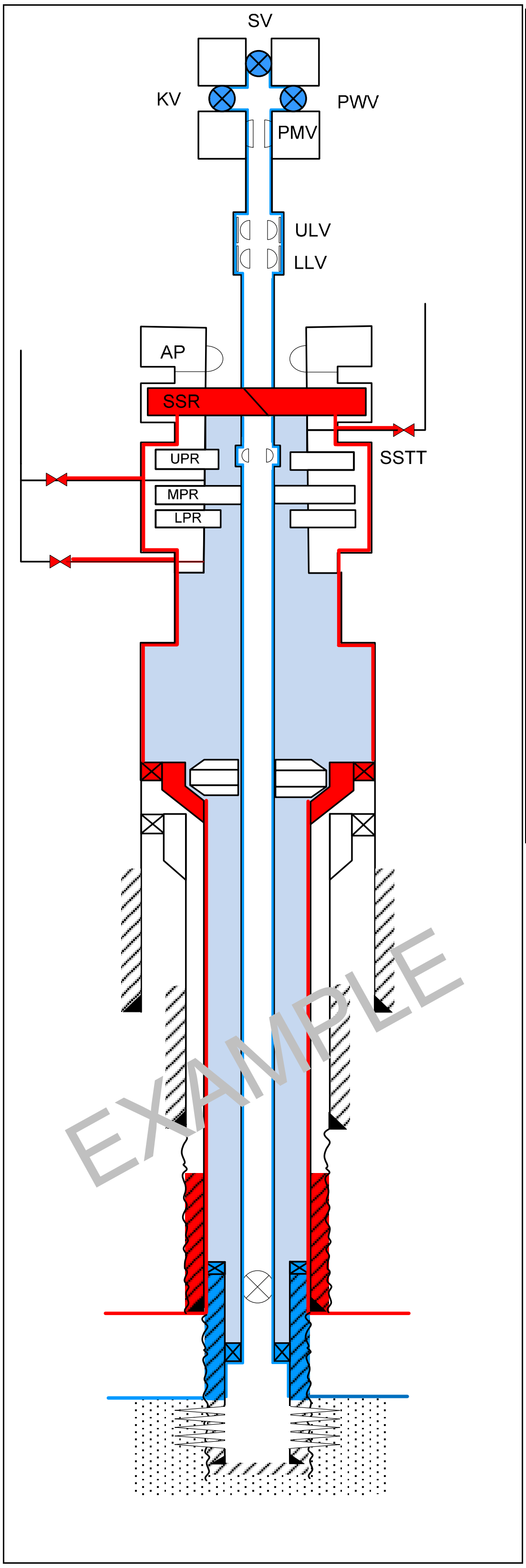
If the test string needs to be disconnected and time permits (planned), one of the following methods should be applied:

a) close the downhole tester valve, open the circulating valve and circulate kill fluid into the string. (Overbalanced annulus cases only); or
b) bullhead the string or landing string content into the formation; or
c) close the downhole tester valve and SSTT. Inflow test the SSTT prior to disconnect.

If time does not permit, an emergency disconnect should be initiated. Emergency disconnect procedures shall be documented and reviewed by all involved parties.
The risk of environmental spills during a disconnect of the marine riser should be assessed. Consideration should be given to the use of a retainer valve above the SSTT.

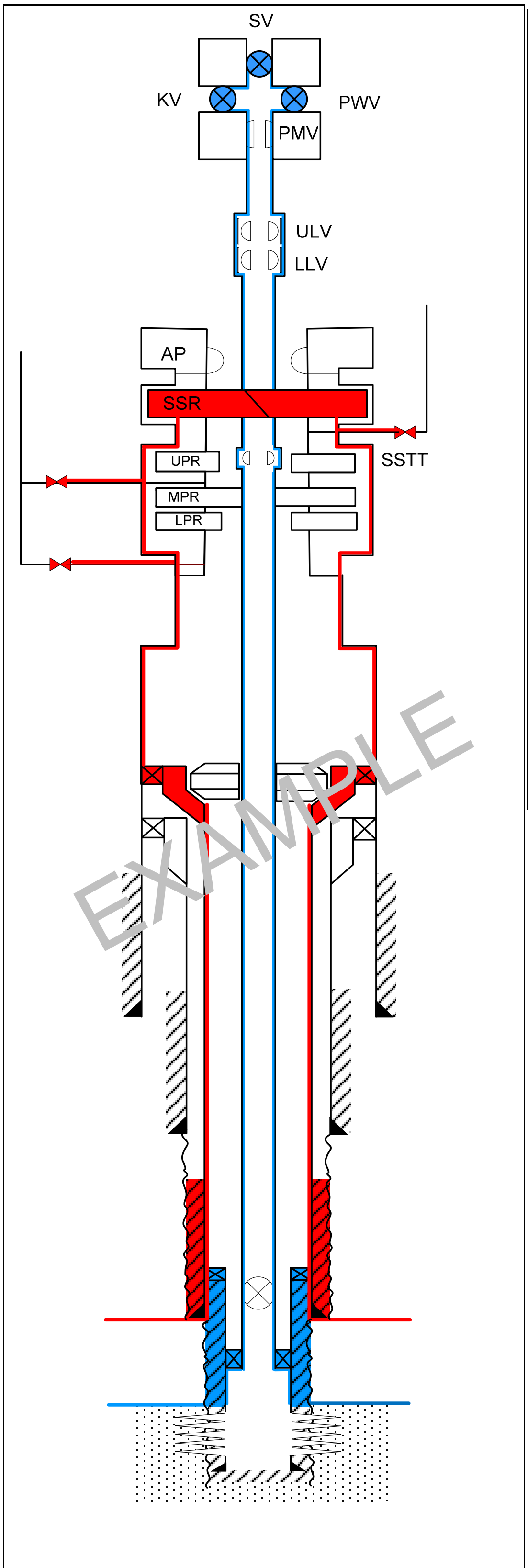
6.8 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



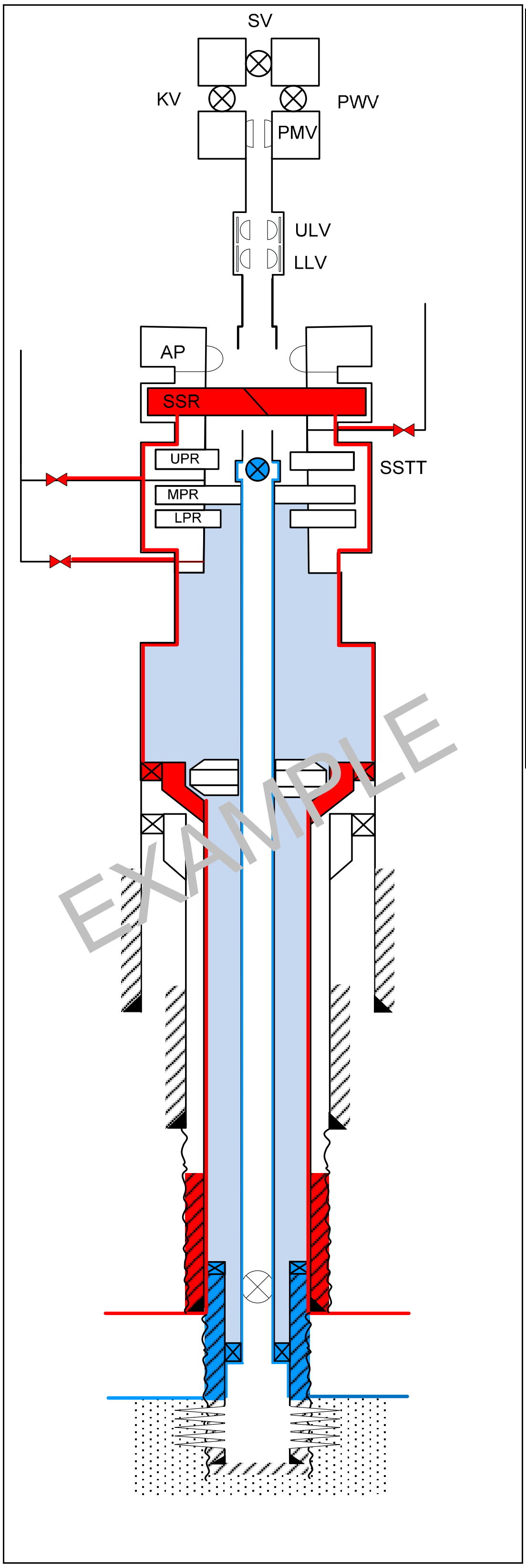
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing (liner) cement	22	
Casing (production liner)	2	
Liner top packer	43	
Well test packer	35	
Fluid column	1	
Downhole tester valve (body only)	46	
Well test string	27	
Subsea test tree	32	
Subsea lubricator valve	45	
Surface test tree	34	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Drilling BOP	4	

Figure 6.8.1 – Testing – flowing and build ups (overbalanced annulus fluid)



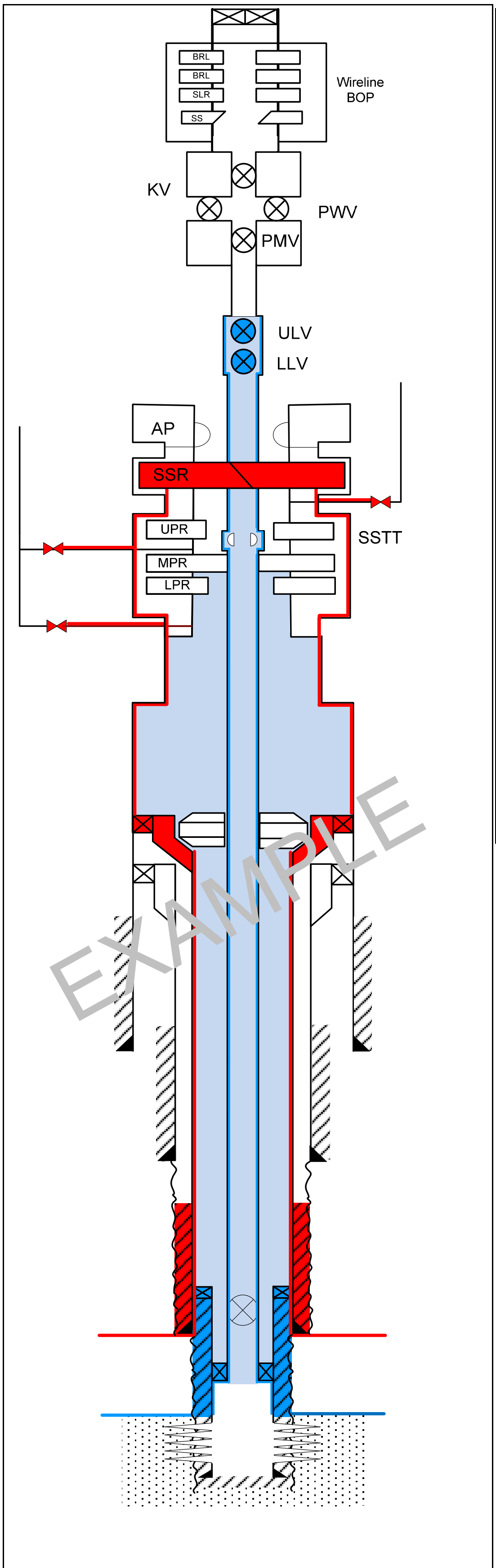
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing (liner) cement	22	
Casing (production liner)	2	
Well test packer	35	
Liner top packer	43	
Downhole tester valve (body only)	46	
Well test string	27	
Subsea test tree	32	
Subsea lubricator valve	45	
Surface test tree	34	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Drilling BOP	4	

Figure 6.8.2 – Testing – flowing and build ups (underbalanced annulus fluid)



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing (liner) cement	22	
Casing (production liner)	2	
Liner top packer	43	
Well test packer	35	
Fluid column	1	
Downhole tester valve (body)	46	
Well test string (below subsea test tree)	27	
Subsea test tree	32	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Drilling BOP	4	

Figure 6.8.3 – Testing – landing string disconnected



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing (liner) cement	22	
Liner top packer	43	
Casing (production liner)	2	
Well test packer	35	
Fluid column	2	
Downhole tester valve (body)	46	
Well test string	27	
Subsea test tree	32	
Well test string	27	
Subsea lubricator valve	45	
Surface test tree	34	
Secondary well barrier		
In-situ formation	51	
Fluid column	1	
Casing cement	22	
Casing	2	
Wellhead	5	
Drilling BOP	4	

Figure 6.8.4 – R/U and R/D WL equipment and changing WL during well testing

7 Completion activities

7.1 General

This section covers the requirements and guidelines pertaining to well integrity during completion activities.

This activity commences after the well is drilled to total depth and logged. The completion phase ends when the tree is installed, well barriers tested and the well handed over to the production organization.

The purpose of this section is to describe the establishment of well barriers by the use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

7.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (7.8).

7.3 Well barrier acceptance criteria

The following list defines specific requirements and guidelines for well barriers:

a) All WBEs, control lines and clamping arrangements shall be resistant to environmental loads (chemical exposure, temperature, pressure, mechanical wear, erosion, vibration, etc.).
b) All production or injection wells shall be equipped with a tree.
c) A DHSV shall be installed in the completion string for all wells penetrating a hydrocarbon bearing reservoir or wells with sufficient reservoir pressure to lift fluids to surface or seabed level (including supercharged injection formations).
d) All production or injection wells shall have an annular seal between the completion string and the casing or liner, i.e. production packer.
e) It shall be possible to install a tubing hanger plug (or a shallow set tubing plug) and a deep set tubing plug in the completion string.
f) The tubing bore shall have continuous pressure transmitter monitoring at the wellhead/ tree level with alarms.
g) The pressure in the A-annulus shall have continuous pressure transmitter with alarms at the wellhead / tree level with safe operating pressure limits defined.
h) All accessible annuli shall be equipped with pressure gauge(s) with safe operating pressure limits defined.

7.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 17 – Additional EAC requirements

Table no.	Element name	Additional features, requirements and guidelines
1	Fluid column	There shall be sufficient fluid, including minimum 100 % well volume, available on the location to maintain the minimum acceptable density.
4	Drilling BOP	The drilling BOP shall be capable of shearing all tubular (including any lines and/or wire strapped to the tubular) and sealing the wellbore. If this is not possible, (e.g. for completion assemblies), it shall be possible to: a) lower the assembly below the BOP, or b) drop the string below the BOP, or c) close the BOP on a suitable tubular within a distance equivalent to the length of a stand.

7.5 Well control action procedures and drills

7.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 18 – Well control action procedures

Item	Description	Comments
1.	Well influx/inflow (kick) or fluid loss while running or pulling the completion string	A stab-in (tubing) safety valve shall be prepared (with the same connections as the string) and be ready for use at all times.
2.	Running non-shearable items across BOP shear rams	
3.	Running completions with multiple control lines	
4.	Running and installation of sand screens	Surge and swab effects. Inability to shut-in the well with perforated pipe through the BOP.
5.	Planned or emergency disconnect of marine riser	Applies to subsea operations
6.	Drive or drift-off	Applies to DP vessels
7.	Anchoring failure	Loss of one or more anchors/ anchor chains

7.5.2 Well control action drills

The following well control action drills should be performed:

Table 19 – Well control action drills

Type	Frequency	Objective	Comments
Kick drill – completion	Once per crew before start-up of main operation	Response training to an influx while running lower or upper completion	Use procedure which covers the upcoming operation(s).
Emergency disconnect of marine riser (including SSTT if used) drill	Once per crew as soon as practical after rig-up	Response training	Without physically disconnecting the riser, including SSTT if used, simulating all the steps required for planned and emergency disconnect

7.6 Completion string design

7.6.1 General

All completion, liner and tie-backs strings shall be designed to withstand all planned and/or expected stresses, including those induced during potential well control situations. The design process shall be for the full life cycle of the well, including abandonment. Degradation of materials shall be taken into consideration. The design basis and margins shall be known and documented.

All components of the completion string including connections shall be subject to load case verification. Weak points shall be identified and documented.

The completion design shall accommodate permanent abandonment.

7.6.2 Design basis, premises and assumptions

The following shall be assessed to establish the dimensioning parameters for the design process:

a) reservoir pressure during well life, including reservoir fluids and/or gas properties;
b) planned well trajectory and bending stresses induced by well doglegs and curvature;
c) casing design;
d) well control and maximum well kill pressure;
e) planned production and/or injection rate and associated fluid and/or gas properties;
f) annulus pressure management of accessible annuli;
g) H_2S and/or CO_2 including potential reservoir souring during life of well;
h) fluids compatibility and corrosion;
i) well life expectancy;
j) material selection;
k) sand control requirements;
l) artificial lift requirements;
m) potential hydrate, scale and asphaltene deposits and chemical injection requirements;
n) loads induced by well services and operations including well interventions, scale squeeze, fracturing and/or other chemical treatments;
o) geo-tectonic forces;
p) well suspension and abandonment requirements;
q) experience from previous wells in the area or similar wells.

7.6.3 Load cases

When designing for burst, collapse and axial loads, cases applicable for the planned activity shall be applied. Every well type shall have a tubing stress analysis performed. The following load cases shall be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed:

Table 20 – Load cases

Item	Description	Comments
1.	Pressure testing of the completion string	
2.	Pressure testing A-annulus	Testing of tubing hanger seals from below and production packer from above (as a minimum to MAASP)
3.	Shut-in of well	
4.	Dynamic flowing and injection conditions	Special focus on temperature effects for production and injection wells (water, gas, WAG and simultaneous WAG)
5.	Injection	Maximum injection system pressure (WDP)
6.	Production	Should check tubing collapse as a function of minimum tubing pressure (plugged perforations/ low test separator pressure/ depleted reservoir pressure) combined with a high operating annulus pressure (minimum to MAASP) Consider effects due to erosion/ corrosion
7.	Bullheading/ pumping	Well killing, stimulation, fracturing
8.	Overpull	Stuck string, shear rating of pins/ rings. Tensile strength of all completion components, including equipment connections.
9.	Firing of TCP guns	
10.	Temperature effects	All closed volumes with special attention to start-up and shut-in of well
11.	Artificial lift	Shut-in of annulus by closing ASV and evacuated annulus above gas lift valve Maximum injection system pressure

7.6.4 Minimum design factors

Tubing shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The minimum design factors shall be as described in section 4.3.6.

7.6.5 Completion equipment – emergency shut-down system

The following completion string equipment shall be classified as part of the installation's emergency shutdown system:

a) DHSV;
b) ASV or other fail-safe closed devices, if installed;
c) tree valves - master and wing valves;
d) tree/wellhead valves serving chemical injection lines;
e) tree/wellhead valves serving annulus gas lift valve.

7.7 Other topics

7.7.1 Subsea wells

When establishing the maximum differential pressure (for casing or tubing) at seabed level, the A-annulus pressure at the seabed shall not include the hydrostatic pressure (seawater) from seabed to surface.

7.7.2 Gas lift wells

The large volume of pressurised hydrocarbon gas in both surface lines and in the A-annuli represents a substantial risk to a platform. The volume of released hydrocarbon gas due to accidental damage to the tree, wellhead or surface lines shall be minimized.

All gas lift wells shall have two barriers to prevent release of the A-annulus gas volume. Gas lift platform wells shall have an ASV installed in the A-annulus. A downhole gas lift injection valve (if qualified as a WBE) can be used as an alternative to an ASV in subsea wells.

The following apply:

a) An analysis shall be performed to assess the risk of release of hydrocarbon gas to the surroundings (air, water column) if the wellhead / production casing barrier elements are lost. The total risk assessment for the installation shall include this analysis.
b) Casing and tubing exposed to gas-lift gas should have ISO 13679 CAL IV qualified connections that are correctly made up and tested.
c) All wells shall have continuous monitoring of the B-annulus with alarms. For subsea wells the B-annulus shall be designed to withstand the effect of thermal induced pressure (APB).

7.7.3 HPHT wells

Specification and qualification criteria for equipment and fluids to be used or installed in a HPHT well shall be established, with particular emphasis on:

a) sealing capability of metal to metal seals as a function of wellbore fluids, pressure and temperature;
b) clearance and tolerances as a result of temperature and differential pressure exposure;
c) deterioration of elastomer seals and components as a result of temperature/pressure exposure time and wellbore fluids;
d) packer fluid selection and design including hydrate prevention;
e) cement strength retrogression;
f) wellhead growth;
g) impact of depleted reservoir,
h) stability of explosive and chemical perforating charges as function of temperature, pressure and exposure time.

7.7.4 Injection / disposal wells

Injection / disposal wells are designed and used to inject liquids (water, brines, slurries or similar) and/or gases (including WAG, SWAG) into dedicated formation(s).

The well shall be constructed such that the injected media will be contained within the targeted formation zone (reservoir) without risk of out of zone injection.

For wells injecting at a pressure greater than the fracture closure pressure at the injection depth, the following applies:

a) the production packer shall be installed at a depth ensuring the injection or a casing leak below the production packer will not lead to fracturing of the cap rock or leak to shallower formation when applying maximum injection pressure (see figure 7.7.4.1);
b) the casing/liner cement shall be logged and as a minimum have bonding from upper most injection point to 30 m MD above top reservoir;
c) it shall be documented that the injection will not result in a reservoir pressure exceeding the strength of the cap rock.

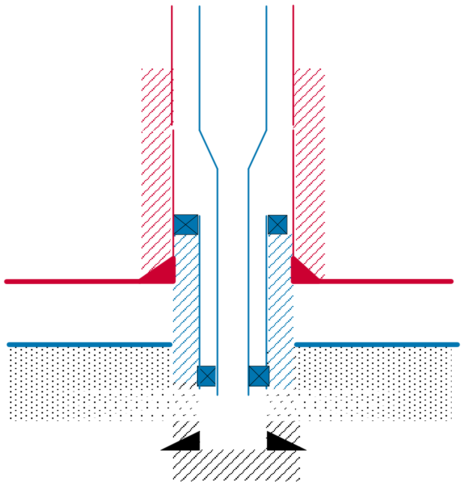


Figure 7.7.4.1

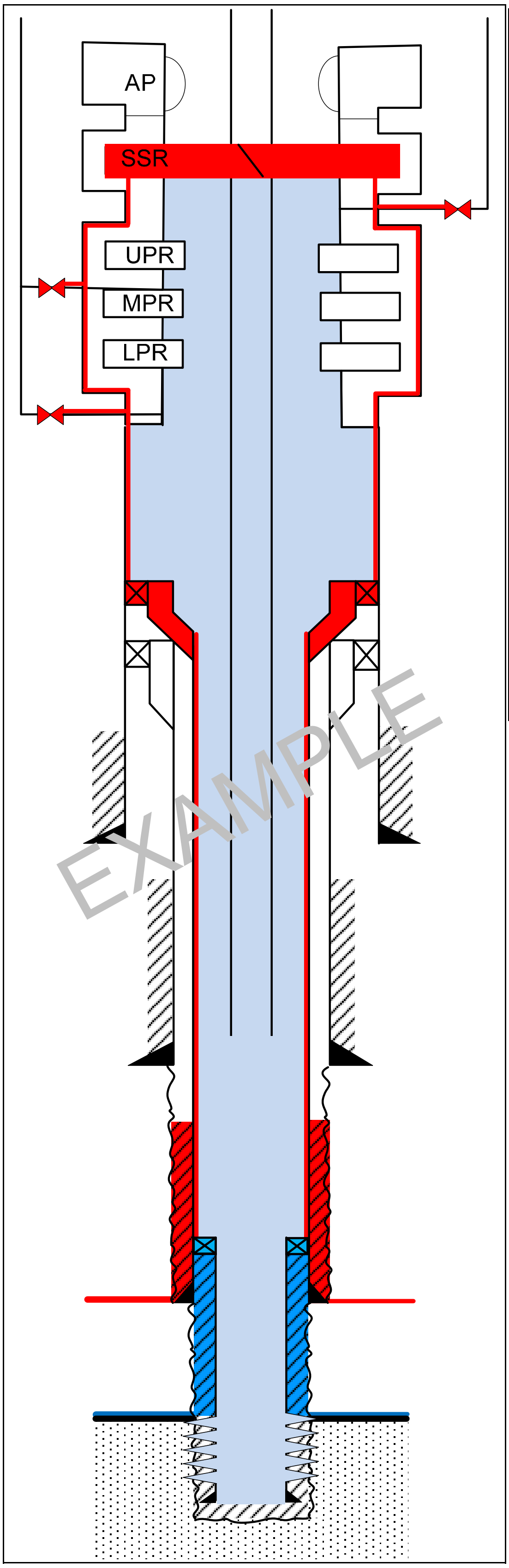
7.7.5 Multipurpose wells

A multipurpose well is defined as a well that has transport of media to or from a formation interval via the A-annulus in addition to transport through the tubing. All multipurpose wells shall have two well barriers to prevent release of the A-annulus media. The following requirements and guidelines apply:

a) All platform wells shall have an ASV installed in the A-annulus communicating to a HC bearing reservoir or zones with sufficient reservoir pressure to lift fluids to surface or seabed level (including supercharged injection formations).
b) All wells shall have continuous monitoring of the B-annulus with alarms. For subsea wells the B-annulus shall be designed to withstand the effect of thermal induced pressure (APB).The well shall be constructed such that the injected media will be contained within the targeted formation zone (reservoir) without risk of out of zone injection.
c) The production casing shall be designed as production tubing for planned well fluid exposure during the well life cycle.
d) The intermediate casing, casing cement, and the formation shall be capable of withstanding a leaking production casing scenario.

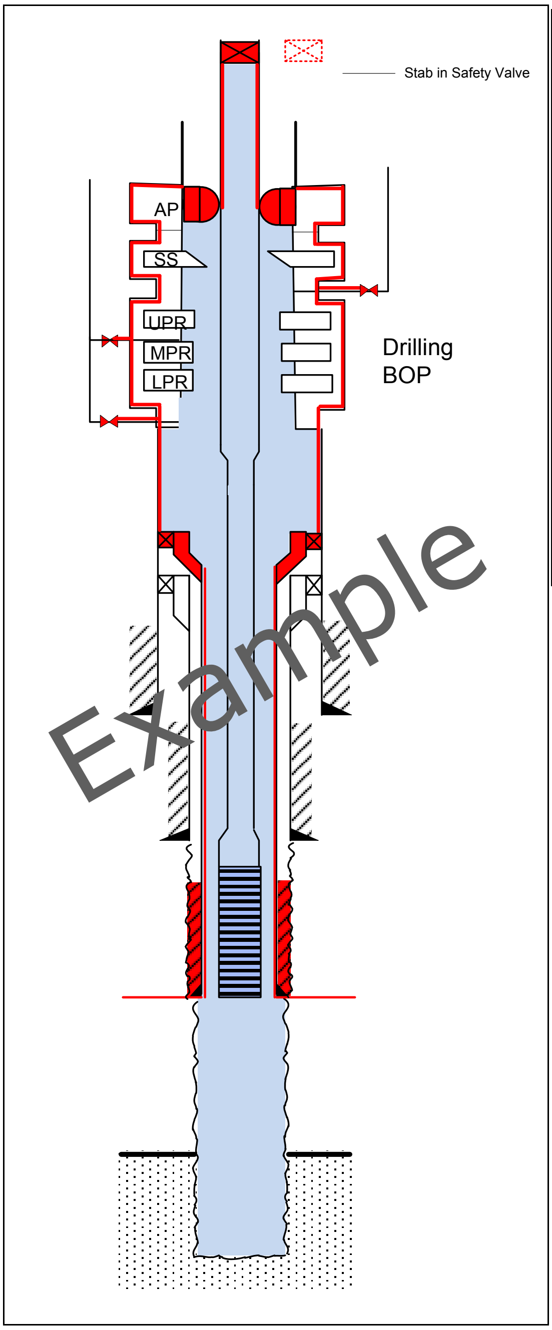
7.8 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



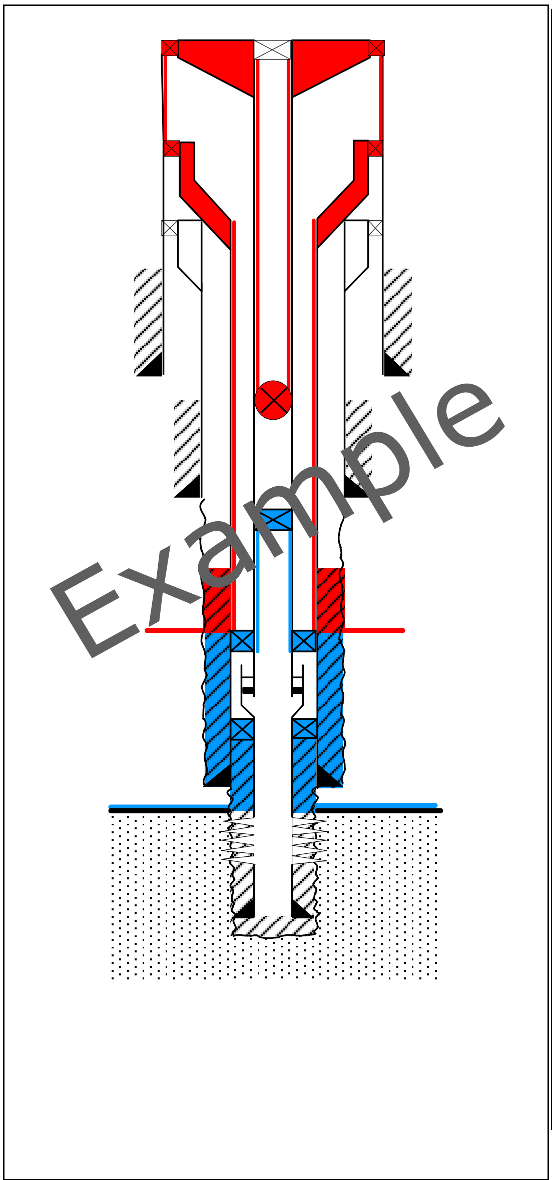
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
In-situ formation	51	
Casing (liner) cement	22	
Casing (production liner)	2	
Liner top packer	43	
Secondary well barrier		
In-situ formation	51	
Casing (liner) cement	22	
Liner	2	
Liner top packer	43	
Casing	2	
Casing cement	22	
Wellhead	5	
High pressure riser	26	
Drilling BOP	4	

Figure 7.8.1 – Running open end completion string



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser	26	.
Drilling BOP	4	
Completion string	25	
Stab-in safety valve	40	

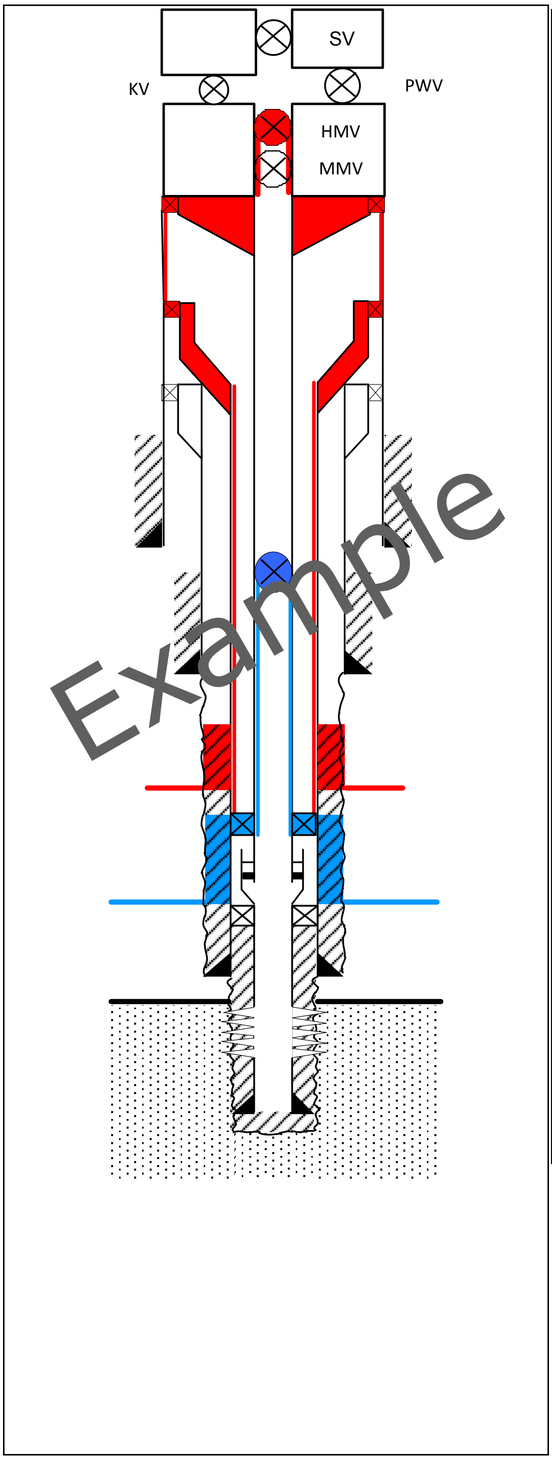
Figure 7.8.2 – Running non-shearable item through BOP



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Liner cement	22	
Liner	2	
Liner top packer	43	
In Situ formation	51	
Production casing cement (shoe to prod.packer)	22	
Production casing (below prod.packer)	2	
Production packer	7	
Completion string	25	
Deep set tubing plug	6	
Secondary well barrier		
In-situ formation	51	
Production casing cement (above prod.packer)	22	
9 5/8” Casing (above production packer)	2	
Wellhead	5	
Tubing hanger	10	
Completion string	25	
DHSV*	8	
Tubing hanger plug	11	

*A debris plug shall be installed in the tubing hanger production bore if the upper well barrier is a DHSV.

Figure7.8.3 – Pulling BOP and landing vertical subsea production tree



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (below production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
Completion string component	29	
DHSV / control lines	8	
Secondary well barrier		
In-situ formation	51	
Casing cement (above production packer)	22	
Casing (above production packer)	2	
Wellhead (Production casing hanger with seal assembly)	5	
Wellhead annulus valve	12	
Tubing hanger (body seals)	10	
Wellhead (WH/XT Connector)	5	
Tubing hanger (neck seal)	10	
Surface production tree	33	

Figure 7.8.4 – Completed platform production well

8 Production activities

8.1 General

This section covers requirements and guidelines pertaining to well integrity during production and injection from or to a reservoir. It describes the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

The activity starts after the well construction/well intervention organization has handed the well over to the production organization and concludes with a handover back to drilling and well organization for intervention, workover or abandonment.

8.2 Well barrier schematics

A WBS shall be prepared and maintained for each completed well. Examples of WBSs for selected situations are presented at the end of this section (see section 8.9).

Any change in well barrier status or failure of a WBE shall be documented on the WBS.

For wells that are injecting with a higher downhole pressure than the formation (cap rock) integrity, the maximum reservoir pressure shall be stated on the WBS (see section 7.7.4 for required well design for such situations).

See Norwegian Oil and Gas 117 – Recommended Guidelines for Well Integrity.

8.3 Well barrier acceptance criteria

Wells with a source of inflow/reservoir shall have two independent mechanical well barriers. This also applies to wells which could develop an inflow potential due to injection. Wells with no source of inflow/reservoir shall as a minimum have one mechanical well barrier. For wells with only one mechanical barrier, inflow tests at pre-determined intervals are required to confirm that the well will not flow.

All wells shall be well integrity categorised. See Norwegian Oil and Gas 117 – Recommended Guidelines for Well Integrity.

8.4 Well barrier elements acceptance criteria

The status of the WBEs shall be known through registration of tubing and annulus pressure(s), temperature, flow rates, fluid compositions and pressure/leak testing of WBEs. The acceptance criteria for each WBE shall be established and be in accordance with section 15. Unless leak rate is measured directly, the acceptance criteria for allowed leak rates shall be converted to pressure units per time. The effect of variation of gas/oil ratio or media composition over time should be included.

When it is not possible to monitor or test the WBE in a well, then requirements in section 9 apply for these elements.

When leak testing, a 70 bar pressure differential is preferred for all WBEs with an allowable leak rate. The WBE to be tested may have less differential pressure applied, providing:

a) the allowable leak rate is adjusted (reduced) accordingly; or
b) the maximum wellhead pressure is less than 70 bar.

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 21 – Additional EAC requirements

Table no.	Element name	Additional features, requirements and guidelines
8	Downhole safety valve	The liquid/gas composition above the valve(s) to be tested should be known. If the composition is not known, the worst case composition scenario shall be used. For gas-liquid combinations special calculation formulas should be developed. Unless the leak rate is measured directly, the acceptance criteria should be converted to pressure units per time for the individual wells.
9	Annulus safety valve	
29	Completion string component (gas lift valve)	
31	Subsea tree	Tree valves of floating gate design shall be tested in the direction of flow from reservoir. The test of master valves may be omitted if the shut-in pressure is insufficient to give a conclusive test. This is provided the wing valves are tested in the flow direction by pressuring up the XT cross. Tree valves, annulus access valves and chemical injection valve (CIV) tests may utilise the API RP 14B leak rate acceptance criteria providing the observation volume is adequately large to provide a conclusive test and the valves are connected to a closed system downstream of the valve. Valves bordering the external environment / surroundings shall have zero leak rate.
33	Surface tree	
29	Completion string component (chemical injection valve)	
12	Wellhead annulus access valves	

8.5 Well control action procedures and drills

Well control action procedures shall be established for different scenarios. Actions for securing the well and neighbour wells shall be clearly stated for well barrier failures.

Generic procedures for killing the well shall be available at all times and a risk based evaluation of the needed response time. The blowout contingency plan shall be maintained including possibilities of relief well drilling.

Upon confirmation of loss of the primary or secondary well barrier, the well shall be shut-in and the remaining well barrier verified. Only activities related to the re-establishment of the well barrier shall be carried out on the effected well. Multiple well barrier failures on the same well shall immediately result in an alert to the emergency response organization.

If the risk of loss of containment is significantly increased by shutting in the well, the well may be kept on production until the well barrier is re-established. Continued production shall be based on a risk assessment that demonstrates:

a) continued production reduces the probability of further well barrier degradation;
b) risk of additional well barrier failures is kept to a minimum compared to shutting in the well.

There are no drills described with this section.

8.6 Well handover documentation

Any well design feature of significance to the safety or operating efficiency of the well shall be clearly documented and communicated when transferring the responsibility of the well from the well construction team to the production operations team. These should contain the following:

a) well identification number;
b) name of organizational unit releasing and accepting the responsibility of the well (with signature and date);
c) well type (e.g. production, gas or water injector, disposal well, etc.);
d) installation certificates, including valve, pressure and fluid status;

e) well diagrams:
   1. WBS;
   2. well completion schematic;
   3. wellhead and tree schematics.

f) well construction data and well barrier test charts:
   1. casing, tubing and completion component data (depth, sizes etc.);
   2. cement data;
   3. wellhead data;
   4. tree data;
   5. perforating details;
   6. equipment details such as identification or serial number, including tag numbers for instrumentation and equipment subject to periodic maintenance.

g) operating limits such as design life, flow rates, pressures, temperature, fluid compositions;
h) minimum and maximum operating annulus pressure;
i) reference to test procedures, well start up procedures and any special operating considerations;
j) deviations which are identified and valid for the well; and
k) well integrity categorization.

When a well is handed over between organizations (for example between production and well interventions, a simplified documentation package should include:

l) well identification number;
m) name of organizational unit releasing and accepting the responsibility of the well (with signature and date);
n) reason for handover;
o) current tubing and annulus pressure(s);
p) current valve status (open/closed), including pressure and fluid status;
q) information with regards to last verification test of WBE;
r) current well barrier schematic;
s) information of any constructional or operational changes since last handover (e.g. changed XT valve, updated operational limit values, etc.);
t) deviations; and
u) well integrity categorization.

8.7 Operating and monitoring

All wells shall be operated within the safe operating limits, defined type of well service (e.g. production, injection) and well design life.

Alarms shall be used when required to ensure well integrity. The alarm levels shall be set within the safe operating limits. The alarm limits shall be evaluated for situations in which automatic shutdown is required. For injection wells, special considerations shall be given to avoid risk of out of zone injection.

If the defined type well service or established operating parameters are planned to be changed, the well design shall be checked to assure that the existing design is able to handle the new scenario and loads. A MoC shall be carried out before changing any of these parameters.

As part of the well planning the following shall be established prior to well start up:

a) a WBE maintenance program with test procedures and acceptance criteria;
b) well start up and shut-in procedures;
c) safe operating range(s) and a program for monitoring of well integrity parameters, including:

1. pressure in tubing and accessible annuli;
2. temperature (well, flowline);
3. production / injection rates;
4. composition of production and injection fluid (including any production/injection through annuli); and
5. composition of annulus fluids.

All fluids shall be compatible with the exposed well material and existing well fluid composition.

Tubing and accessible annuli pressures, rates and temperatures shall be trended and compared to detect any leaks or anomalies. Valve positions shall be known at all times and normally kept in a position to enable monitoring.

8.7.1 Leak and function testing of well barrier elements

The ESD function shall be tested before operating the well. A sequential shutdown of valves is required and shall be verified. The requirements for closure time of ESD valves shall be assessed and defined for each installation and field, based on risk and operating well conditions.

All valves, available testable seals and lines which are part of the primary or secondary well barriers shall have a maintenance program and be periodically tested to verify its function and integrity according to section 15.

Minimum test frequency is defined for the WBEs in section 15. The test frequency should be regulated based on:

a) experience data;
b) changes of the well flow composition increasing risk of deposits, scale, corrosion, erosion and high production and injection rates.

The historic performance and reliability data used to justify a change in the test frequency shall be documented.

If a safety critical valve or seal fails, the root cause should be established and actions shall be taken to repair. Preventative maintenance/actions shall be implemented to reduce the likelihood of new failures. If a safety critical valve type has a failure rate on the installation which exceeds 2% within a 12 month period, measures shall be taken to improve the reliability of the valve type in general.

8.7.2 Monitoring of well flow

The well flow / injection fluids shall be systematically monitored and analysed to detect changes that may negatively affect the WBE such as corrosion, erosion, scale and wax deposits, and emulsions.

8.7.3 Casing and tubing annuli

Maximum and minimum operating annulus pressures shall be defined for all accessible annuli. The operating pressure range shall be set to ensure that the design limitations (load cases) and verified test pressures are not exceeded for the individual annuli/ exposed WBE. For annuli open to the formation, the minimum formation stress should not be exceeded unless this is a planned contingency during the well design (e.g. subsea wells where B-annulus is not cemented)

The following shall be considered when defining the operating range:

a) the effect of temperature changes (well stream, ambient) on the annuli pressures, especially during emergency shut down situations;
b) the available response time to bleed off or top up annuli;
c) variation in the tubing and annuli fluid densities; and
d) occurrence of pressure communication between annuli or escalation of risk if such communication should occur.

The pressure in all accessible annuli shall be monitored and maintained within minimum and maximum pressure range limits. All accessible annuli should be maintained with positive pressure for leak detection and pressures should be kept with differential pressure between all annuli.

The annulus bleed system shall be liquid filled at all times if possible. When gas has been bleed off from the annulus, the annulus bleed system should be replenished with liquid. Hydrate inhibition shall be considered.

See Norwegian Oil and Gas Association Guideline no. 117 – Recommended Guidelines for Well Integrity for defining the annulus pressure operating envelopes.

8.7.4 Sand production

It shall be assumed that wells in sandstone reservoirs may produce sand. Sand production from each well should be monitored continuously or at frequent intervals (downhole, subsea or at surface). Threshold values for maximum allowable sand production should be established. Erosion loss in the flow conduit from the reservoir and to the entry of the first stage separator should be estimated or measured, and compared with maximum allowable wear loss.

When sand production occurs, efforts should be taken to reduce the effect of sand erosion.

8.7.5 Scale/asphaltenes/wax

Scale, asphaltene and wax deposits in the well could cause failure of WBEs. The effect of injection/produced water on the production performance shall be known through studies and chemical analysis. When the operating conditions are within the scale formation regime, injection of scale dissolver and/or a scale inhibition programs shall be considered.

Injected chemicals shall have a confirmed compatibility with all well component materials and fluids that will be exposed including chemical injection lines.

8.7.6 Hydrates

The potential for forming of hydrates in flow conduits shall be assessed, with particular focus on DHSVs, tree valves, annulus bleed-down system and other WBEs that may be affected. Procedures for hydrate prevention (injection of anti-freeze agents) shall be established, including leak testing of valves, and when shutting in a well for a longer period.

8.8 Anomalies

The event of a possible loss of a well barrier, deviation from normal or predicted pressure behaviours, or change in fluid compositions that could negatively affect the well barriers, shall trigger an evaluation of the event.

Anomalies shall be evaluated to determine the cause and effects, considering the following:

a) method of normalization of the situation and restoring two well barriers;
b) gas and/or liquid leak rate across the well barrier;
c) ensure the acceptance criteria for qualifying the well barrier is maintained;
d) blowout potential, should the remaining well barrier envelope fail;
e) verification of well design to ensure the present design can manage new load scenarios; and
f) ensure the operating limits are still valid.

Any further deterioration or additional failure shall not significantly reduce the possibility of containing the hydrocarbon/pressure and normalising the well.

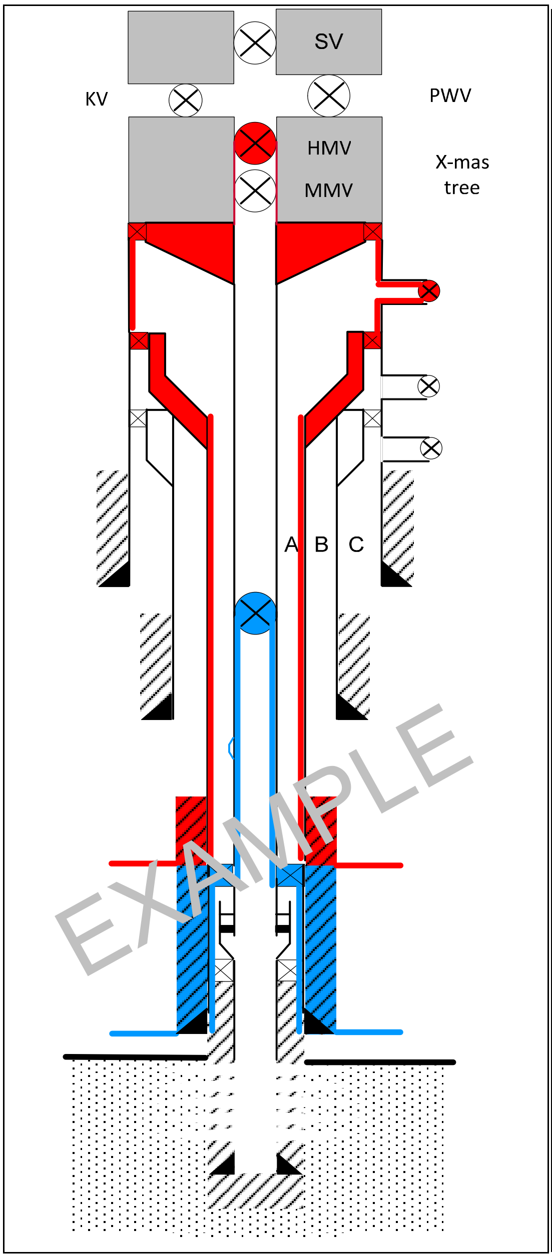
If the well barrier status or monitoring ability is altered, production/injection shall only continue when supported by a risk assessment and MoC process.

When there is a risk of corrosion or erosion occurring, wall thickness loss calculations shall be performed. The need for periodic systematic measurements, such as calliper runs, shall be evaluated. If wall thickness loss exceeds the design criteria, new load calculations shall be performed and/or operational limits re-evaluated.

See Norwegian Oil and Gas Association Guideline no. 117 - Recommended Guidelines for Well Integrity. for guidance on handling of annulus leaks and sustained casing annuli pressures.

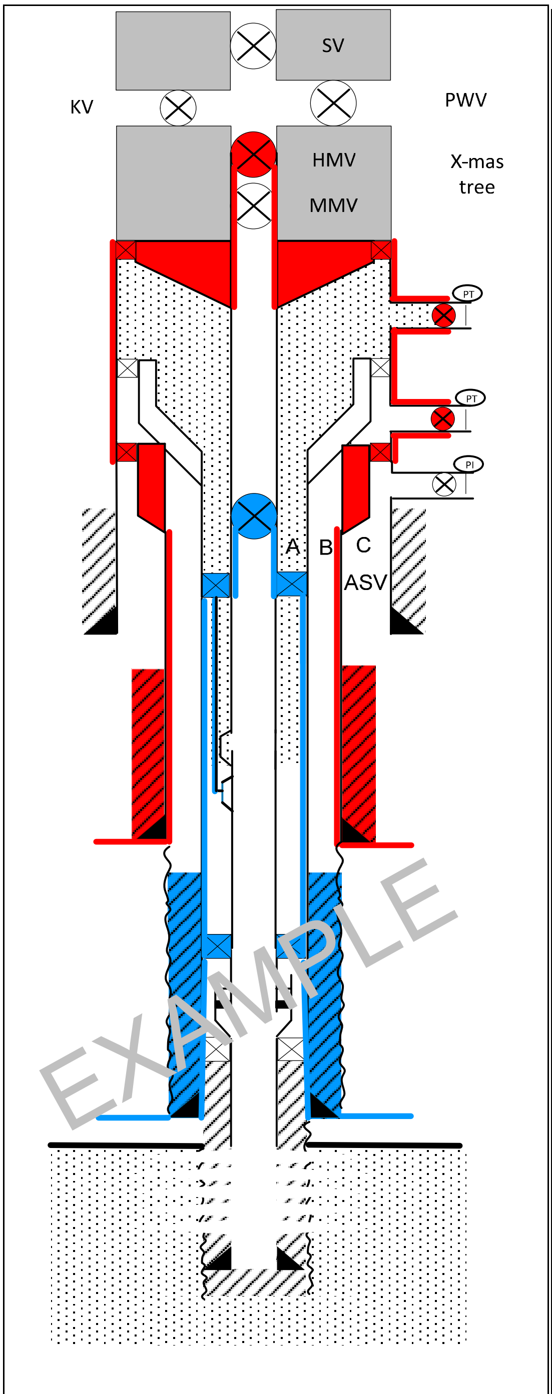
8.9 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



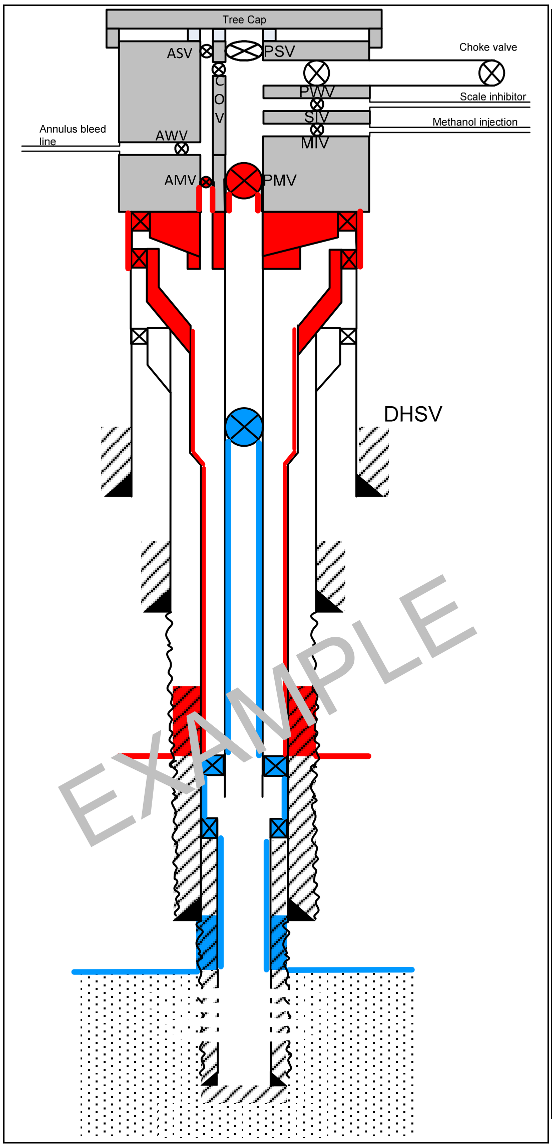
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Casing cement (shoe to production packer)	22	n/a after initial verification
Casing (below production packer)	2	n/a after initial verification
Production packer	7	Continuous pressure monitoring of A-annulus
Completion string	25	Continuous pressure monitoring of A-annulus
Completion string component	29	Periodic leak testing.
DHSV (including control line)	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Casing cement (above production packer)	22	Daily monitoring of B-annulus
Production casing (above production packer)	2	Daily monitoring of B-annulus
Production casing hanger with seal assembly	5	Daily monitoring of B-annulus/ Periodic leak testing
Wellhead (annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals)	10	Periodic leak testing and continuous pressure monitoring of A-annulus
Wellhead (WH/Tree Connector)	5	Periodic leak testing
Tubing hanger (neck seal)	10	Periodic leak testing
Surface tree	33	Periodic leak testing of valves AC: xx bar/xx min.

Figure 8.9.1 – Platform production/injection/observation well capable of flowing



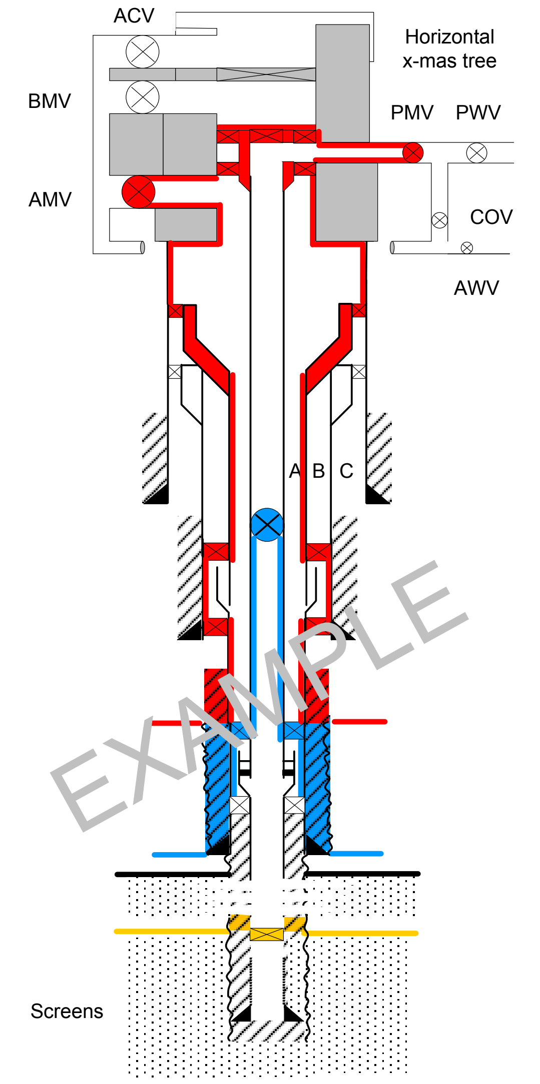
Well barrier elements	EAC table	Verification/Monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Casing cement	22	n/a after initial verification
Production casing	2	Continuous pressure monitoring of B-annulus
Production packer	7	n/a after initial verification
Completion string component (CIV and CI line)	29	Periodic leak testing
ASV (including control line)	9	Periodic leak testing. AC ASV: xx bar/xx min.
Completion string (Between ASV and DHSV)	25	Periodic leak testing
DHSV / control line (including control line)	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Intermediate casing cement	22	Daily monitoring of C-annulus
Intermediate casing	2	Daily monitoring of C-annulus
Intermediate casing hanger with seal assembly	5	Daily monitoring of C-annulus/ Periodic leak testing
Wellhead (A-annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Wellhead (B-annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals)	10	Periodic leak testing and continuous pressure monitoring of A-annulus
Wellhead (WH/tree connector)	5	Periodic leak testing
Tubing hanger (neck seal)	10	Periodic leak testing
Surface tree	33	Periodic leak testing of valves AC: xx bar/xx min.

Figure 8.9.2 – Platform production well on gas lift with ASV (GLV not qualified)



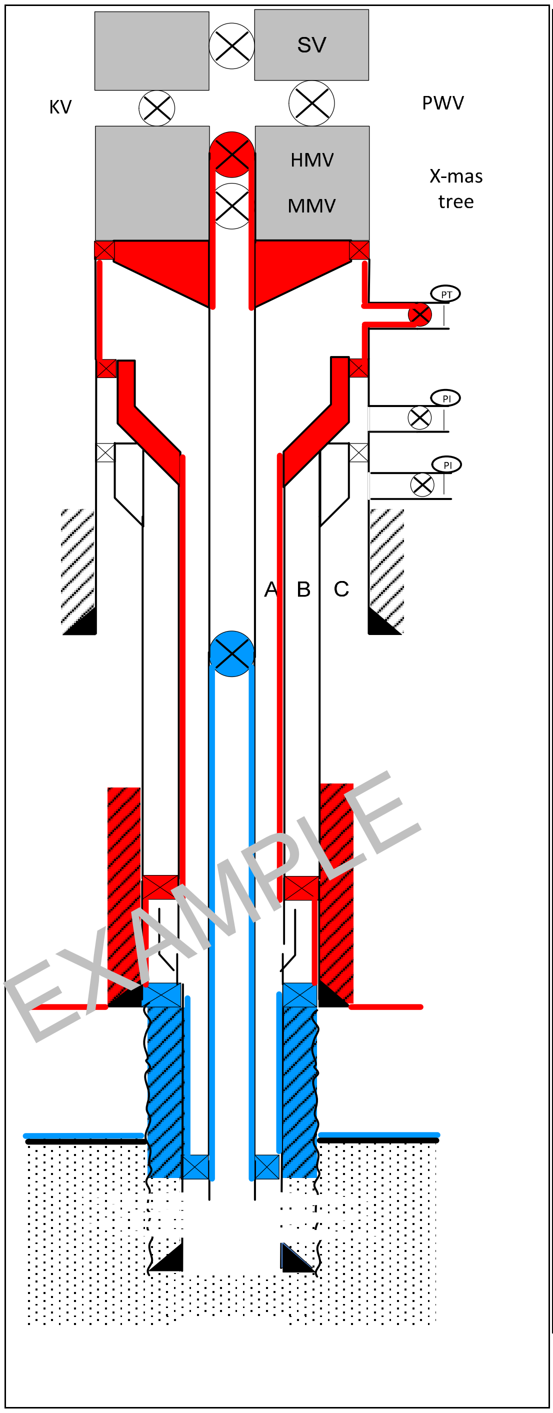
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Liner cement (top reservoir to production casing shoe)	22	n/a after initial verification
Casing (production liner)	2	n/a after initial verification
Liner hanger packer	7	n/a after initial verification
Casing (between production packer and liner hanger packer)	2	n/a after initial verification
Production packer	7	Continuous pressure monitoring of A-annulus
Completion string	25	Continuous pressure monitoring of A-annulus
DHSV / control line	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Production casing cement (above production packer)	22	daily monitoring of the B-Annulus
Production casing (above production packer)	2	Continuous pressure monitoring of A-annulus
Production casing hanger with seal assembly	5	Continuous pressure monitoring of A-annulus
Tubing hanger (seals)	10	Continuous pressure monitoring of A-annulus
Wellhead (WH/tree connector)	5	Continuous pressure monitoring of A-annulus
Subsea tree	31	Periodic leak testing of valves AC: xx bar/xx min.

Figure 8. 9.3 – Subsea production well with a vertical tree



Well barrier elements	EAC table	Verification/monitoring
Crossflow well barrier		
In-situ formation (cap rock between reservoirs)	51	n/a after initial verification
Casing cement (liner cement behind plug)	22	n/a after initial verification
Casing (liner behind plug)	2	n/a after initial verification
Deep set plug	6	n/a after initial verification
Primary well barrier		
In Situ Formation (at casing shoe)	51	n/a after initial verification
Production casing cement (shoe to production packer)	22	n/a after initial verification
Production casing (below production packer)	2	n/a after initial verification
Production packer	7	Continuous pressure monitoring of A-annulus
Completion string	25	Continuous pressure monitoring of A-annulus
DHSV / control line	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Production casing cement (above production packer)	22	n/a after initial verification
Production casing (liner above production packer)	2	Continuous pressure monitoring of A-annulus
Liner hanger packer	7	Continuous pressure monitoring of A-annulus
Intermediate casing (between liner packer and tie-back packer)	2	Continuous pressure monitoring of A-annulus
Tie-back packer	7	Continuous pressure monitoring of A-annulus
Production casing (above tie back packer)	2	Continuous pressure monitoring of A-annulus
Production casing hanger with seal assembly	5	Continuous pressure monitoring of A-annulus
Tubing hanger with seals	10	Continuous pressure monitoring of A-annulus
Wellhead (WH/tree connector)	5	Continuous pressure monitoring of A-annulus
Subsea tree	31	Periodic leak testing of valves AC: xx bar/xx min.

Figure 8.9.4 – Subsea production well with a horizontal tree and zonal isolation



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	n/a after initial verification
Production packer	7	Continuous pressure monitoring of A-annulus
Liner cement (production packer to production casing shoe)	22	n/a after initial verification
Casing (production liner)	2	Continuous pressure monitoring of A-Annulus
Liner hanger packer	7	Continuous pressure monitoring of A-Annulus
Completion string	25	Continuous pressure monitoring of A-annulus
DHSV / control line	8	Periodic leak testing. AC DHSV: xx bar/xx min.
Secondary well barrier		
In-situ formation	51	n/a after initial verification
Intermediate casing cement	22	Daily monitoring of C-annulus
Intermediate casing (between liner top packer and tie-back packer)	2	Continuous pressure monitoring of A-annulus
Tie-back packer	7	Daily monitoring of B-annulus
Tie-back production casing	2	Daily monitoring of B-annulus
Production liner hanger with seal assembly	5	Daily monitoring of B-annulus. Periodic leak testing
Wellhead (A-annulus valve)	12	Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals)	10	Periodic leak testing and continuous pressure monitoring of A-annulus
Wellhead (WH/XT Connector)	5	Periodic leak testing
Tubing hanger (neck seal)	10	Periodic leak testing
Surface tree	33	Periodic leak testing of valves AC: xx bar/xx min.

NOTE For wells that are injecting with a higher downhole pressure than the cap rock barrier integrity, the maximum reservoir pressure shall be stated on the WBS. Design requirements: Production packer to be set below cap rock.

Figure 8.9.5 – Injection well with production packer in cemented liner

9 Abandonment activities

9.1 General

This section covers requirements and guidelines pertaining to well integrity during:

a) suspension of well activities and operations;
b) temporary abandonment of wells;
c) permanent abandonment of wells; and
d) permanent abandonment of a section in a well (sidetracking, slot recovery) to construct a new wellbore with a new geological well target.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner, with focus on isolation of permeable formations/reservoirs/sources of inflow.

Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same. The choice of WBEs may be different to account for abandonment time, and ability to re-enter the well, or resume operations after temporary abandonment.

9.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

A final verified WBS for the well status upon completion of operations shall be in place.

Examples of WBSs for selected situations are presented.

9.3 Abandonment design

9.3.1 Design basis, premises and assumptions

All sources of inflow shall be identified and documented.

All WBE used for plugging of wells shall withstand the load and environmental conditions they may be exposed to for the abandonment period.

The design basis should include:

a) Well configuration (original and present) including depths and specification of formations which are sources of inflow, casing strings, casing cement, wellbores, sidetracks.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, current and in an eternal perspective).
c) Logs, data and information from cementing operations.
d) Formations with suitable WBE properties (e.g. strength, impermeability, absence of fractures and faulting).
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene or similar issues.

The design and placement of WBE consisting of cement or alternative materials should account for uncertainties relating to:

f) downhole placement techniques;
g) minimum volumes required to mix a homogenous slurry;
h) surface volume control;
i) pump efficiency/ -parameters;
j) contamination of fluids;
k) shrinkage of cement or plugging material;
l) casing centralization;
m) support for heavy slurry; and
n) WBE degradation over time.

9.3.2 Load cases

A combination of the functional and environmental loads shall be designed for.

For permanently abandoned wells, the specific gravity of well fluid accounted for in the design shall as a maximum be equal to a seawater gradient, unless otherwise documented.

The following load cases apply for the abandonment design:

Table 22 – Load cases

Item	Description	Additional requirements
1.	Pressure induced by migration of formation fluid into the wellbore based on a worst anticipated reservoir pressure and lowest anticipated fluid density for the abandonment period	For permanent abandonment, increase of reservoir pressure due to a natural re-pressurization to initial/virgin level, re-development scenarios (injection) or gas storage shall be accounted for and documented. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented.
2.	Pressure testing of casing plugs	Criteria as given in EAC 24
3.	Temporary abandonment plugs: induced internal pressure by migration of formation fluid into the wellbore	Ensure the induced internal pressure is less than the burst rating of the casing (including wear) at the plug setting depth.
4.	Collapse loads from seabed subsidence or reservoir compaction	The effects of seabed subsidence above or in connection with the reservoir shall be included.
5.	Damage to primary cementation (crack forming) due to pressure test	Load cases do not include damage to primary cementation due to pressure testing.

9.3.3 Minimum design factors

The design factors for temporary abandonment shall be as described in 4.3.6.

9.3.4 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity.

Table 23 – Well control action procedures

Item	Description	Comments
1.	Cutting of casing	Fluid losses or trapped gas pressure in casing annulus
2.	(SSW) Pulling casing hanger seal assembly	Fluid losses or trapped gas pressure in casing annulus
3.	Re-entry of suspended or temporary abandoned wells	Account for trapped pressure under shear ram or under plugs due to possible failure of temporary plugs

9.3.5 Well control action drills

Well control action drills shall be performed in line with the current activity, with the frequency as described in Section 4.

9.3.6 Well control requirements

Cutting/perforating the casing and retrieving seal assemblies shall be performed with active pressure control equipment in place to prevent uncontrolled flow from annuli between casings and into the well/riser.

9.4 Suspension

9.4.1 General

Suspension is defined as a well status, where the well operation is suspended without removing the well control equipment. This applies to wells under construction or intervention.

EXAMPLE Rig skidded to do short term work on another well, strike, WOW, waiting on equipment, etc.

9.4.2 Well barrier acceptance criteria

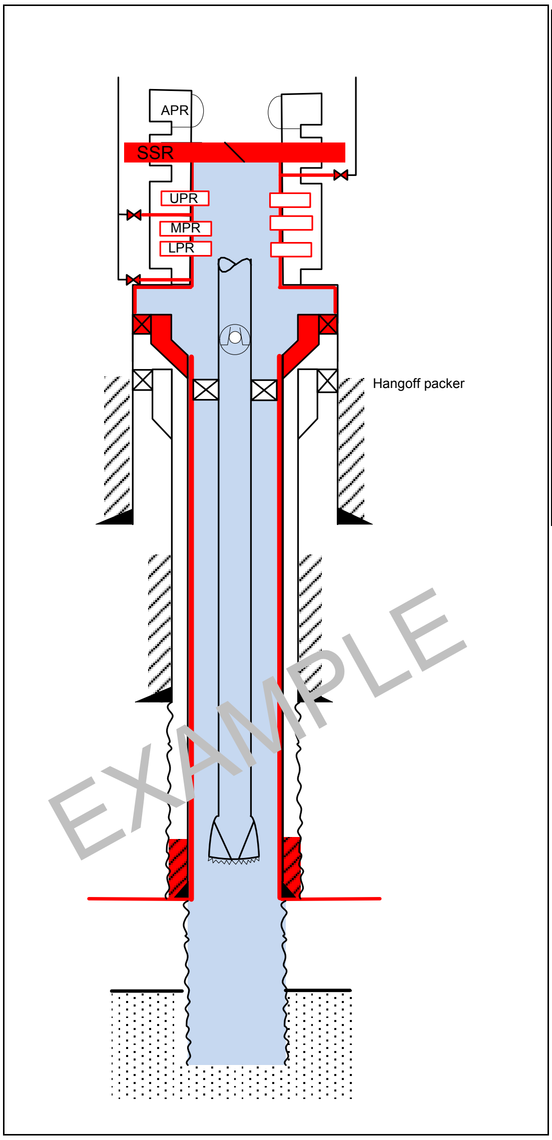
None.

9.4.3 Well barrier element acceptance criteria

Well barriers and WBE material(s) shall have sufficient integrity to meet the suspension period, including contingency.

9.4.4 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
BOP	4	

NOTE 1 Wellbore fluid shall be qualified for the duration of the hang-off period.
NOTE 2 A "drill-string valve" shall be installed in the drill pipe hang-off assembly.

Figure 9.4.5 – Suspended well, hang off/disconnect of marine riser

9.5 Temporary abandonment

9.5.1 General

Temporary abandonment is defined as:

a) temporary abandonment – with monitoring:
   Well status where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested. If the criteria cannot be fulfilled, the well shall be categorized as a temporary abandoned well without monitoring. There is no maximum abandonment period for wells with monitoring.

b) temporary abandonment – without monitoring:

   Well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested. The maximum abandonment period shall be three years.

For temporary abandoned subsea wells without monitoring, a program for visual observation shall be established. The frequency shall be substantiated by a risk assessment and shall not exceed one year.

It shall be possible to re-enter temporary abandoned wells in a safe manner for the planned duration of the temporary abandonment.

Prior to temporary abandonment, the future plans for the well and the planned duration of the abandonment period shall be documented.

9.5.2 Well barrier acceptance criteria

For temporary abandoned wells with monitoring, periodic maintenance testing and monitoring shall be performed on the WBE as per the respective EAC table.

For temporarily abandoned wells without monitoring, the WBE material(s) shall have sufficient integrity to meet the planned abandonment period.

9.5.2.1 Well barrier acceptance criteria- subsea wells

Temporarily abandoned subsea wells shall be protected from external loads in areas with fishing / trawling activities, or other seabed activities.

For completed subsea wells that are not tied back to a production facility and cannot be monitored, a yearly (ROV) inspection program shall be performed. Prior to temporary abandonment, the following requirements shall be fulfilled:

a) Production/injection packer and tubing hanger is pressure tested.
b) Tubing is pressure tested.
c) The DHSV is closed and pressure/function tested.
d) All valves in the subsea tree are pressure/function tested and are closed.
e) For wells with horizontal subsea tree, the tubing hanger crown plug(s) is pressure tested.

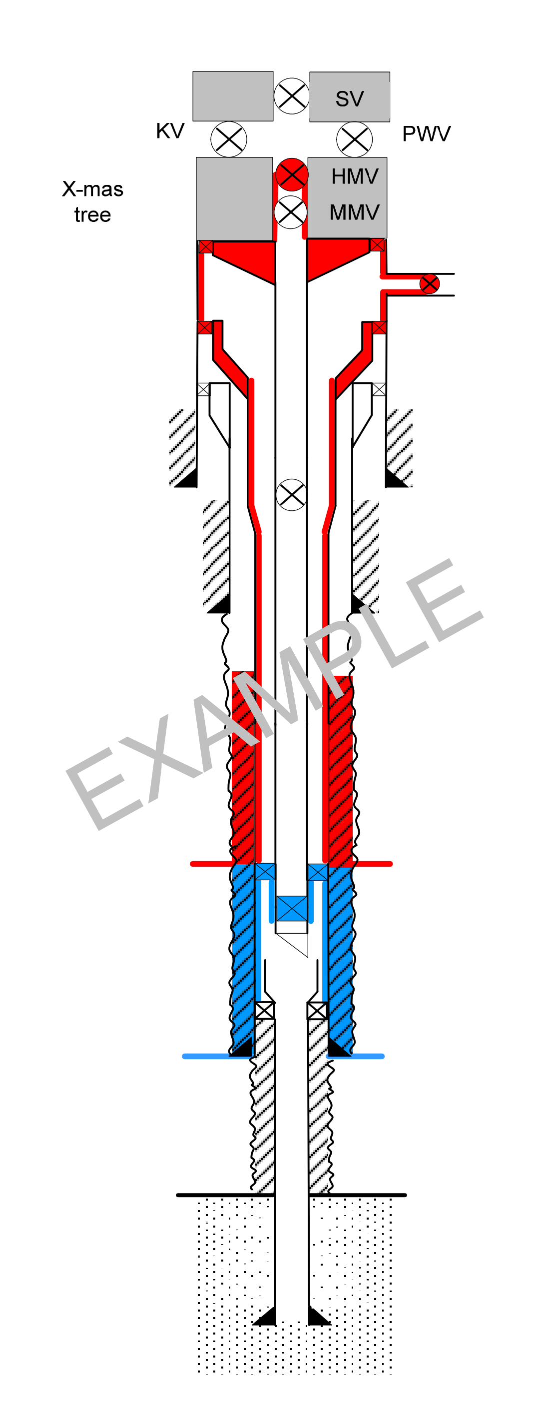
All valves shall be verified to have zero leak rate or plug(s) shall be installed to compensate for leaking valves.

9.5.3 Well barrier element acceptance criteria

There are no additional requirements to what is described in section 15.

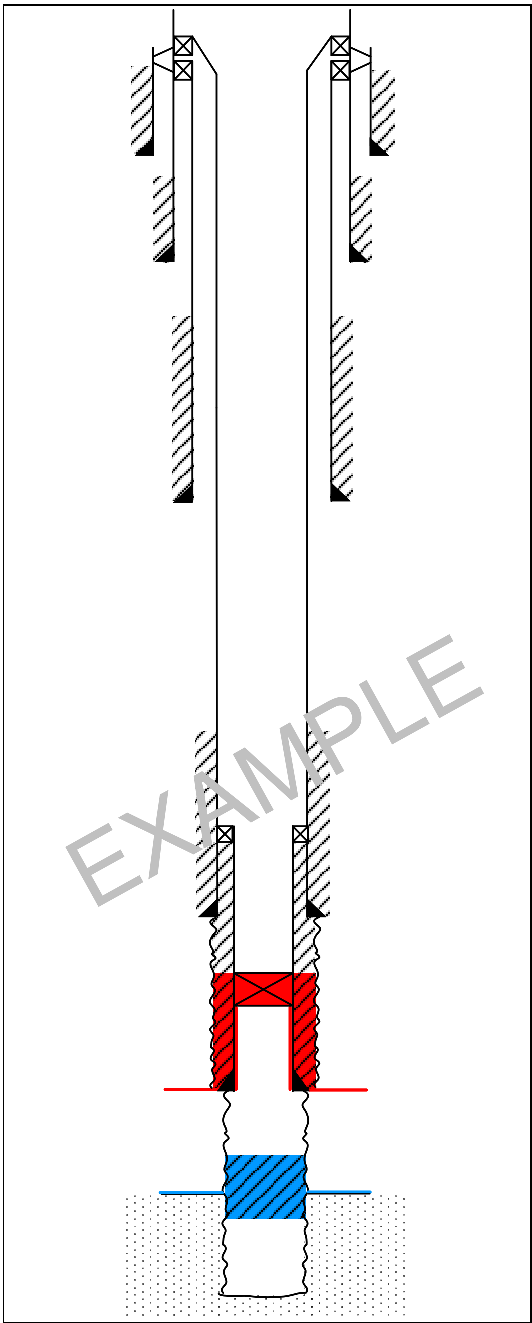
9.5.4 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (up to prod packer)	22	
Casing (up to prod packer)	2	
Production packer	7	
Deepset plug	6	
Secondary well barrier		
In-situ formation (at prod packer)	51	
Casing cement (above prod packer)	22	
Casing	2	
Casing hanger (with seal assembly)	5	
Annulus access valve	17	
Tubing hanger (with seals)	10	
Surface production tree valves/connector	31	
Surface production tree body	31	

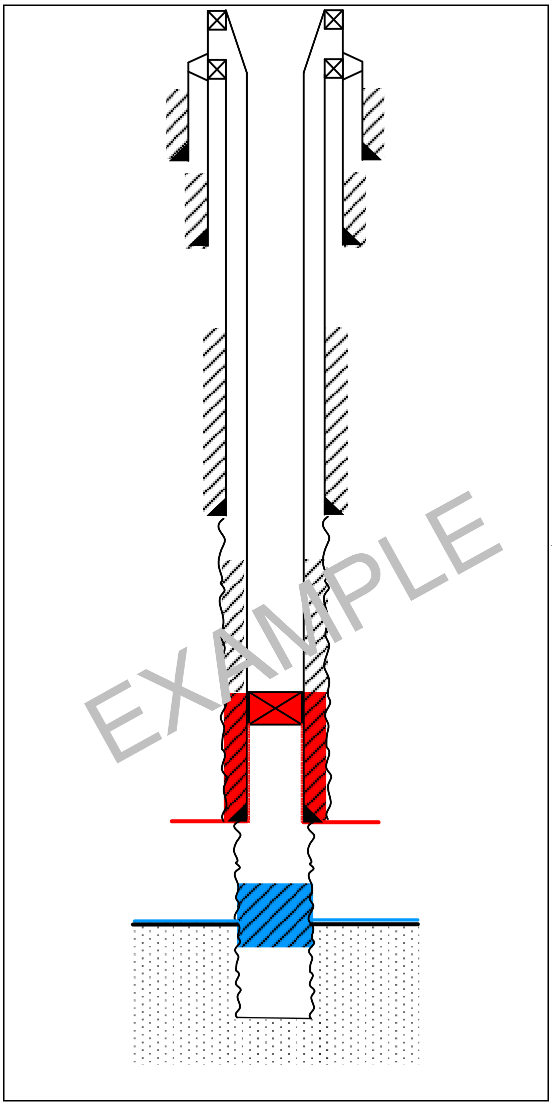
Figure 9.5.4.1 – Production well with deep set mechanical plug, continuous monitoring



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Cement plug	24	
Secondary well barrier		
In-situ formation (at shoe)	51	
Casing cement	22	
Casing	2	
Cement plug or Mechanical plug*	24 28	

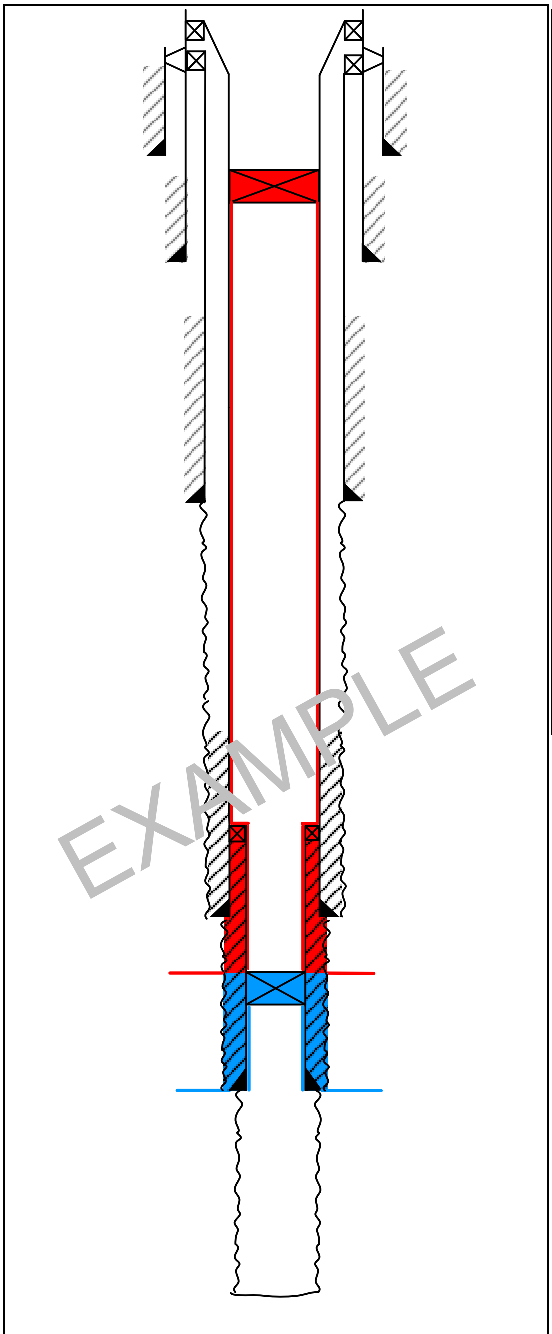
*Set at a depth where well can be re-entered safely.

Figure 9.5.4.2 – Temporary abandonment, reservoir exposed, liner



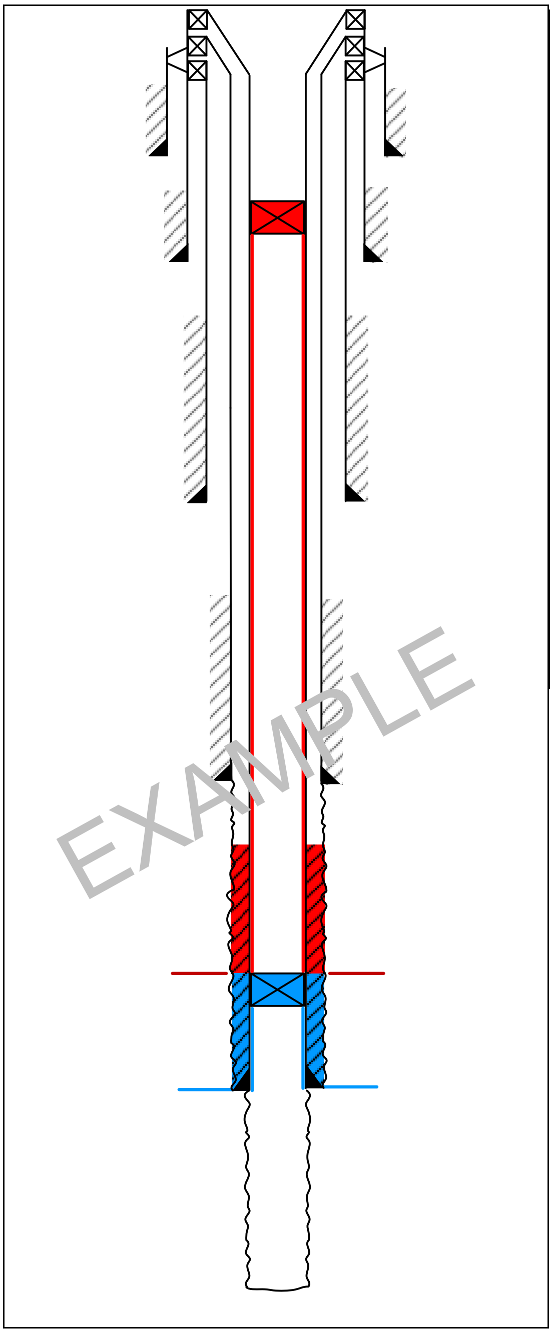
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Cement plug	24	
Secondary well barrier		
In-situ formation (at the shoe)	51	
Casing cement	22	
Casing	2	
Cement plug or Mechanical plug	24 28	

Figure 9.5.4.3 – Temporary abandonment, reservoir exposed, casing



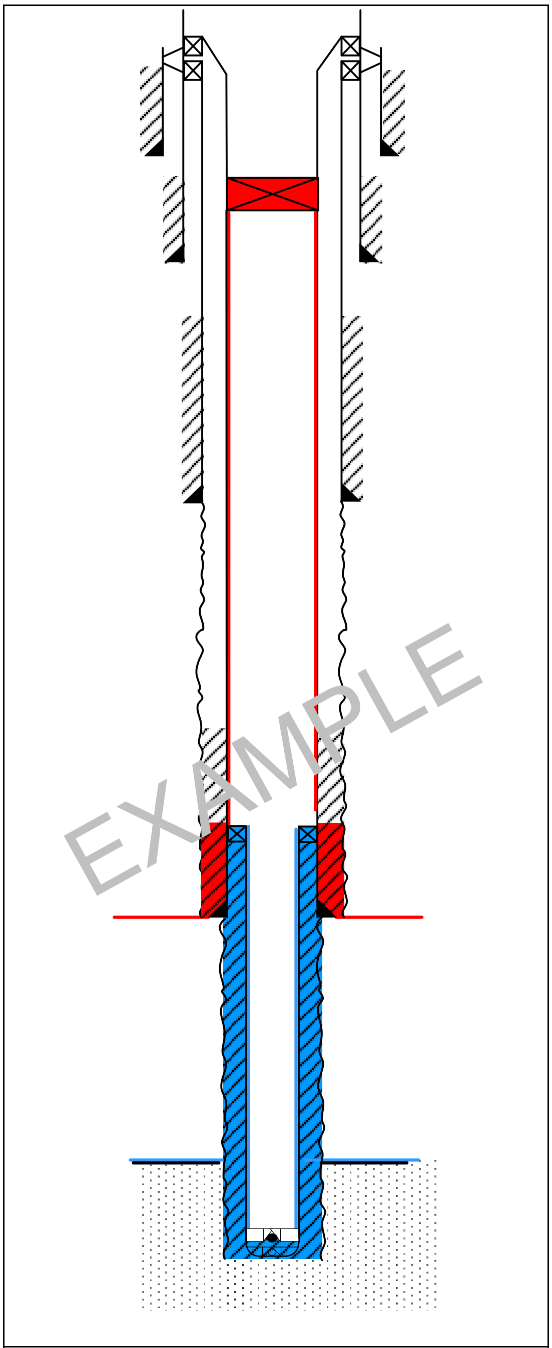
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug or mechanical plug	24 28	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Liner top packer	43	
Cement plug or mechanical plug	24 28	

Figure 9.5.4.4 – Temporary abandonment, no sources of inflow exposed, liner



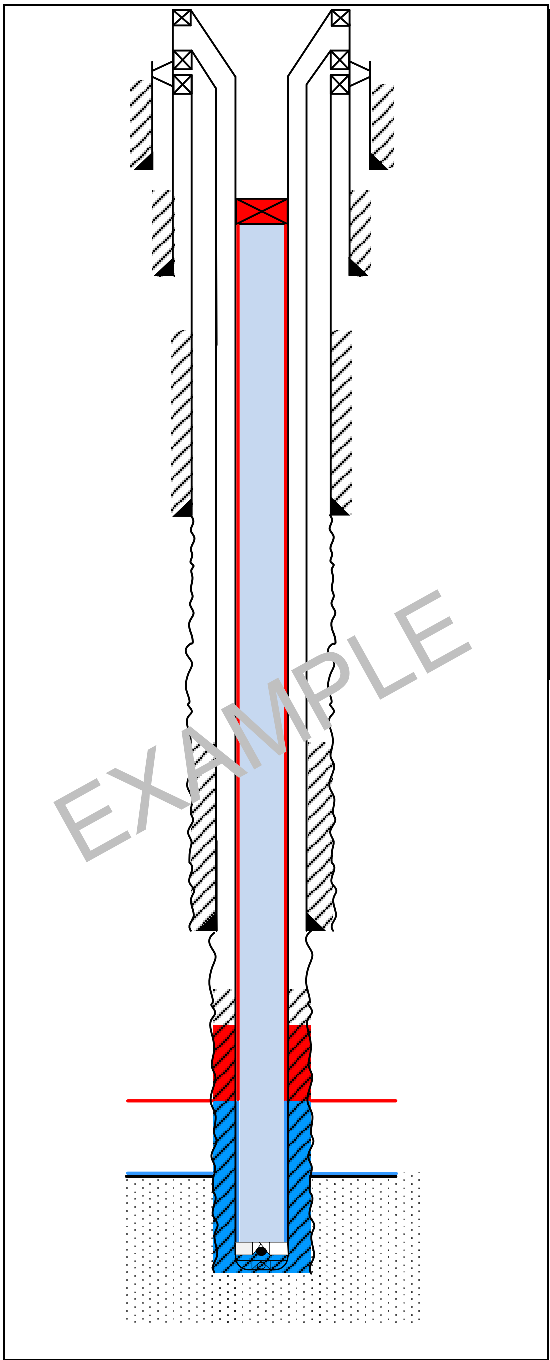
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug or mechanical plug	24 28	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug or mechanical plug	24 28	

Figure 9.5.4.5 – Temporary abandonment, no sources of inflow exposed, casing



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing float valves	41	
Casing cement	22	
Liner top packer	43	
Casing/liner	2	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug or mechanical plug	24 28	

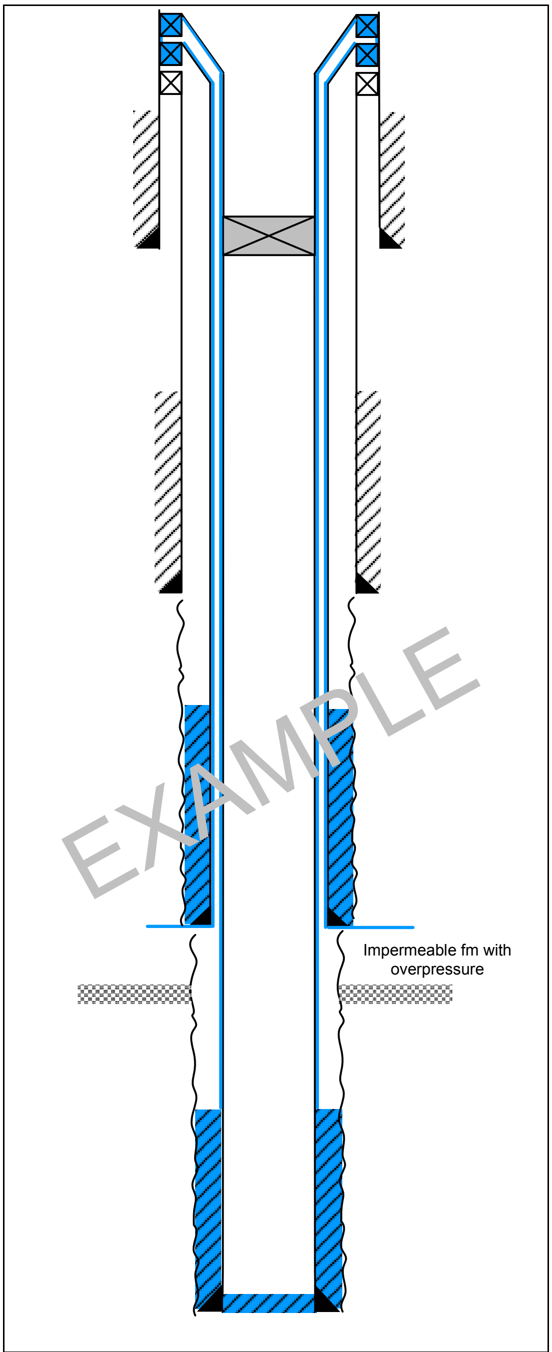
Figure 9.5.4.6 – Temporary abandonment, non-perforated well



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Casing float valves	41	
Fluid column*	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Mechanical plug	28	

*If the casing float valves are only pressure tested (not inflow tested), the well shall be secured with a fluid barrier (time limited) in addition to the shallow set plug.

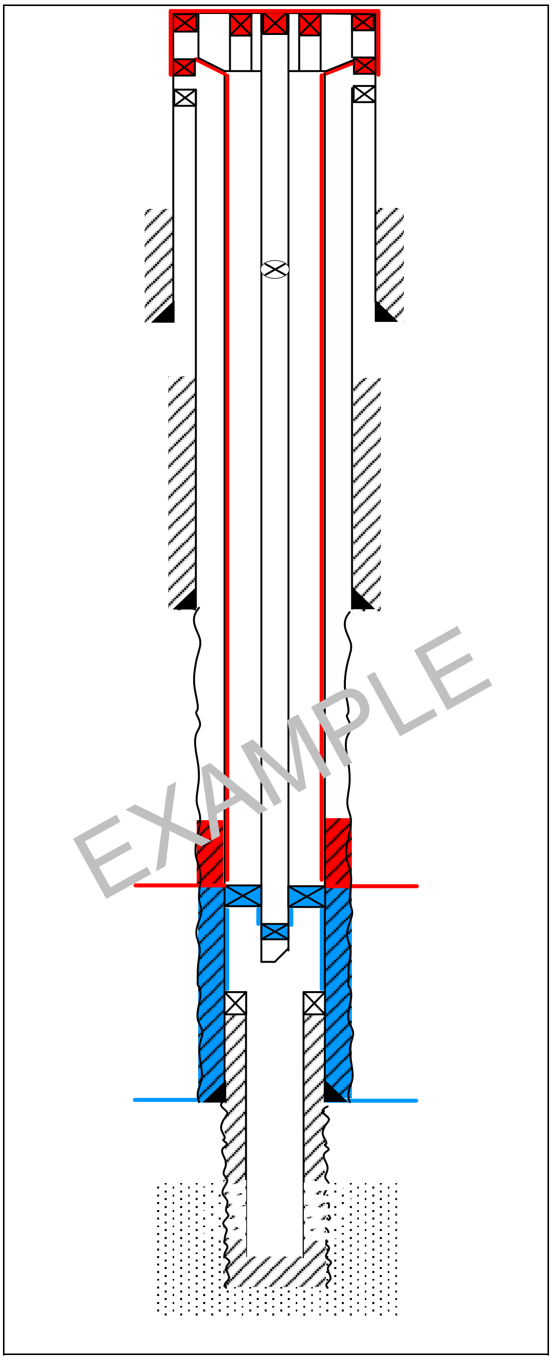
Figure 9.5.4.7 – Temporary abandonment, non-perforated well, casing



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Seal assembly	5	
Wellhead	12	
Seal assembly	5	
Casing	2	
Cement plug	24	
Casing cement	22	
Secondary well barrier		
None		

NOTE Impermeable formations with no HC shall be verified and documented.

Figure 9.5.4.8 – Temporary abandonment, impermeable formation with over pressure, non-perforated



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (up to production packer)	22	
Casing/liner (up to production packer)	2	
Production packer	7	
Completion string	25	
Deep set tubing plug	6	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing hanger	10	
Tubing hanger plug	11	

Figure 9.5.4.9 – Temporary abandonment, perforated well with BOP or XT removed

9.6 Permanent abandonment

9.6.1 General

This section covers requirements and guidelines pertaining to well integrity during permanent abandonment. Permanent abandonment is defined as a well status, where the well is abandoned and will not be used or re-entered again.

9.6.2 Well barrier acceptance criteria

Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented.

The following individual or combined well barriers/isolations shall be a result of well plugging activities:

Table 24 – Well barrier depth position

Name	Function	Depth position
Primary well barrier	To isolate a source of inflow, formation with normal pressure or over-pressured/ impermeable formation from surface/seabed.	The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below, see 4.2.3.6.7 Testing of formation.
Secondary well barrier	Back-up to the primary well barrier, against a source of inflow	As above
Crossflow well barrier	To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.	As above
Open hole to surface well barrier	To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.	No depth requirement with respect to formation integrity

The overburden formation including shallow sources of inflow shall be assessed with regards to abandonment requirements.

Multiple reservoir zones/perforations located within the same pressure regime can be regarded as one reservoir for which a primary and secondary well barrier shall be installed (see figure 9.6.2.1).

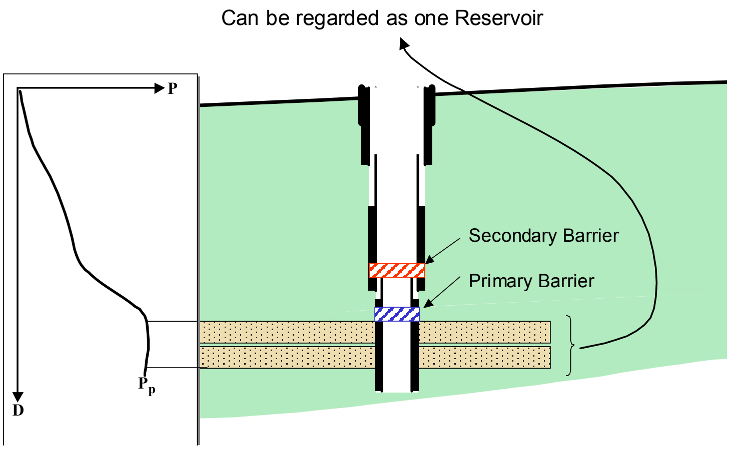


Figure 9.6.2.1 – Multiple reservoirs

A well barrier can function as a shared well barrier for more than one wellbore.

Permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally (see figure 9.6.2.2). The well barrier(s) shall be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure.

The suitability of the selected plugging materials shall be verified and documented. Degradation of the casing should be considered.

Removal of downhole equipment is required when this can cause loss of well integrity. Control lines and cables shall not form part of the permanent well barriers.

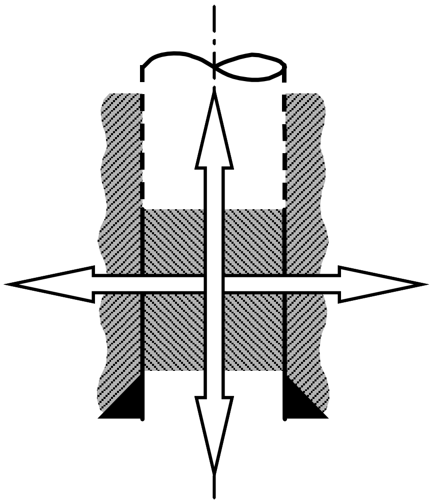


Figure 9.6.2.2

A permanent well barrier should have the following characteristics:

a) provide long term integrity (eternal perspective);
b) impermeable;
c) non-shrinking;
d) able to withstand mechanical loads/impact;
e) resistant to chemicals/ substances (H_2S, CO_2 and hydrocarbons);
f) ensure bonding to steel;
g) not harmful to the steel tubulars integrity.

9.6.2.1 Sidetracking

The original wellbore should be permanently abandoned prior to a sidetrack / slot recovery. If permanent abandonment is not feasible at the time of sidetrack, the well barrier(s) shall be established when the slot is permanently abandoned.

9.6.3 Well barrier element acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 25 – Additional EAC requirements

Table no.	Element name	Additional features, requirements and guidelines
2	Casing	Steel tubulars WBE shall be supported by cement or alternative plugging materials.
22	Casing cement	Cement in the liner lap or in tubing annulus can be accepted as a permanent WBE when the liner is centralized in the overlap section. The casing cement in the liner lap shall be logged.
51	In-situ formation	The in-situ formation (e.g. shale, salt) shall be impermeable and have sufficient formation integrity.

Elastomer sealing components in WBE's are not acceptable for permanent abandonment.

When completion tubulars are left in the well and WBE are installed in the tubing and annulus, the position and integrity of these shall be verified:

a) The casing cement between the casing and tubing shall be verified by pressure testing.
b) The cement plug (inside tubing) shall be tagged and pressure tested.

9.6.3.1 External WBE

The external WBE (e.g. casing cement) shall be verified to ensure a vertical and horizontal seal.

The requirement for an external WBE is 50 m with formation integrity at the base of the interval.

If the casing cement is verified by logging, a minimum of 30 m interval with acceptable bonding is required to act as a permanent external WBE.

The interval shall have formation integrity.

Logging of casing cement shall be performed for critical cement jobs and for permanent abandonment where the same casing cement is a part of the primary and secondary well barriers.

If sustained casing pressure is observed, the seal of the casing cement shall be re-verified.

9.6.3.2 Internal WBE

An internal WBE (e.g. cement plug) shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and shall be minimum 50 m if set on a mechanical plug/cement as a foundation, otherwise according to EAC 24.

9.6.4 Removing equipment above seabed

For permanent abandonment wells, the wellhead and casings shall be removed below the seabed at a depth which ensures no stick up in the future.

Required cutting depth shall be sufficient to prevent conflict with other marine activities. Local conditions such as soil and seabed scouring due to sea current should be considered. For deep water wells it may be acceptable to leave or cover the wellhead/structure.

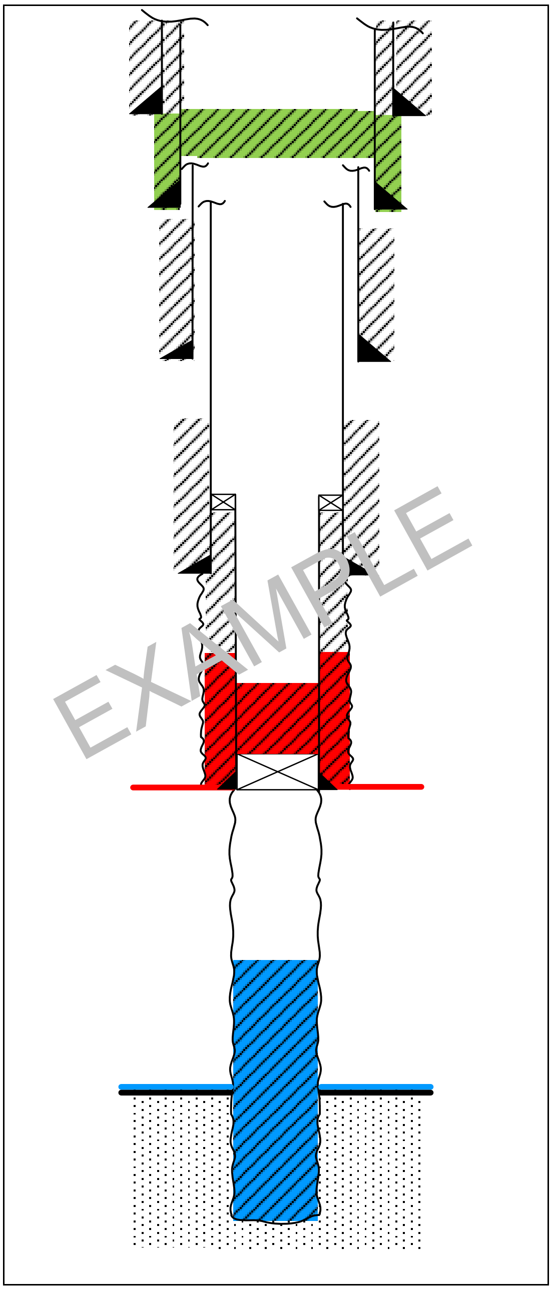
Mechanical or abrasive cutting is the preferred method for removal of the casing/conductor at seabed

The use of explosives to cut casing / conductor is acceptable if the risk to the surrounding environment is at the same level as other means of cutting (Example: directed / shaped charges providing upward and downward protection).

The location shall be inspected to ensure no other obstructions related to the drilling and well activities are left behind on the sea floor.

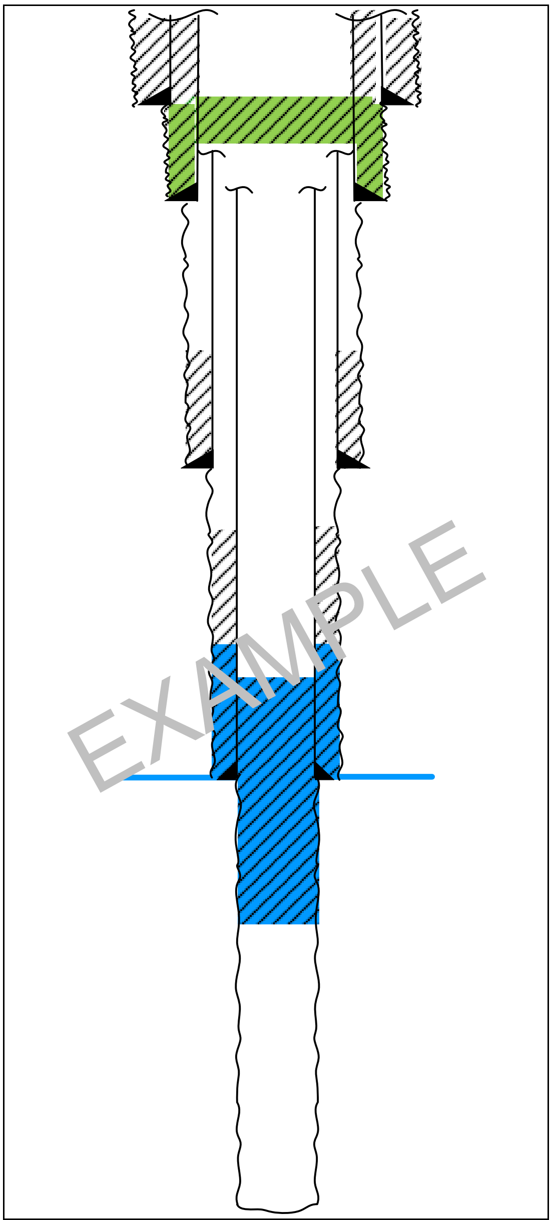
9.6.5 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



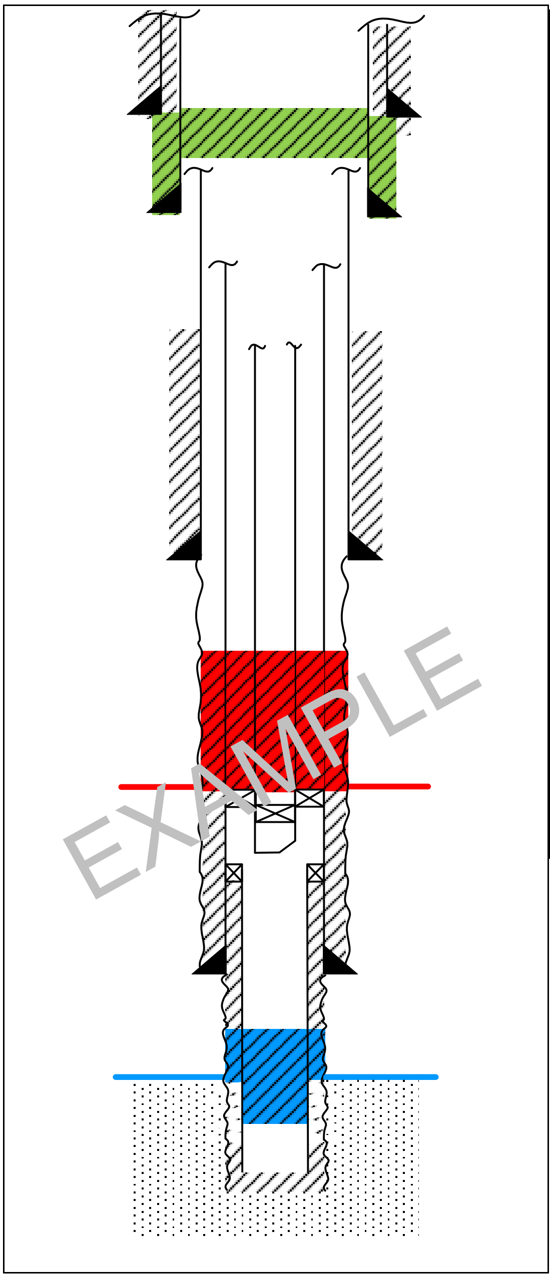
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Cement plug	24	
Secondary well barrier		
Formation in-situ	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

Figure 9.6.5.1 – Permanent abandonment, open hole



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Casing	2	
Casing cement	22	
Cement plug	24	

Figure 9.6.5.2 – Permanent abandonment, open hole, casing. No source of inflow

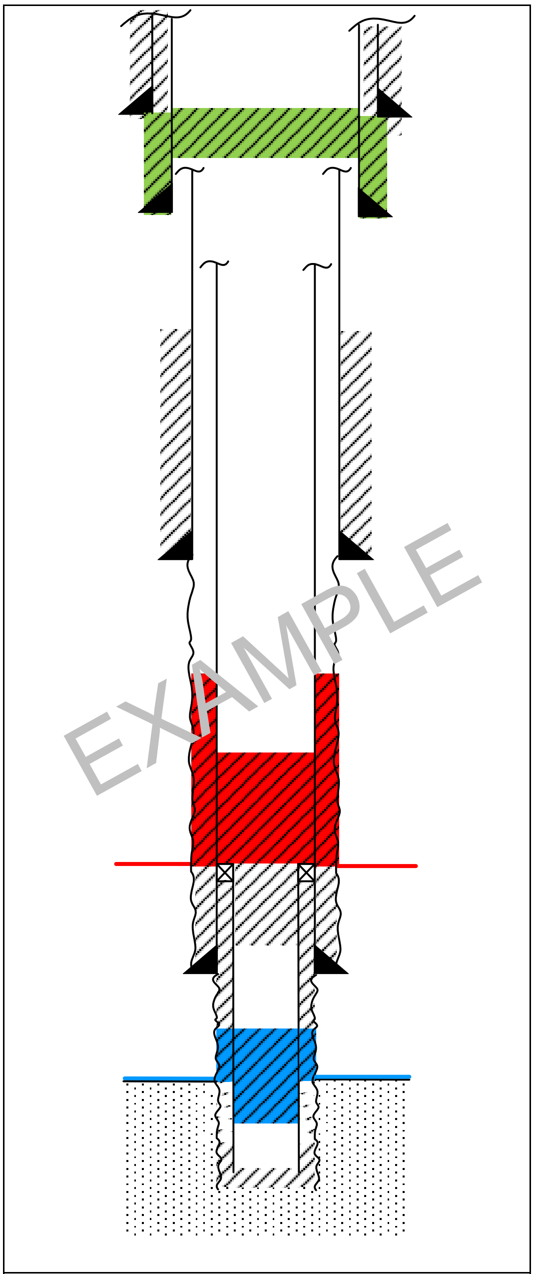


Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Liner cement	22	
Casing	2	
Cement plug	24	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing cement (between casing and tubing)	22	
Cement plug*	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

*Inside tubing.

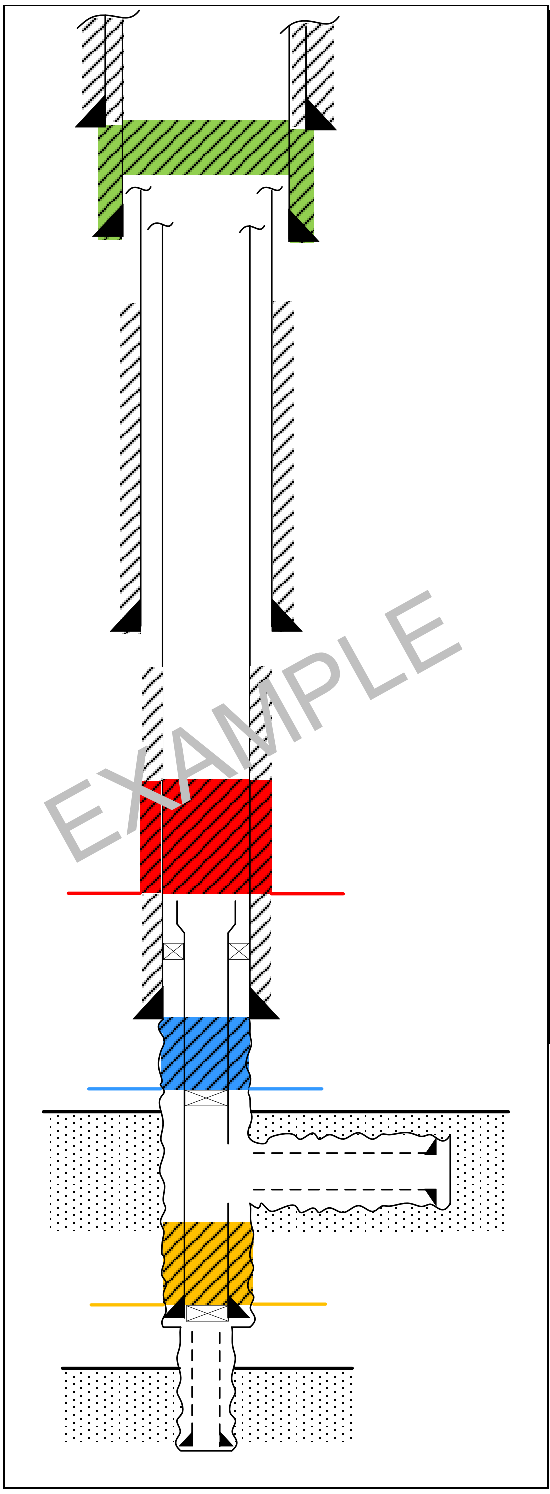
NOTE Tubing is centralized.

Figure 9.6.5.3 – Permanent abandonment, perforated well, tubing left in hole



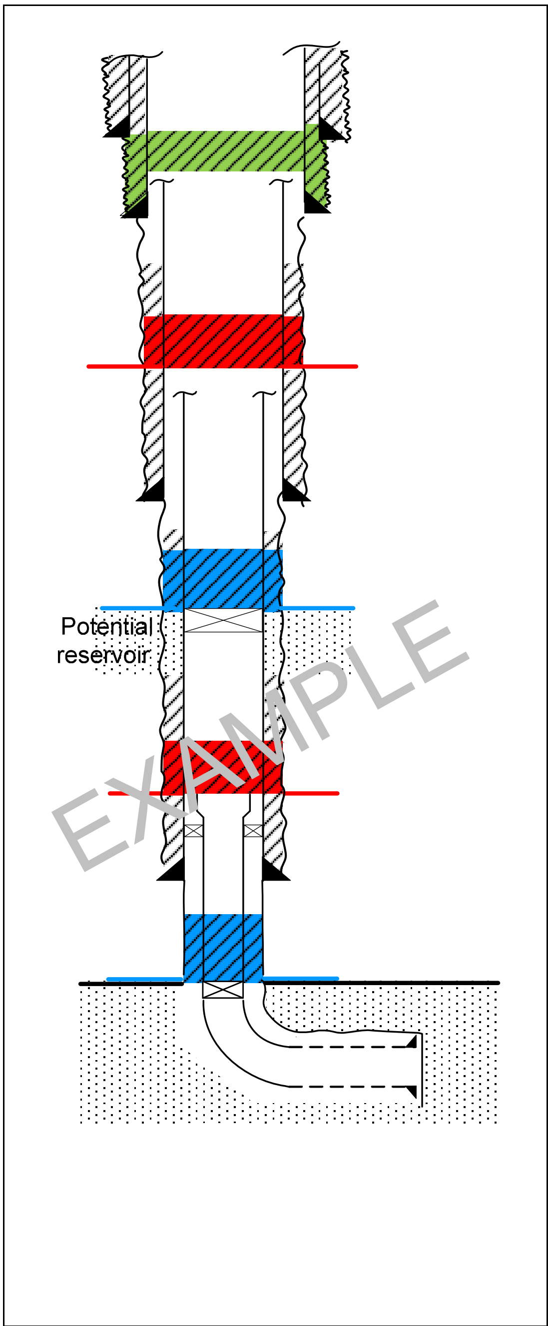
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing	2	
Cement plug	24	
Secondary well barrier		
Formation in-situ	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Cement plug	24	
Casing cement	22	

Figure 9.6.5.4 – Permanent abandonment, perforated well, tubing removed



Well barrier elements	EAC table	Verification/monitoring
Crossflow well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Cement plug	24	
Casing cement	22	

Figure 9.6.5.5 – Permanent abandonment, multi bore with slotted liners or sand screens



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Primary well barrier (potential reservoir)		
In-situ formation	51	
Cement plug	24	
Casing	2	
Casing cement	22	
Secondary well barrier (potential reservoir)		
In-situ formation	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

Figure 9.6.5.6 – Permanent abandonment, slotted liner in multiple reservoirs

9.6.6 Examples for different permanent abandonment options

The following illustrations show various permanent abandonment options.

9.6.6.1 Abandonment of open hole with cement plugs

The last open hole section of a wellbore is abandoned permanently by setting an open hole cement plug across/above the reservoir and with an additional cement plug from the open hole into the casing.

The requirement is to have sufficient formation integrity at the base of both well barriers.

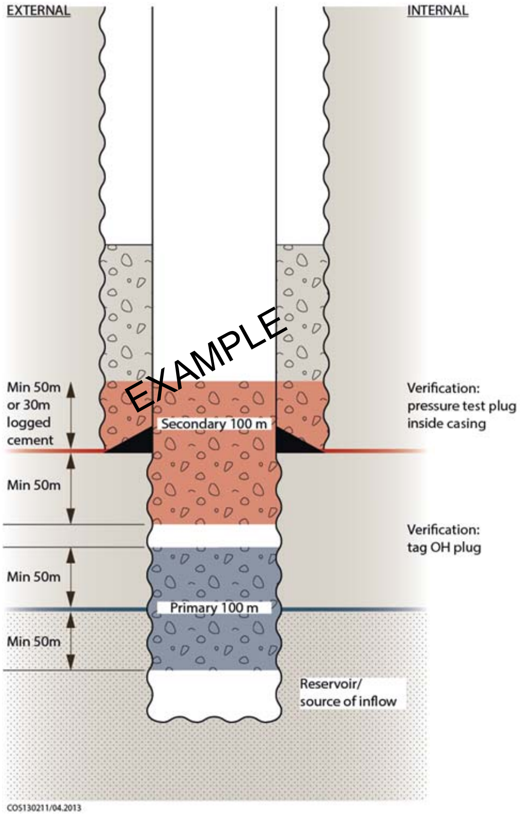


Figure 9.6.6.1 – Permanent abandonment, open hole and inside casing plugs

9.6.6.2 Back-to-back cement plugs and logged casing cement

The last open hole section of a wellbore or a perforated casing/liner is abandoned permanently by setting two back to back cement plugs from the reservoir (or as close as possible to the reservoir), provided that the casing cement is verified in the annulus.

The internal cement plug length covers the logged interval in the annulus.

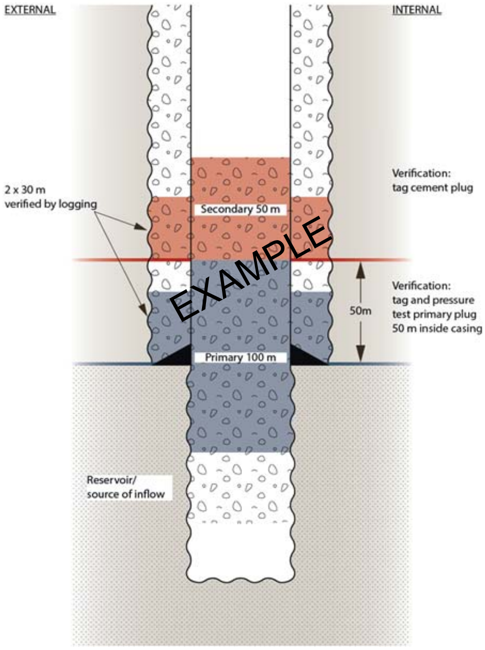


Figure 9.6.6.2 – Permanent abandonment, two back to back cement plugs

9.6.6.3 Single cement plug in combination with mechanical plug

A wellbore can be abandoned permanently by setting a mechanical plug to serve as a foundation for a single cement plug. The internal cement plug length covers the logged interval in the annulus.

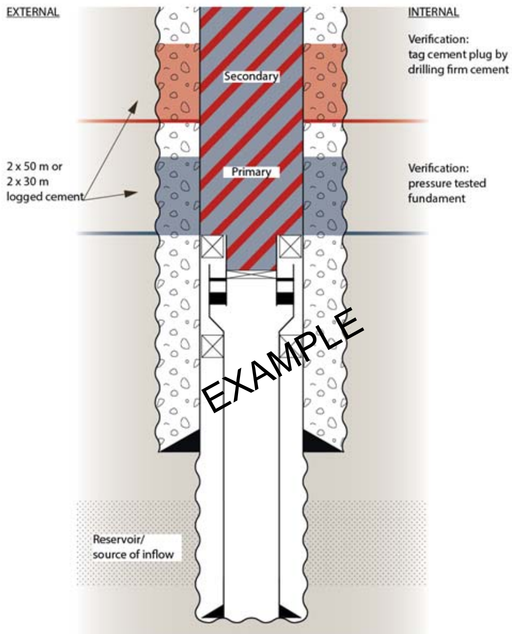


Figure 9.6.6.3 – Permanent abandonment, single cement plug with mechanical plug foundation

9.6.6.4 Tubing stump left in hole

The last section of a wellbore or a perforated casing/liner is abandoned permanently by setting a primary cement plug above the reservoir (or as close as possible to the reservoir) and the secondary cement plug within the tubing and tubing annulus.

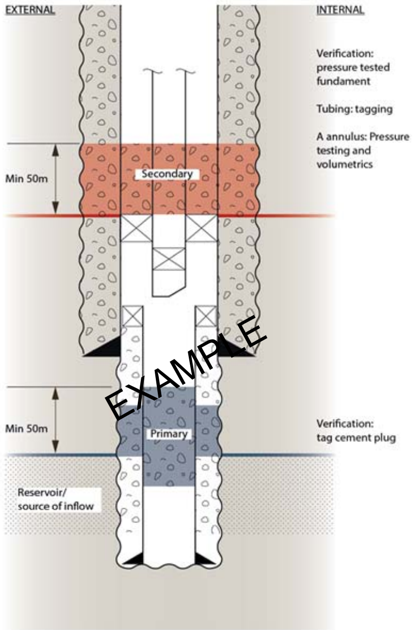


Figure 9.6.6.4 – Permanent abandonment, with tubing stump left in hole

9.6.7 Section milling to establish a cement plug

The following example can be applied when section milling is required to establish well barriers.

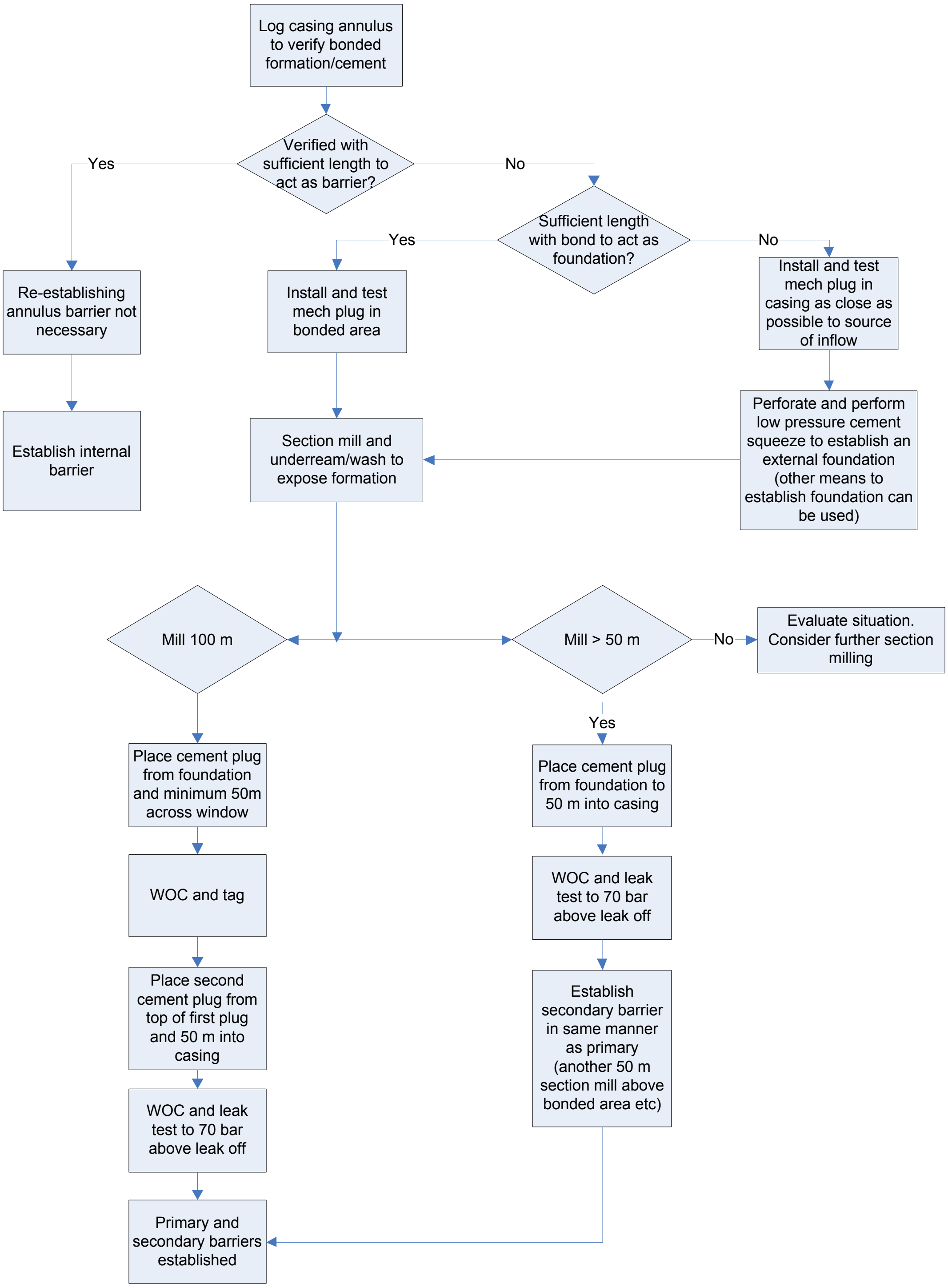


Figure 9.6.7.1 – Section milling to establish a cement plug

9.6.8 Section milling examples

For wells with poor casing cement or no access to the last open hole section, section milling (removal of casing) is an alternative method for placing cement in contact with formation to form permanent well barriers.

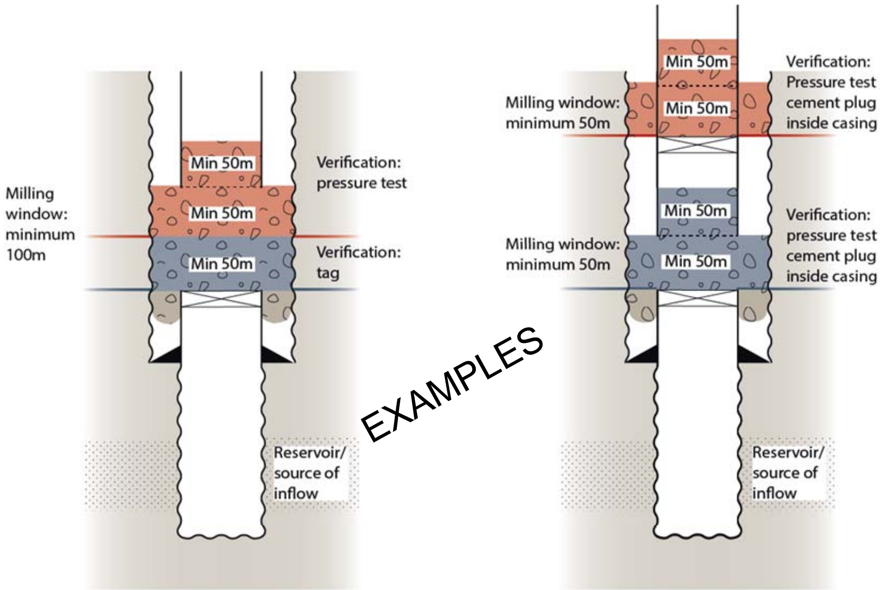


Figure 9.6.8.1 – Permanent abandonment, section milling

9.6.9 Alternative method to establish a permanent well barrier

For wells with poor casing cement or no access to the last open hole section, the following example can be applied to place cement in contact with formation to form permanent well barriers. This is an alternative to section milling.

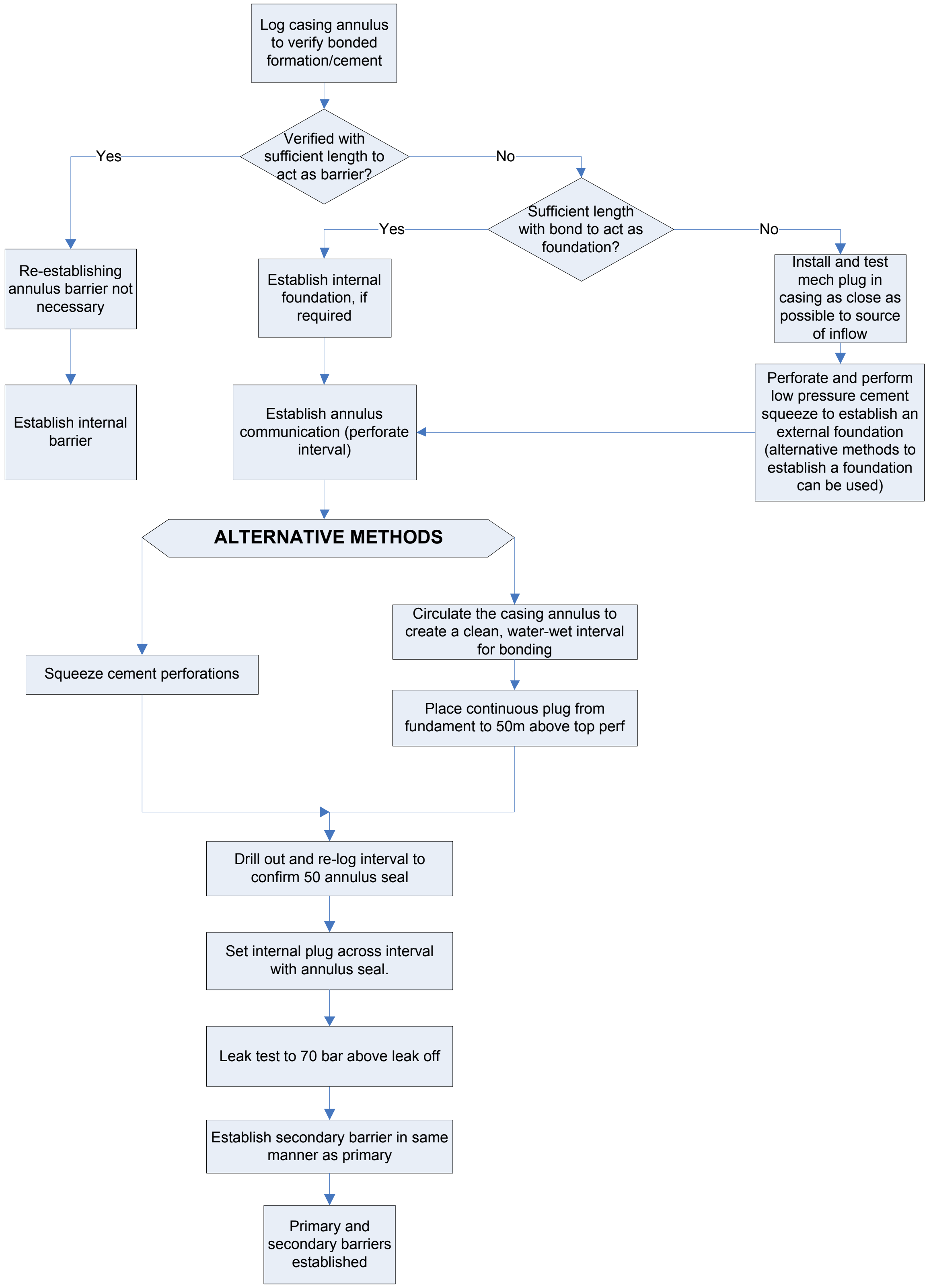


Figure 9.6.9.1 – Alternative method to establish a permanent well barrier

The figure below describes the placement of the well barriers using the alternative method.

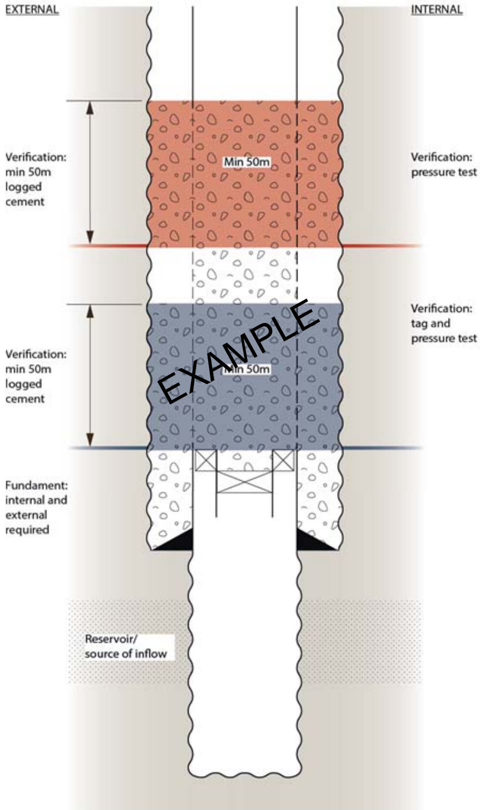


Figure 9.6.9.1 – Permanent abandonment, alternative method

9.7 Other topics

9.7.1 Risks

Design and operational risks shall be assessed. Typical risks could include:

a) pressure and formation integrity uncertainties;
b) time effects:
   1. long term development of reservoir pressure;
   2. deterioration of materials used;
   3. sagging of weight materials in well fluids.
c) scale in production tubing;
d) H_2S or CO_2;
e) release of trapped pressure;
f) unknown status of equipment or materials;
g) environmental issues.

9.7.2 Vertical XT removal

The table below describes well barrier requirements when removing a VXT.

Table 26 – Vertical XT removal

Fluid	Possible to monitor primary well barrier?	Primary WBE	Secondary WBE	Compensating measures
Light fluid (under-balanced)	Yes (downhole pressure gauge or tubing to annulus communication)	Deep set mechanical bridge plug	Inflow tested DHSV and drop protection device – accepted if DHSV has zero leakage, or a BPV/tubing hanger plug, or a shallow set mechanical bridge plug	Status of primary well barrier to be monitored at all times on DHPG or A-annulus pressure
	No	Deep set mechanical bridge plug	a BPV/tubing hanger plug, or a shallow set mechanical bridge plug	Inflow tested DHSV as compensating measure due to not able to monitor primary barrier
Heavy fluid (over-balanced)	Yes (tubing to annulus communication)	Deep set mechanical bridge plug and brine/mud above plug, or Kill pill and brine or kill mud from perforations/screen to surface	Inflow tested DHSV and drop protection device – accepted if DHSV has zero leakage, or a BPV/tubing hanger plug, or a shallow set mechanical bridge plug	Fluid level or applied pressure to be monitored on A-annulus
	No	Deep set mechanical bridge plug and brine/mud above plug	Inflow tested DHSV and drop protection device – accepted if DHSV has zero leakage, or a BPV/tubing hanger plug, or a shallow set mechanical bridge plug	
	No	Kill pill and brine or kill mud from perforations/screen to surface	a BPV/tubing hanger plug, or a shallow set mechanical bridge plug	Inflow tested DHSV as compensating measure due to not able to monitor primary well barrier

9.7.3 Horizontal XT removal

A deep set plug shall be installed when removing a horizontal XT.

The production tubing and A-annulus shall be displaced to kill fluid. Specific gravity of the kill fluid shall give an overbalance with a safety margin at plug depth, prior to pulling the production tubing.

When the tubing is removed, a shallow plug shall be installed in production casing prior to removal of the XT.

10 Wireline operations

10.1 General

This section covers requirements and guidelines pertaining to well integrity in wireline (WL) operations. A wireline operation is a technique for deployment of various electrical or mechanical downhole tools (logging tools, plugs, packers, perforating guns, shifting tools, pulling tools etc.) on electrical cables, braided cables or slickline. The operations are performed in pressurised wells or in dead wells.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

10.2 Well barrier schematics

WBSs shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (10.7).

10.3 Well barrier acceptance criteria

The following defines specific requirements and guidelines for well barriers:

10.3.1 Well control equipment configuration

The following basic well control equipment configurations should be used. Additional elements (e.g. additional ram functions) can be considered based on each operation specific risk analysis.

a) For operations in a surface completed well:
   1. pressure control head – including a device that will automatically seal off the wellbore in the event the wireline breaks and is ejected from the wellbore:
      i. for slickline – a stuffing box;
      ii. for braided or electric cable – a grease injection head.
   2. lubricator;
   3. wireline rams:
      i. for slickline – a slickline ram;
      ii. for braided or electric cable – dual rams sealing in opposite directions with grease injection between rams.
   4. shear/seal function (safety head);
   5. riser and crossovers as required.

b) For operations with a riserless lubricator system on a subsea completed well:
   1. pressure control head (flow tubes/stuffing box);
   2. dual pack-off assembly;
   3. tool catcher (or tool trap);
   4. cutting/sealing ram or valve for wireline;
   5. lubricator;
   6. upper and lower isolation valves;
   7. safety head (shear/seal ram);
   8. connectors.

10.3.2 Deployment of tool strings

Deployment of long wireline tool strings in excess of the available surface lubrication length:

a) Use of deployment bar and deployment rams (see WBS examples for one possible configuration):

1. A double block principle (e.g. by use of two separate rams) shall be applied for sealing around the deployment bar.
2. The shear/seal function shall be qualified to shear and seal on the deployment bar (in addition to standard wireline shear/seal capabilities).

b) Use of a downhole lubricator valve (ball type) above (and in addition to) the DHSV:
1. The production tubing above the lubricator valve shall be displaced to an inert fluid
2. The DHSV shall be closed and tested in the direction of flow potential
3. The lubricator valve shall be closed and tested from above to the shut-in wellhead pressure + 70 bar.

c) Use of the DHSV with a drop protection function for the DHSV:
1. The production tubing above the DHSV shall be displaced to an inert fluid;
2. Crosshead circulation via a trip tank shall be in place to monitor the volume in the production tubing above the DHSV;
3. The DHSV shall be closed and tested in the direction of flow potential;
4. The BHA shall be handled with a quick release drop table to allow it to be dropped below the tree at any time.

10.3.3 Operational

For wireline operations the safety head is defined as the qualified shear/seal closure device, in the surface well control equipment configuration, closest to the well. It is the upper closure device in the secondary well barrier.

a) If the HMV has documented cutting and sealing capability on the workstring then it should be designated as the safety head for the purpose of well barrier definitions. There shall always be a shear/seal function in the well control stack above the tree.
b) The number of riser/lubricator connections, and the distance, between the surface tree and the safety head are critical and should be kept to a minimum (in cases where the HMV is not designated as the safety head).
c) All tools or components that the safety head may not be able to cut shall be identified prior to start of operation. Contingency procedures and compensating measures shall be in place for how to act when such tools or components are positioned across the safety head (see 10.4.1 and 10.4.2).
d) Both the LMV and HMV shall be closed and tested prior to rigging up on a well where the primary well barrier (DHSV) has failed. The shear/seal function closest to the tree shall be installed and tested prior to continuing rig up of the remaining wireline well control equipment.
e) A double-valve kill inlet connection shall be included in the rig-up. The kill line itself is not required to be rigged up. The inner valve shall be flanged. The tree kill wing valve may be used as the inner valve. Both valves shall be leak tested in the direction of flow.
f) The shear/seal ram in the lower riser package is defined as the upper closure device in the secondary well barrier when running wireline in completed subsea wells. The same minimum requirements therefore apply to the lower riser package shear/seal ram as to the wireline safety head.
g) The shear/seal ram in the subsea drilling BOP is defined as the upper closure device in the secondary well barrier when a subsea drilling BOP is installed when running wireline in sub-sea wells. The same minimum requirements therefore apply to the drilling BOP shear/seal ram as to the wireline safety head.

10.4 Well barrier elements acceptance criteria

10.4.1 Potential for compromised WBE – probability reducing measures

Certain wireline operations represent a higher than normal probability of getting stuck with non-shearable components across WBEs or near surface and/or with increased risk of cut cable not falling below the tree valves, for example running and retrieving of large OD / close tolerance plugs and valves (such as wireline retrievable insert safety valves), milling of scale deposits close to surface, etc.

For these types of operations there shall be a specific focus in the operational risk analysis and specific measures should be implemented to reduce the probability of getting stuck in critical areas of the well and/or surface well control system. Some potential measures and situation that should be evaluated include:

a) Prior to running and retrieving of close tolerance assemblies the internal diameter of the entire well control stack and wellbore, above the setting/retrieving point in the well, should be physically verified by means of a drift and/or calliper run.
b) Prior to running any close tolerance assemblies the maximum diameter(s) on the assembly should be physically verified.
c) Prior to retrieving any close tolerance assemblies from the well all diameters, lengths, shoulders, etc. should be identified and verified by means of technical documentation records. Any potential increase in OD from original design (e.g. due to deformation or swelling) should be identified and included in the risk analysis for the operation.
d) When retrieving (or running) close tolerance assemblies any indications of unexpected drag forces should be evaluated immediately from a risk perspective prior to entering critical areas in the well/rig-up.
e) The potential for a tool(s) to block the wellbore and thereby compromise well killing operations should be evaluated.

10.4.2 Potential for compromised WBE – consequence reducing measures

Where the residual risk is still considered to be unacceptably high measures should be implemented to mitigate the consequences in the event of becoming stuck with the toolstring. Mitigating measures that should be evaluated are:

a) inclusion of programmable disconnects in the toolstring to allow disconnect and closure of WBE in the event of becoming stuck;
b) inclusion or verification of shearable sections at strategic positions in the toolstring;
c) inclusion of additional closure devices in the well control configuration (e.g. an additional shear/seal ram higher up in the configuration);
d) use of flanged connections below the safety head (e.g. to provide enhanced integrity in cases where cut cable may not drop below the tree valves);
e) well kill equipment and materials to be available and/or rigged up for immediate availability.

10.5 Well control action procedures and drills

10.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 27 – Well control action procedures

Item	Description	Comments
1.	Loss of power air/electricity supply during operation	Fixed and floating installation
2.	Loss of winch power or mechanical failure	Fixed and floating installation
3.	External leak in lubricator/tool catcher	Fixed and floating installation
4.	External leak in WL BOP body	Fixed and floating installation
5.	External leak below WL BOP shear/seal function	Fixed and floating installation
6.	Broken cable blown out of well	Fixed and floating installation
7.	Leak in stuffing box/grease head	Fixed and floating installation
8.	Leak in BOP wireline ram(s)	Fixed and floating installation
9.	Leak in shear/seal	Fixed and floating installation
10.	Leak in the surface tree hydraulic master valve while lubricating against swab valve	Fixed installation
11.	Leak in lubricator valve while lubricating against lubricator valve	Floating installation
12.	Leak in test string below sub-surface test tree	Floating installation
13.	External leak in landing string	Floating installation
14.	External leak in riser above or below lower riser package	Floating installation
15.	Controlled disconnect	Floating installation
16.	Emergency disconnect	Floating installation
17.	Emergency situation on rig/platform	Fixed and floating installation
18.	Influx in well during logging on wireline	Logging without pressure control equipment on fixed and floating installation
19.	Influx in well during wireline pipe conveyed logging with side entry sub above drilling BOP	Logging without pressure control equipment on fixed and floating installation
20.	Influx in well during wireline pipe conveyed logging with side entry sub below drilling BOP	Logging without pressure control equipment on fixed and floating installation
21.	H_2S gas in work area	Fixed and floating installation

10.5.2 Well control action drills

Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts.

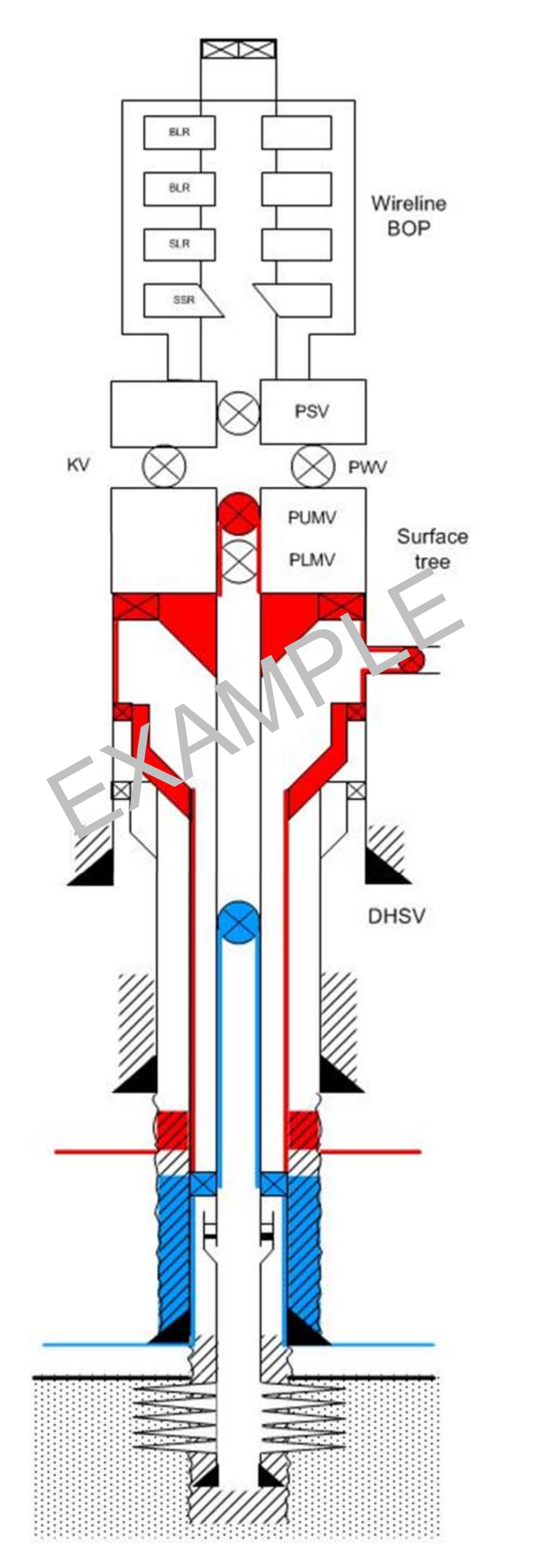
10.6 Other topics

10.6.1 Hydrate prevention

A hydrate-inhibiting fluid shall be used when there is a risk for forming of hydrates.

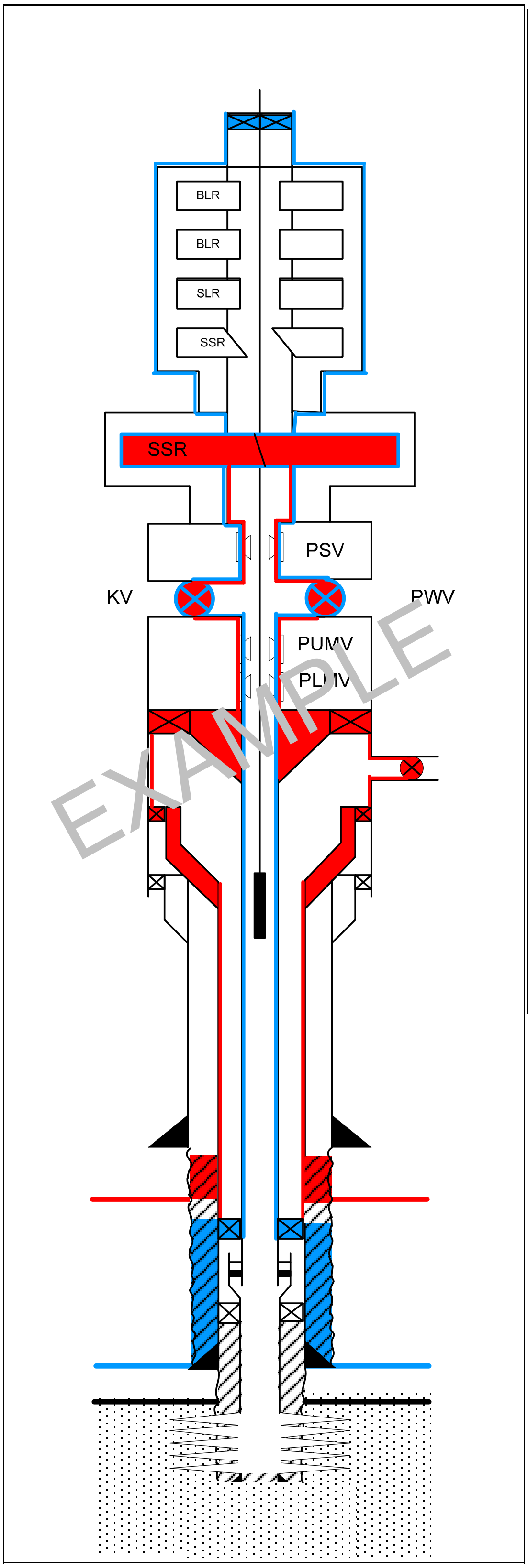
10.7 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production packer	7	
Completion string	25	
DHSV	8	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Wellhead annulus access valve	11	
Tubing hanger	10	
Surface tree	33	

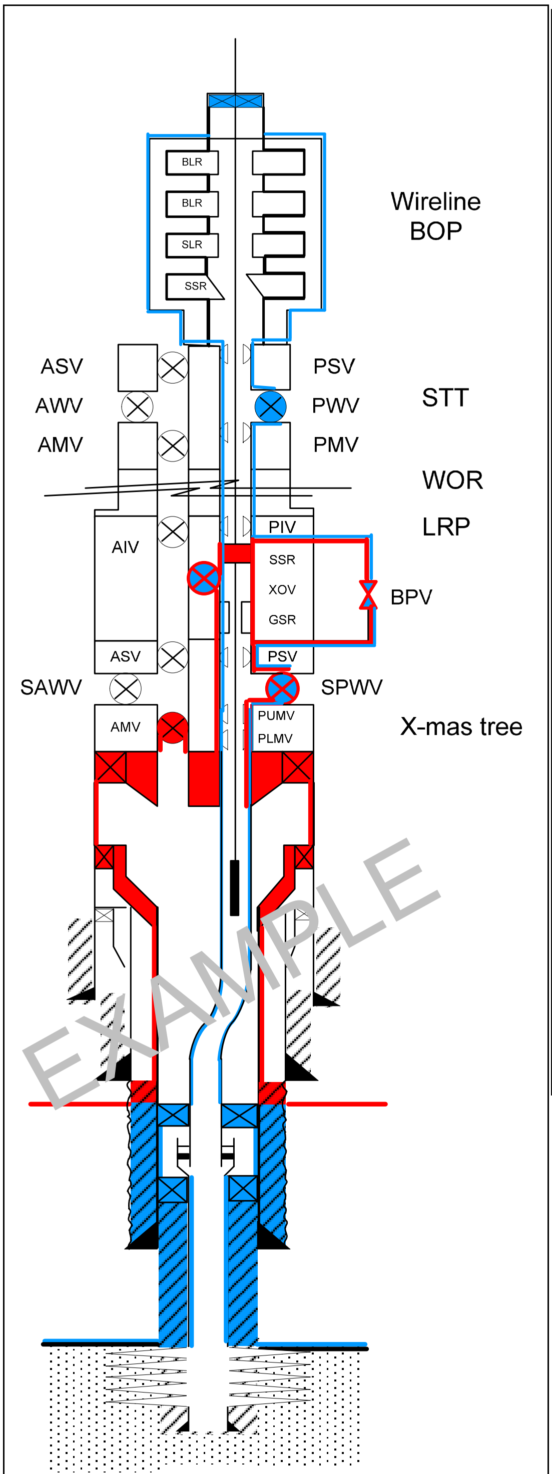
Figure 10.7.1 – Rigging wireline equipment above surface tree



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production Packer	7	
Completion string	25	
Tubing hanger	10	
Surface tree*	33	
Wireline shear/seal (safety head) - body	38	
Wireline lubricator	44	
Wireline BOP	37	
Wireline stuffing box / grease injection head	39	
Secondary well barrier		
Formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing Hanger	10	
Surface tree*	33	
Wireline shear/seal (safety head)	38	

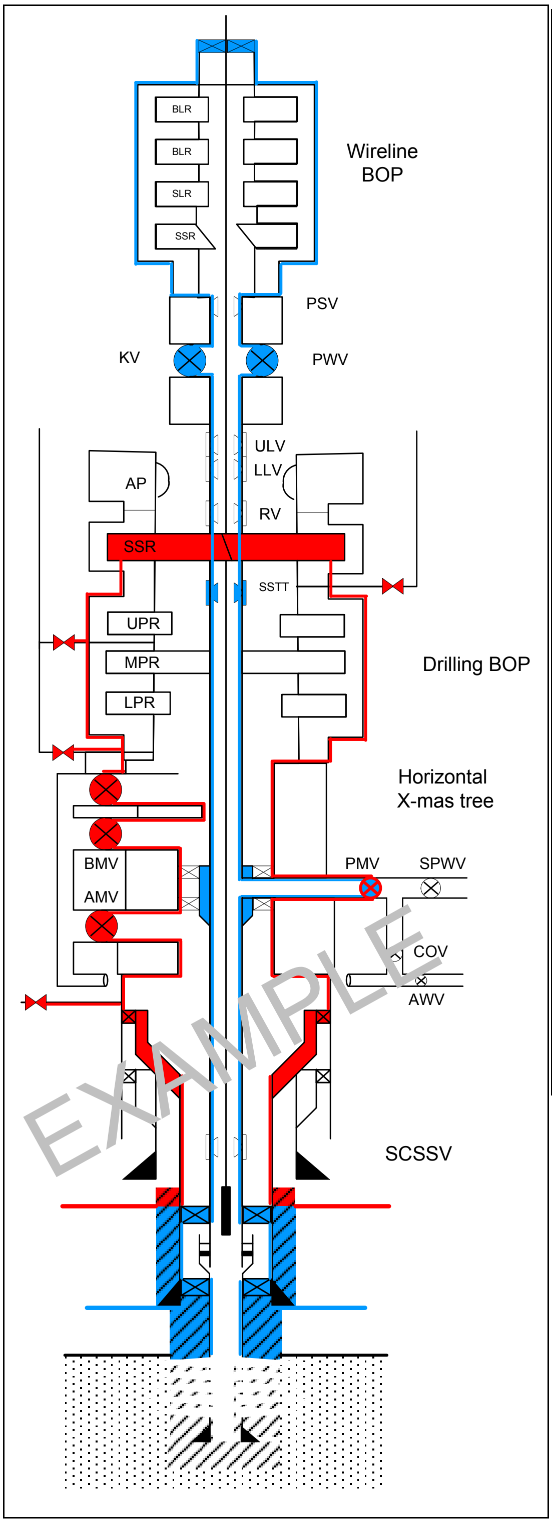
*Common WBE.

Figure 10.7.2 – Running wireline through surface tree



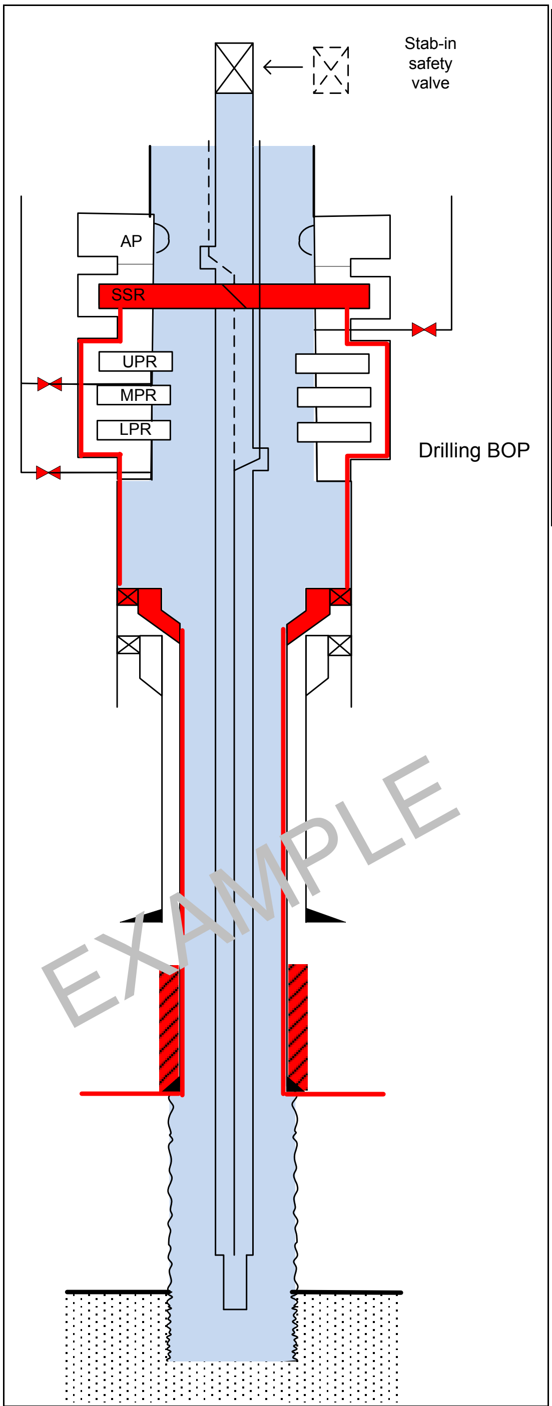
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production packer	7	
Completion string	25	
Tubing hanger	10	
Subsea tree	31	
Lower riser packer	42	
High pressure riser	26	
Surface test tree	34	
Wireline BOP	37	
Wireline lubricator	44	
Wireline stuffing box / grease injection head	39	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing hanger	10	
Subsea tree	31	
Lower riser package	42	

Figure 10.7.3 – Running wireline through subsea vertical tree with LRP



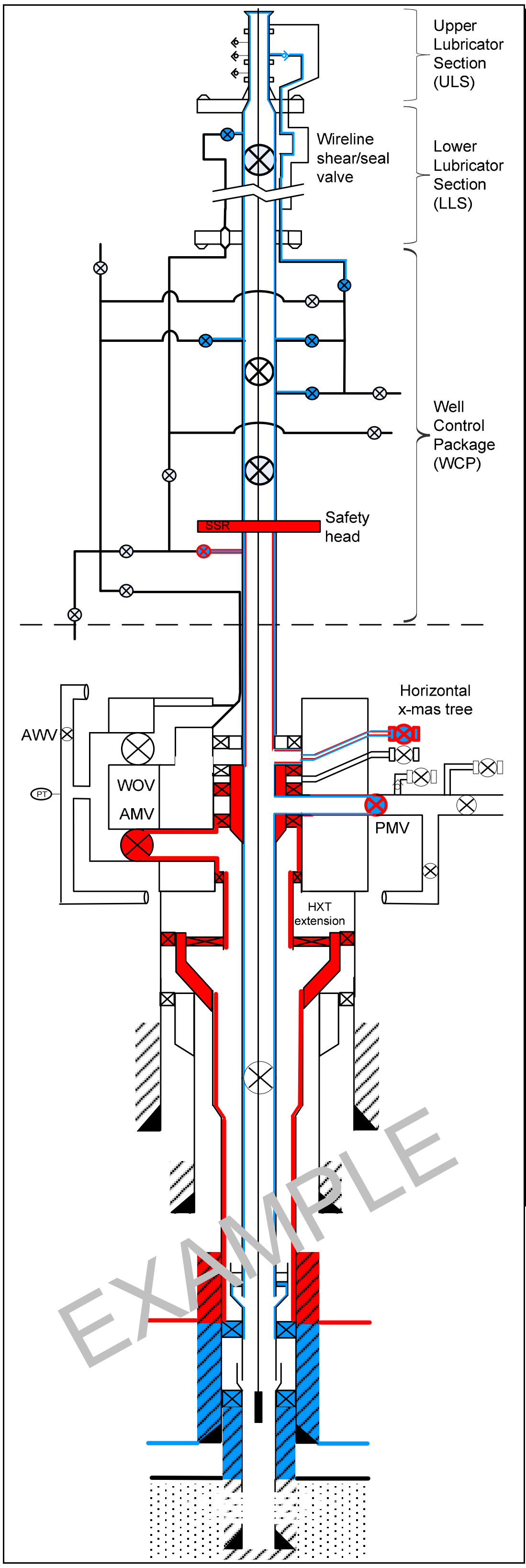
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production packer	7	
Completion string	25	
Tubing hanger	10	
Subsea tree	31	
Subsea test tree	32	
Well test string	27	
Surface test tree	34	
Wireline BOP	37	
Wireline lubricator	44	
Wireline stuffing box / injection grease head	39	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing hanger	10	
Subsea tree	31	
Drilling BOP	4	

Figure 10.7.4 – Subsea horizontal tree with drilling BOP and SSTT



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Fluid column	1	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser	26	
Drilling BOP	4	

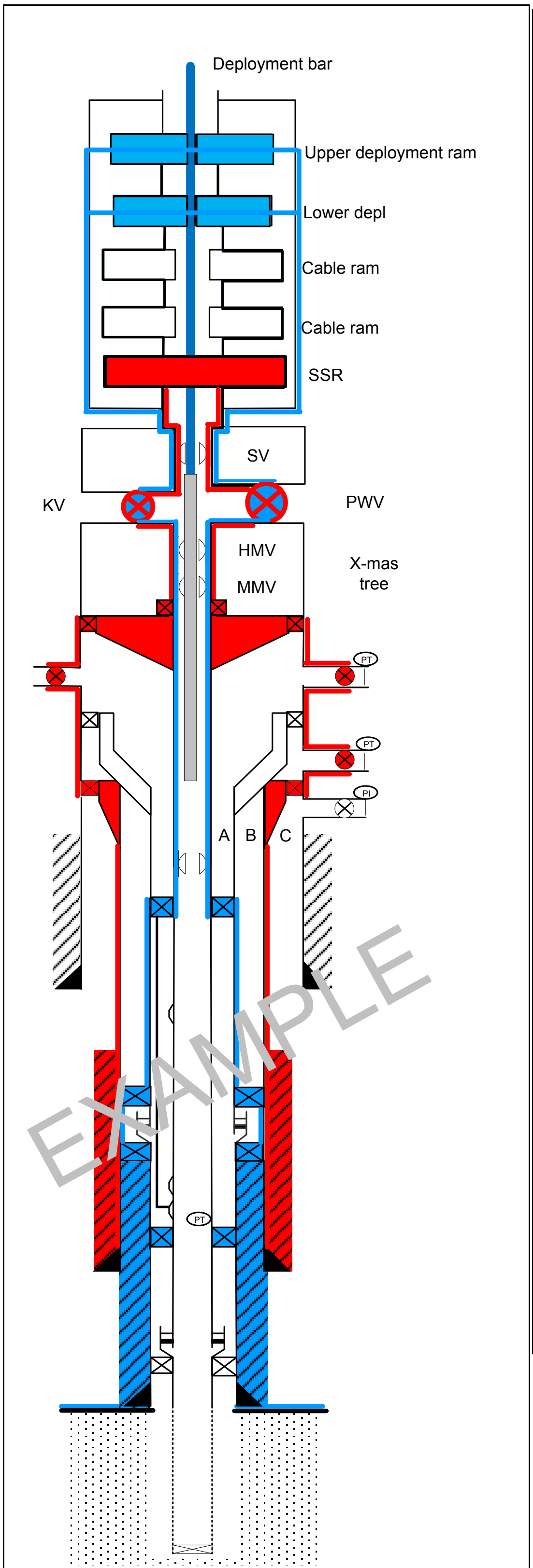
Figure 10.7.5 – Wireline logging on drillpipe



Well barrier elements	EAC table	Verification/monitorin
Primary well barrier		
Casing cement (liner)	22	
Casing (liner)	2	
Liner top packer	43	
In-situ formation	51	
Casing cement (shoe to production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
DHSV / control line	8	
Tubing hanger	10	
Subsea tree (HXT)*	31	
Well Control Package (WCP)*	57	
Lower Lubricator Section (LLS)	58	
Upper Lubricator Section (ULS)	59	
Secondary well barrier		
In-situ formation	51	
Casing cement (above production packer)	22	
Casing (above production packer)	2	
Casing hanger with seal assembly	5	
Subsea tree (HXT)*	31	
Tubing hanger with seals	10	
Well Control Package (WCP)*	57	

*Common WBE.

Figure 10.7.6 – Running wireline, horizontal tree, LWI



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Liner cement	22	
Liner	2	
Liner hanger packer	43	
Casing (between tie-back packer and liner hanger packer)	2	
Tie-back packer	43	
Tie-back casing	2	
Production packer	7	
Completion string	25	
Completion string component (Chemical Injection valve)	29	
ASV	9	
Surface tree*	33	
Wireline BOP (deployment bar and rams)	36	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Casing hanger with seal assembly	5	
Wellhead (A-annulus valve)	12	
Wellhead (B-annulus valve)	12	
Tubing hanger with seals	10	
Wellhead (WH/tree connector)	5	
Surface tree*	33	
Wireline BOP (shear seal ram)	36 37	

*Common WBE.

Figure 10.7.7 – Deployment

11 Coiled tubing operations

11.1 General

This section covers requirements and guidelines pertaining to well integrity during CT operations. A CT operation is a technique for deployment of various tools (logging tools, drilling tools, packers, etc.) and as a conduit for circulating or placing fluids in the well. CT can be deployed in pressurised wells or in dead wells.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute this activity in a safe manner.

11.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (11.8).

11.3 Well barrier acceptance criteria

The following list defines specific requirements and guidelines for well barriers:

a) Surface well control equipment for a CT operation in a completed well shall consist of:
   1. 2 x CT stripper;
   2. CT BOP;
   3. high pressure riser;
   4. CT safety head.

b) All connections from the XT to the top of the CT BOP shall be flanged or clamped and have metal to metal seals. Alternative connections and seals may be used when qualified specifically for the intended purpose (subsea riser, etc.).

c) Valve inlets or outlets in the surface control rig-up shall be double with flanged or clamped connections. The inner valve shall be bi-directional with metal-to-metal seal in the bore. One of the two valves shall be remotely operated. Alternatively on inlets, the remote operated valve may be replaced by a manual valve and a check valve.

d) A pressure rated line shall be connected to the kill inlet of the surface well control equipment.

e) If the DHSV is leaking, a safety head shall be installed and leak tested prior to rigging up the CT well control equipment.

f) For overbalanced coiled tubing operations, a method for monitoring volume in surface pits and maintaining the fluid level in the well shall be in place when deploying long BHA in an open well. The monitoring system shall be able to measure the displacement of the BHA.

g) When deploying a long BHA that cannot be cut, a contingency joint and/or a system for dropping the BHA in the well shall be in place.

h) The shear/seal ram on the LRP is the upper closure device in the secondary well barrier when running CT in completed SSWs. The same requirements therefore apply to the LRP shear/seal ram as for the safety head used on fixed installations.

i) The shear/seal ram in the subsea drilling BOP is defined as the upper closure device in the secondary well barrier when a subsea drilling BOP is installed when running CT in SSWs. The shear/seal ram in the subsea drilling BOP shall have the same requirements as the safety head on fixed installations.

j) Two well barriers are still maintained if the CT is parted or ruptured above the stripper and it is verified that:
   1. there is no influx of well fluids in the CT string;
   2. the check valves are not leaking.

See NORSOK D-002 for technical requirements.

11.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 28 – Additional EAC requirements

Table No.	Element name	Additional features, requirements and guidelines
16	CT safety head	If other valves below the safety head comply with the requirements in NORSOK D-002, they can replace the safety head.
32	Subsea test tree	The function of the SSTT is to seal off the test string or work over riser with or without CT present. The lower valve in the SSTT shall be capable of shearing one CT string including any wire, electric line or capillary line inside. The upper valve shall be capable of obtaining and maintaining a pressure seal. The SSTT valves are back-up elements in the primary well barrier, i.e. the SSTT valves will constitute the upper closure device in the primary well barrier after disconnect when the DHSV is not available. When the riser is connected, the combination of SSTT valves and subsea drilling BOP pipe ram are back-up elements in the secondary well barrier, i.e. to the sub-sea drilling BOP shear/seal ram.

11.5 Well control action procedures and drills

11.5.1 Well control action procedures

The following table describes incident scenarios for well control action procedures which should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 29 – Well control action procedures

Item	Description	Comments
1.	Power unit, injector head, tubing reel or control system failure	Fixed and floating installation
2.	Well fluid return system failure	Fixed and floating installation
3.	Circulating system or pumping failure	Fixed and floating installation
4.	CT string runaway	Fixed and floating installation
5.	Leak in the CT string	Fixed and floating installation
6.	Collapsed CT string	Fixed and floating installation
7.	Stuck CT string	Fixed and floating installation
8.	Leak in the CT upper stripper	Fixed and floating installation
9.	Leak in the CT BOP pipe ram	Fixed and floating installation
10.	Leak in the CT BOP shear/seal ram	Fixed and floating installation
11.	External leak in riser below safety head	Fixed installation
12.	External leak in riser above safety head	Fixed installation
13.	Leak in the hydraulic master valve while lubricating BHA against swab valve	Fixed installation
14.	Lubricating long BHA into a dead well	Fixed and floating installation
15.	Leak in lubricator valve while lubricating BHA against lubricator valve	Floating installation
16.	Leak in test string below SSTT	Floating installation
17.	External leak in landing string	Floating installation
18.	External leak in riser above or below LRP	Floating installation
19.	Controlled disconnect	Floating installation
20.	Emergency disconnect	Floating installation
21.	Emergency situation on rig/platform	Fixed and floating installation
22.	Running non-shearable tools across CT safety head	Fixed and floating installation

11.5.2 Well control action drills

Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts.

11.6 Well design

There are no specific requirements or guidelines relating to well design.

11.7 Other topics

11.7.1 Hydrate prevention

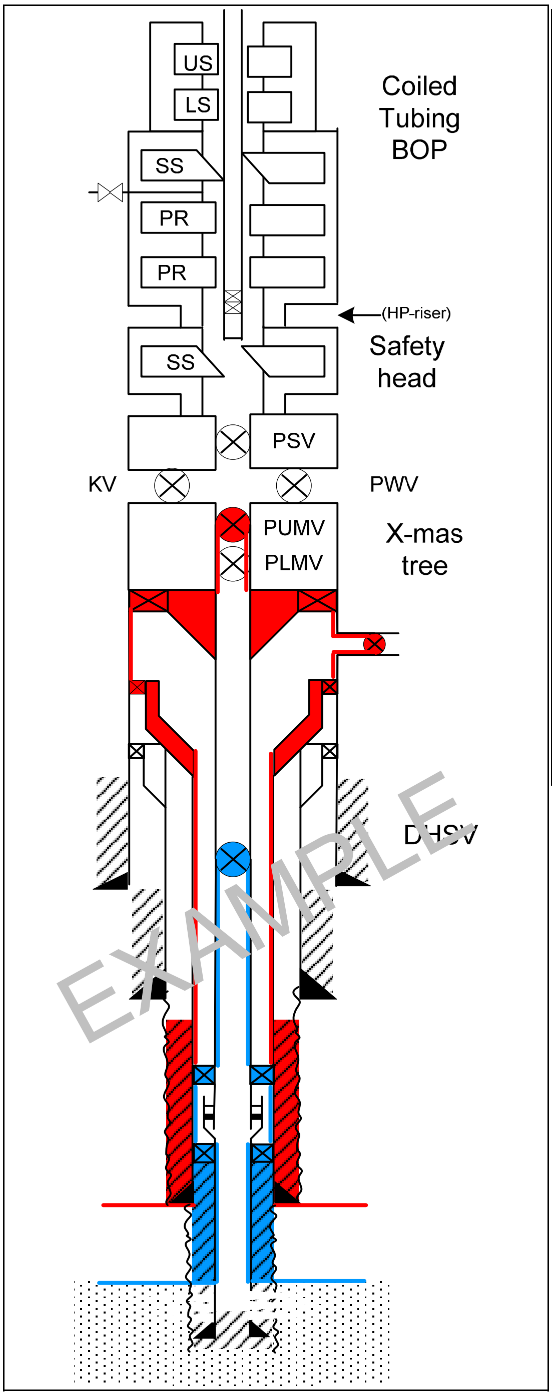
A hydrate-inhibited fluid shall be used when there is a risk for forming hydrates.

11.7.2 Floater specific operating and safety requirements

Because of the heave motion between the CT reel and gooseneck, precautions shall be made to prevent activation of the reel break by mistake. If the reel brake is automatically activated in the event of lost hydraulic pressure, this function should be overridden.

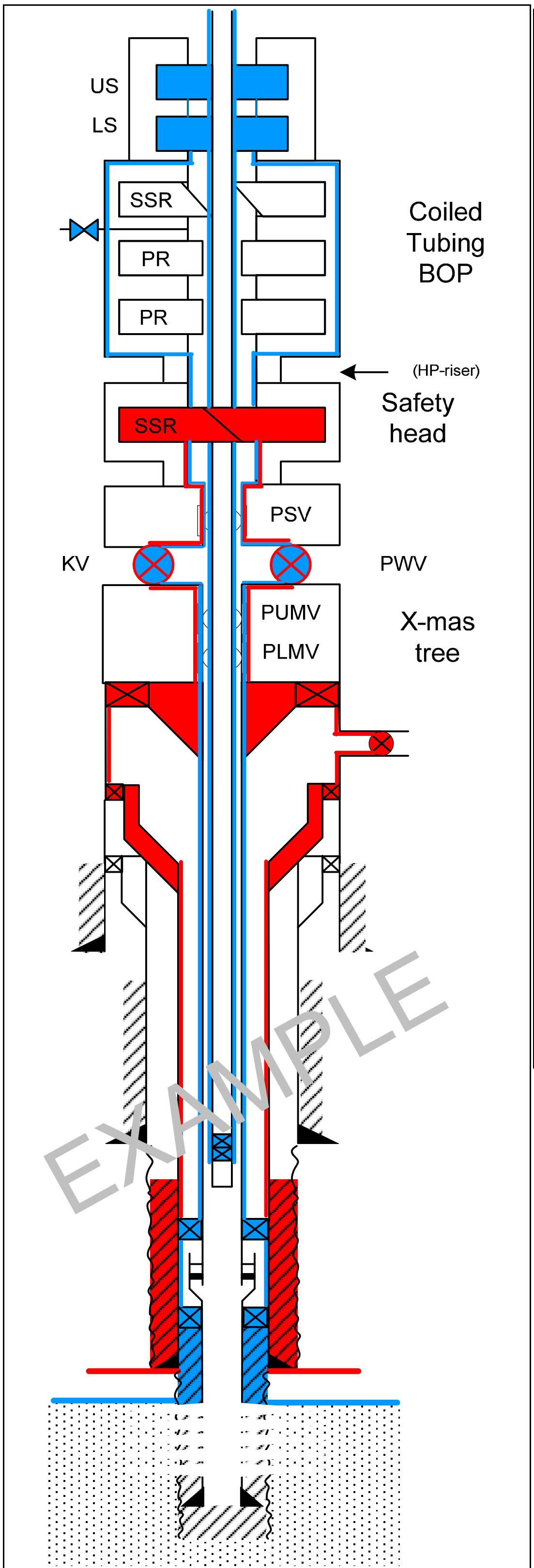
11.8 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



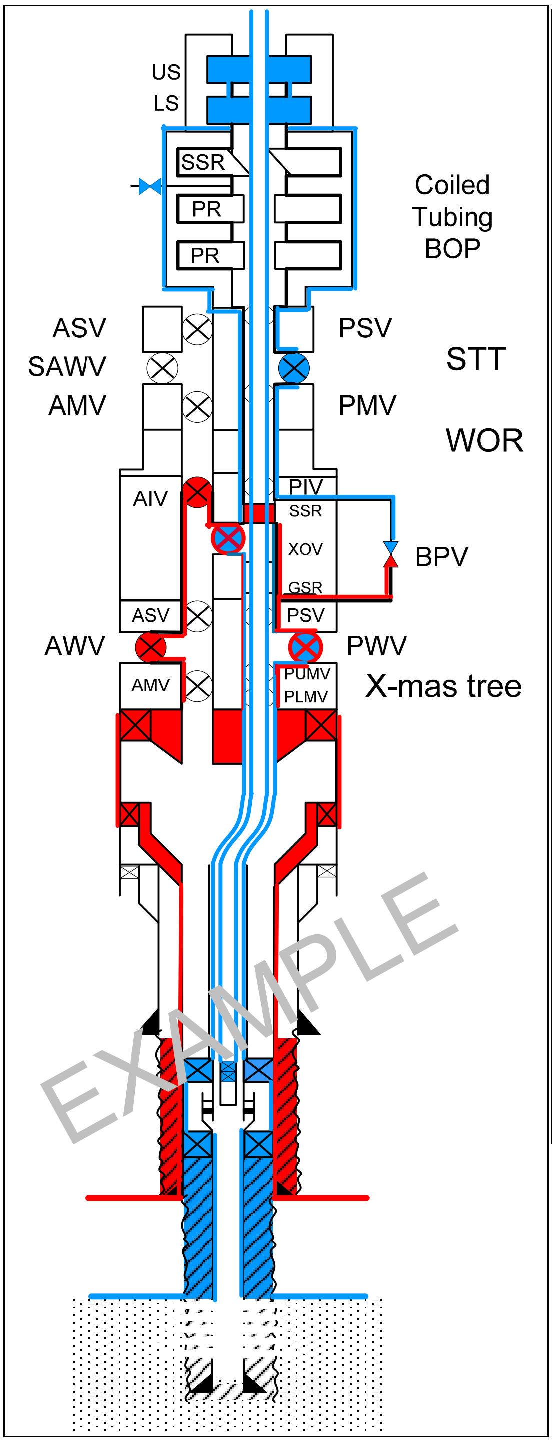
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Liner top packer	43	
Production packer	7	
Completion string	25	
DHSV	8	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead (Annulus valve and WH/XT connector)	5	
Tubing hanger	10	
Surface production tree	33	

Figure 11.8.1 – Running CT equipment above production tree



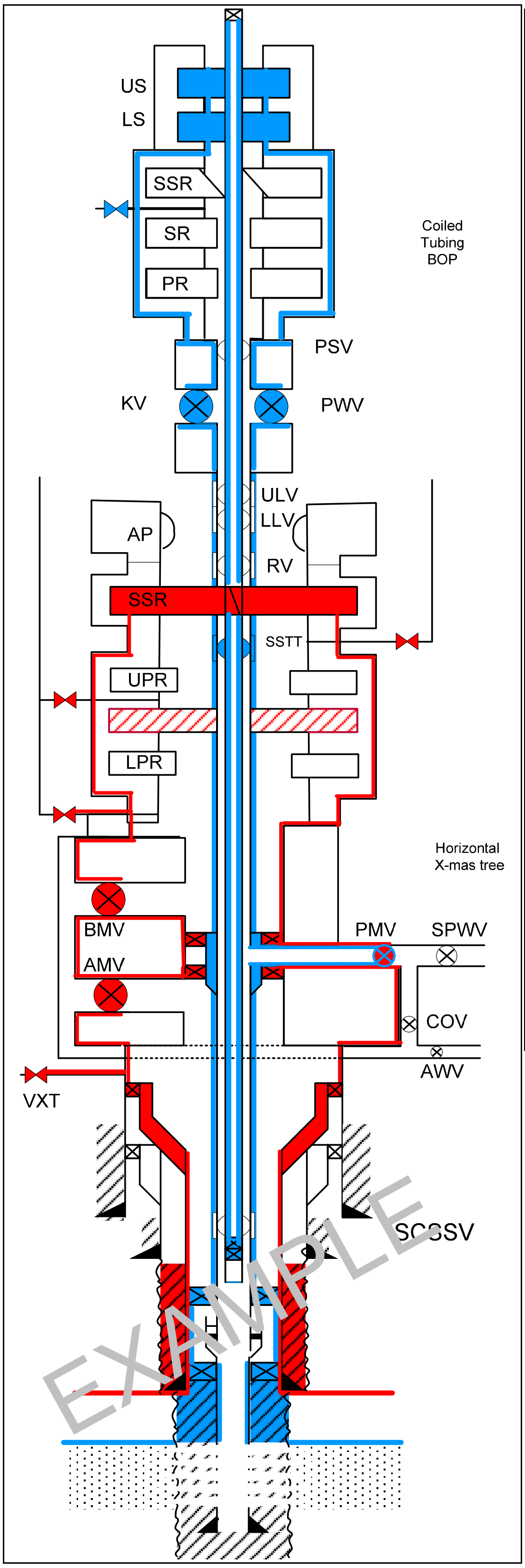
Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Liner top packer	43	
Production packer	7	
Completion string	25	
Tubing hanger	10	
Surface production tree	33	
Coiled tubing safety head	16	
High pressure riser	26	
Coiled tubing BOP	14	
Coiled tubing strippers	17	
Coiled tubing	13	
Coiled tubing check valves	15	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead (Annulus valve and WH/XT connector)	5	
Tubing hanger	10	
Surface production tree	33	
Coiled tubing safety head	16	

Figure 11.8.2 – Running CT equipment through surface production tree



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Liner top packer	43	
Production packer	7	
Completion string	25	
Tubing hanger	10	
Subsea production tree	31	
Lower riser package	42	
High pressure riser	26	
Surface test tree	34	
Coiled tubing BOP	14	
Coiled tubing strippers	17	
Coiled tubing	13	
Coiled tubing check valves	15	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead (Casing hanger and access line with valves)	5	
Tubing hanger	10	
Subsea production tree	31	
Lower riser package	42	

Figure 11.8.3 – Running CT through vertical subsea production tree with LRP



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Liner top packer	43	
Production packer	7	
Completion string	25	
Tubing hanger	10	
Subsea production tree	31	
Subsea test tree	32	
High pressure riser	26	
Surface test tree	34	
Coiled tubing BOP	14	
Coiled tubing strippers	17	
Coiled tubing	13	
Coiled tubing check valves	15	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead (Casing hanger and access line with valves)	5	
Subsea production tree	31	
Drilling BOP	4	

Figure 11.8.4 – Running CT through horizontal subsea production tree with drilling BOP and SSTT

12 Snubbing operations

12.1 General

This section covers requirements and guidelines pertaining to well integrity during snubbing operations. Snubbing operations is a technique for deployment of tools and equipment by use of jointed pipe and as a conduit for circulating or placing fluids in the well. Snubbing string can be deployed in pressurised wells or in dead wells.

The purpose of this clause is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner.

See Section 13 for deployment of drilling and completion strings by use of drilling BOP and RCD in pressurised wells.

12.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (12.8).

12.3 Well barrier acceptance criteria

The following requirements and guidelines apply:

a) The surface well control equipment for snubbing operation should consist of (top to bottom):
   1. stripper bowl or active stripper;
   2. dual stripper rams;
   3. snubbing BOP and riser;
   4. safety head (shear/seal ram).

b) A pressure rated line shall be connected to the kill inlet of the well control rig-up.

c) A safety head shall be installed and leak tested prior to rigging up the snubbing well control equipment.

d) For overbalanced snubbing operations, a method for monitoring of displacement volumes and maintaining the fluid level in the well shall be in place when deploying long BHA in an open well.

e) When deploying a long BHA that cannot be cut, a contingency joint and/or a system for dropping the BHA in the well shall be in place.

f) All tools or components that the safety head cannot cut shall be identified. Procedures for activation of the secondary well barrier when non-shearable tools or components are positioned across the safety head shall be described.

g) A wireline conveyed bridge plug for setting inside of the pipe being snubbed should be available.

h) Minimum two pump down plugs for each "N" nipple profile size specified in the program shall be on location. Pump down plug assembly with pump open (circulation through) feature shall have internal metal-to-metal seal.

i) The BHA shall be equipped with 2 check valves located in the lower part of the BHA.

j) An inside BOP or stabbing valve shall be available in the workbasket.

k) The length from the swab valve to upper stripper ram will normally be the WBE limit when defining the lubrication length.

See NORSOK D-002 for technical requirements.

12.4 Well barrier elements acceptance criteria

There are no additional requirements to what is described in section 15.

12.5 Well control action procedures and drills

12.5.1 Well control action procedures

The following table describes incident scenarios for well control action procedures which should be available. This list is not comprehensive and additional scenarios may be applied based on the planned activities.

Table 30 – Well control action procedures

Item	Description	Comments
1.	Unintentional shut down of main rig and auxiliary systems	Fixed installation
2.	Failure of power unit and loss of main hydraulic circuits	Fixed installation
3.	Slip bowl failure	Fixed installation
4.	Stripper rubber failure	Fixed installation
5.	Annular BOP leaking	Fixed installation
6.	Stripper BOP rams/active stripper leaking	Fixed installation
7.	Leak in upper pipe ram	Fixed installation
8.	Leak in lower pipe ram	Fixed installation
9.	Leak in shear/blind ram	Fixed installation
10.	Leak which can not be controlled by BOP stack	Fixed installation
11.	*Well control system* Unintentional closing of shear/blind or undersized ram External leak in safety head with work string above DHSV if applicable Work string below DHSV External leak below safety head External leak while WL through the snubbing unit Inside leak while wireline through snubbing pipe Choke system failure.	Fixed installation
12.	*Workstring* Inside blowout Intentional dropping of the workstring Unintentional dropping of the workstring Intentional shearing of the workstring Parting of workstring Buckling of workstring	Fixed installation
13.	*Lubrication of screens* Winch failure while MU or LD of screens Leak in DHSV Leak in DHSV – above point of no return Unintentional dropping of screens	Fixed installation
14.	*Lubrication of guns* Leak in DHSV. Unintentional dropping of guns. Power unit failure. Gun run – Surface deployment system.	Fixed installation
15.	*Emergency situation on rig/ platform* Muster alarm general instructions Abandon Alarm developing from muster alarm Abandon alarm without muster alarm first	Fixed installation

12.5.2 Well control action drills

Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts.

12.6 Well design

There are no specific requirements or guidelines relating to well design.

12.7 Other topics

12.7.1 Hydrate prevention

Hydrate-inhibited fluid shall be used when there is a risk for forming hydrates.

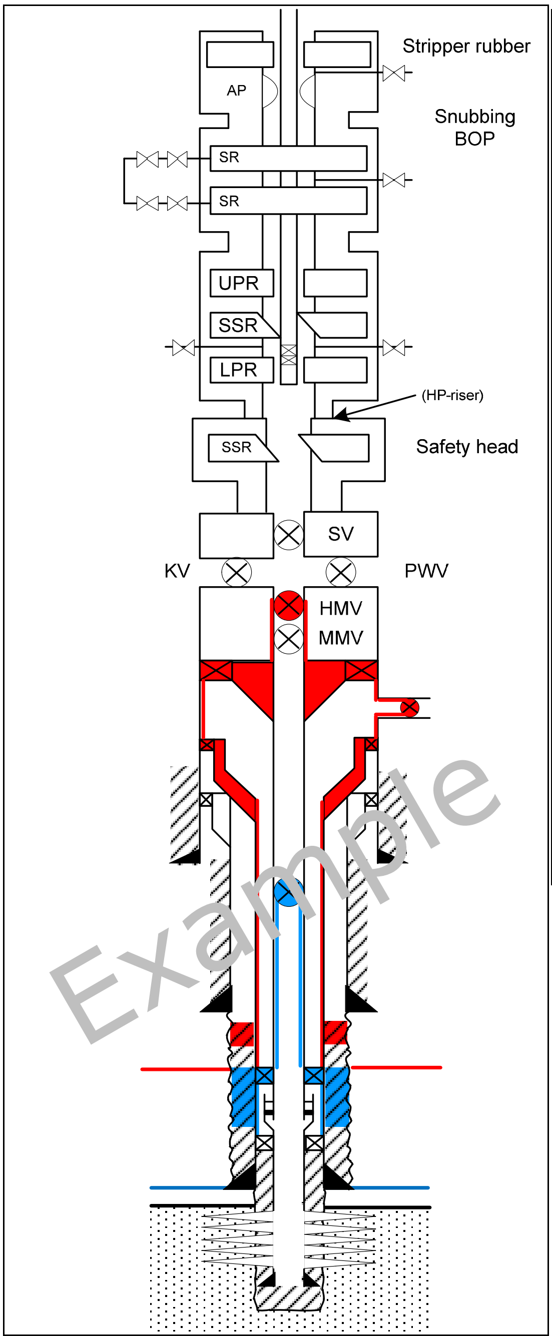
12.7.2 Snub/heavy force limitation

The operational limit value settings for the surface snubbing equipment with regards to torque, pull and push (snub and heavy force limit) shall be set based on the workstring and BHA mechanical properties and configuration.

The balance point shall be determined and documented.

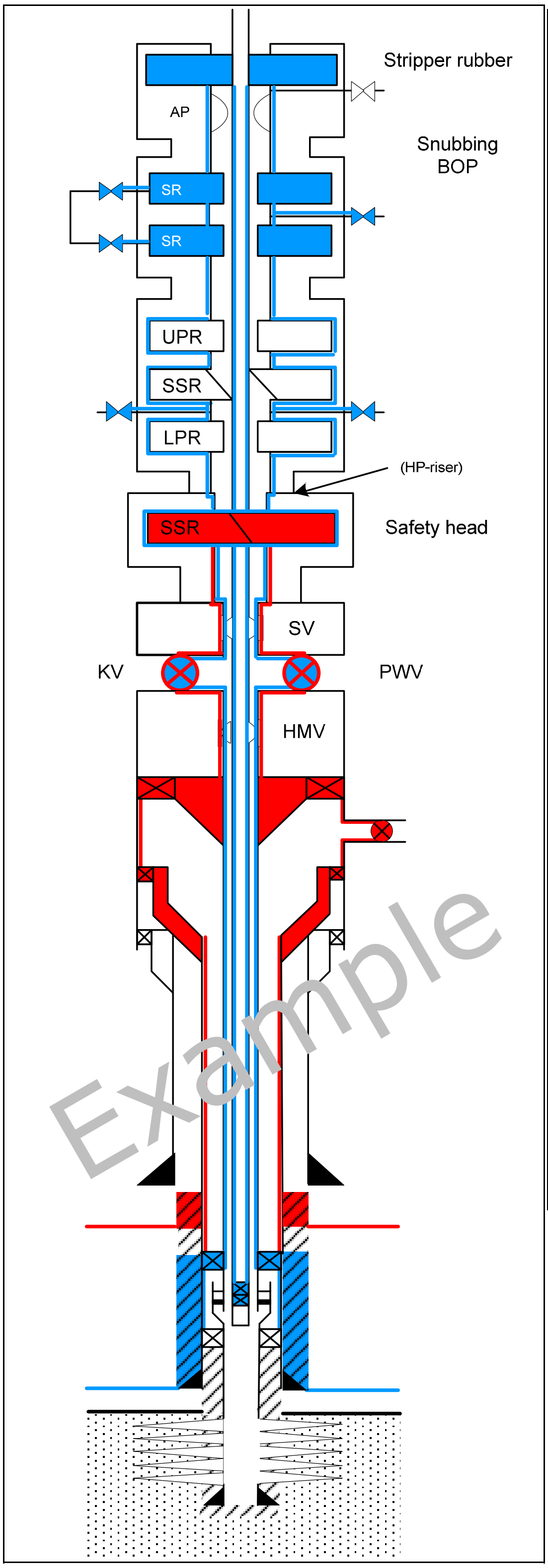
12.8 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (below production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
DHSV	8	
Secondary well barrier		
In-situ formation	51	
Casing cement (above production packer)	22	
Casing (above production packer)	2	
Wellhead (Annulus valve and XT/WH connector seal)	5	
Tubing hanger	10	
Surface production tree	33	

Figure 12.8.1 – Rigging snubbing equipment above production tree



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement (below production packer)	22	
Casing (below production packer)	2	
Production packer	7	
Completion string	25	
Tubing hanger (body)	10	
Surface production tree	33	
Snubbing safety head	21	
High pressure riser	26	
Snubbing BOP	19	
Snubbing strippers	20	
Snubbing string	30	
Snubbing check valves	18	
Secondary well barrier		
In-situ formation	51	
Casing cement (above production packer)	22	
Casing (above production packer)	2	
Wellhead (Annulus valve and XT/WH connector seal)	5	
Tubing hanger	10	
Surface production tree*	33	
Snubbing safety head*	21	

*Common WBE.

Figure 12.8.2 – Running workstring into live well – shear ram able to shear

13 Under balanced and managed pressure drilling and completion operations

13.1 General

This section covers requirements and guidelines pertaining to well integrity during underbalanced drilling/completion (UBD) and managed pressure drilling/completion (MPD) operations, using jointed pipe which can be rotated at surface, and the following systems:

a) MPD: Systems manipulating annular pressure at surface to control and manage downhole pressures using static underbalanced fluid.
b) UBD: Systems manipulating annular pressure at surface to control and manage downhole pressures and formation inflow rates used for drilling hydrocarbon bearing formations (i.e. not air drilling).

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional requirements and guidelines to execute UBD and MPD operations in a safe manner.

The standard is written for MPD/UBD operations using a surface BOP.

13.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (13.8).

13.3 Well barrier acceptance criteria

13.3.1 General well barrier acceptance criteria in underbalanced and managed pressure drilling

The following apply:

a) All WBEs shall be rated to withstand the maximum differential pressure expected for planned operation mode (UBD or MPD) including a predefined safety factor.
b) A complete list of possible leak paths shall be made.
c) A risk assessment shall be done to assess common WBEs. As a minimum, well type (new/re-entry), status, certifying frequency, visual/mechanical surveillance and probability and consequence of failure of each elements should be addressed.
d) A system/equipment acceptance plan shall be made prior to installation.

13.3.2 Well barrier acceptance criteria for underbalanced drilling

The primary well barrier during UBD operations is maintained by fluid column and pressure control.

The BHP and the reservoir influx shall be monitored and controlled by means of a closed loop surface system including an RCD, flowline, ESDV, choke manifold and surface separation system:

a) The RCD shall be installed above the drilling BOP.
b) Gas detection devices shall be installed to detect possible leaks from connections on the wellhead, high pressure riser and BOP.
c) A dedicated UBD choke manifold shall be used to control the flow rate and wellbore pressure, and reduce the pressure at surface to acceptable levels before entering the separation equipment. The choke manifold shall have two chokes and isolation valves for each choke and flow path.
d) A surface separation system shall be selected and dimensioned to handle the anticipated fluid/solids in the return flow. Plugging, erosion or wash-outs of surface equipment shall not impact the ability to maintain primary well control. Surface separation systems shall have documented capability and suitability for the area they are to be located. Specifications of surface separation equipment (i.e. separators, sample catcher system, flare systems) and support systems are not included in this NORSOK standard. See API RP 92U Underbalanced Drilling Operations.
e) Snubbing facilities shall be used or the well shall be killed with a kill weight fluid prior to tripping pipe, if the shut-in or flowing wellhead pressure can produce a pipe light condition and a DIV, a retrievable packer system or similar shut-in device, is not in use or is not functioning as designed.

f) If the inflow potential exceeds the capacity of the surface equipment then the primary well barrier will no longer function as intended and thus the well shall be secured.
g) The UBD fluid system can consist of basic liquids such as seawater, fresh water, brine, crude or base oil, occasionally combined with gas injection. Weighting material requirement depends on the reservoir pressure and the degree of draw down desired. The selected UBD fluid shall be suitable for the application it is chosen for.
h) In the planning and design phase, multiphase flow modelling shall be done. The results of the modelling and other design parameters shall be used for equipment selection and in procedures prior to start of operations. Within these procedures the BHP operating envelope shall be set based on best available data. Optimal operating parameters for the execution phase shall be based on real time phase behaviour modelling and actual well and reservoir conditions. Dynamic simulators should as a minimum be used to model the effects of starting and stopping circulation and the fluid interaction during connections.

The elements in the secondary well barrier are the same in UBD as in conventional drilling:

i) A drilling BOP shall be installed for UBD.
j) A stab-in safety valve for the pipe in use shall be available on the rig floor.

13.3.3 Well barrier acceptance criteria for managed pressure drilling

The primary well barrier in MPD operations is maintained by a statically underbalanced fluid column with applied surface pressure. The BHP is controlled by means of a closed loop surface system and equipment providing back-pressure.

a) The RCD shall be installed above the drilling BOP.
b) A dedicated MPD choke manifold shall be used to control the wellbore pressure and reduce the pressure at surface to acceptable levels before entering the separation equipment or the shakers. A manual MPD choke system is not accepted as a part of the primary well barrier.
c) Plugging, erosion or wash-outs of surface equipment shall not impact the ability to maintain well control.
d) The surface system shall be selected and dimensioned to handle the anticipated fluid/solids, including formation fluids if potential exists for influx removal with MPD.
e) Snubbing facilities shall be used in all pipe light scenarios. Alternatively, the well can be brought into hydrostatic overbalance or a qualified isolation WBE can be placed down hole prior to any probable pipe light scenarios.
f) During any tripping operation, the ability shall be in place to measure either positive backpressure if the RCD is installed, or verify level of liquid in the annulus when the RCD is not installed.
g) The BHP shall be kept at a level that prevents continuous influx of formation fluid into the well. The BHP shall be above maximum confirmed pore/reservoir pressure (including safety margin to account for expected variations in BHP). The pressure can be confirmed by pressure measurement or interpreted from well signals.

The secondary well barrier for MPD is the same as for conventional drilling.

h) A stab-in safety valve for the pipe in use shall be available on the rig floor.
i) A drilling BOP shall be installed for MPD operations
j) MPD manifold and flow path shall be independent of rig choke manifold, so the rig choke manifold is always available for well control operations.

To ensure that the wellbore pressure does not exceed the formation integrity, the following apply:

k) A minimum kick tolerance shall be specified. Based on the MPD system's capability of recognising small influxes and minimising influx volumes, the kick tolerance can be smaller than for conventional operations.
l) The open hole wellbore pressure range "drilling window" shall as a minimum be such that the MPD system is proved capable of operating within the window for both planned operations and selected predefined contingencies, which shall be based on criticality and frequency of occurrence. As a minimum loss of rig power, choke plugging, change of RCD element and switch between MPD and well control mode (and vice versa) shall be included.

m) Stop criteria for lack of kick margin and/or being outwith of operating range shall be made. A contingency plan shall be in place and include actions to be taken if this occurs.
n) If the minimum formation stress is lower than the maximum estimated pore pressure in the section, it shall be documented that the risk of fracturing the formation is acceptable, and contingency plans for potential scenarios shall be made.

13.4 Well barrier elements acceptance criteria

There are no additional requirements to what is described in section 15.

13.5 Well control action procedures and drills

13.5.1 Well control action procedures

Main operational risks shall be identified and contingency procedures shall be made, reflecting the actual equipment to be used and the well specific data.

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be included based on the planned activities.

Table 31 – Well control action procedures

Item	Description	Comment
1.	Bottom hole or surface pressure and/or flow rates detected which could lead to the pressure rating of the RCD (static or dynamic) or the capacity of the surface separation equipment being exceeded	
2.	NRV failure, influx into work string during making connection or tripping in live well	
3.	Leak in common WBE; casing	
4.	Leak in common WBE; casing cement	
5.	Leak in common WBE; WH, HP-riser and BOP	
6.	Gain while: drilling, displacing to overbalance fluid, and with pipe out of hole	MPD only
7.	Erosion or wash out of choke	Consider the case where isolation for repair of the choke cannot be achieved
8.	Leaks at surface	RCD, flowlines, manifold etc.
9.	Plugging at surface	Choke, flowmeter etc.
10.	Work string failure, washout or twist-off	Consider pipe light scenario and contribution from additional NRVs in the drillstring. Evaluate risk for pipe failure based on well path/dog leg severity
11.	Emergency shut-in	UBD only
12.	Emergency well kill and bullheading	Including criteria for shut-in
13.	Lost circulation, on bottom and out of hole	
14.	H_2S in the well	
15.	Loss of rig power	
16.	Simultaneous kick and loss situation	
17.	Stuck pipe	
18.	Failure of method to hold dynamic backpressure during connections	
19.	Rig movement	
20.	Rig/platform alarm with mustering	

13.5.2 Well control action drills

The following well control action drills should be performed:

Table 32 – Well control action drills

Type	Frequency	Objective	Comment
Pressure rating of the RCD (static or dynamic) being exceeded	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
The capacity of the surface separation equipment being exceeded	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD operation
Leaking NRV, influx into work string on making connection or tripping in live well	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
Leak in RCD. Including stripping to change element	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
Leak in equipment downstream of RCD	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
Leak in drilling BOP lower connector	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
Choke drill	Once prior to starting UBD/MPD operations with crew on tour	Practice in operating the power choke with pressure in the well	Before drilling out of the last casing prior to UBD/MPD operation
Uncontrolled work string movement out of well	Once per well with crew on tour	Response training	Before drilling out of the last casing prior to UBD/MPD operation
H_2S drills	Prior to drilling into a potential H_2S zone/reservoir	Practice in use of respiratory equipment	All relevant personnel to have necessary training if H_2S is known to be present
Transferring between use of well control equipment and UBD/MPD equipment	Once prior to starting UBD/MPD operations with crew on tour	Practice in changing from UBD/MPD mode to standard well control mode (in case of a kick situation)	Before drilling out of the last casing prior to UBD/MPD operation

13.6 Well control matrix

A well control matrix shall be prepared. Criteria for stopping operation and observe (yellow zone) and definition of well control incident including first action shall be included in the matrix. The well control matrix shall be well specific and based on the design limitations of the actual equipment that will be used during execution.

13.6.1 Well control matrix for MPD operations

The following is an example of an MPD well control matrix:

Table 33 – Well control matrix for MPD

		Surface Pressure Indicator			
		At Planned Drilling Back Pressure	At Planned Connection Back Pressure	> Planned Back Pressure & < Back Pressure Limit	≥ Back Pressure Limit
Influx Indicator (See Chart 1 Below)	No Influx	Continue Drilling	Continue Operation	Continue operation, adjust system to decrease WHP	Secure well, evaluate next planned action
	Operating Limit	Continue drilling, adjust system to increase BHP	Continue operation, adjust system to increase BHP	Continue operation, adjust system to decrease WHP and increase BHP	Secure well, evaluate next planned action
	< Planned Limit	Cease drilling, adjust system to increase BHP	Adjust system to increase BHP	Secure well, evaluate next planned action	Secure well, evaluate next planned action
	≥ Planned Limit	Secure well, evaluate next planned action	Secure well, evaluate next planned action	Secure well, evaluate next planned action	Secure well, evaluate next planned action

NOTES Operating limit: A well specific limit below which drilling can continue.

≥Planned limit: A well specific limit where MPD ceases and transitions to well control operations.

If potential formation fluid is planned to be handled through the MPD equipment, the risk shall be verified to be equal or lower than handling it through the rigs well control system.

a) It shall be possible to convert from MPD mode to conventional mode during a well control situation without increasing the risk compared to a conventional well control situation.
b) Procedures to handle larger or unexpected volumes shall be prepared before start of operation.
c) If formation fluid is planned to be circulated out using the MPD control system, real time pressure data should be available while the influx is circulated out.

The following is an example of a UBD well control matrix:

Table 34 – Well control matrix for UBD

UBD well control matrix		Wellhead Flowing Pressure Range 1 (P_1-P_2)	Wellhead Flowing Pressure Range 2 (P_2-P_3)	Wellhead Flowing Pressure >P_3
Surface Flow Rates	Range 1 (0-Q_1)	Continue drilling	Continue drilling Adjust system to decrease WHP	Secure well, evaluate next planned action
Surface Flow Rates	Range 2 (Q_1-Q_2)	Continue drilling Adjust system to increase BHP	Cease drilling Pick up, space out Adjust system to increase BHP and decrease WHP	Secure well, evaluate next planned action
Surface Flow Rates	> Q_2	Secure well, evaluate next planned action	Secure well, evaluate next planned action	Secure well, evaluate next planned action

Where:

P_1 = Minimum separator pressure to ensure effective dumping of fluids

P_2 = Planned operating pressure

P_3 = Operating pressure limit

Q_1 = Planned operating flow rate

Q_2 = Operating flow rate limit

13.7 Other topics

13.7.1 Procedures

Well specific procedures shall be developed for MPD/UBD operations. The procedures shall be based on risk analysis. The following operational requirements apply for MPD:

a) Dynamic flow checks shall replace standard flow checks. Dynamic flow checks are performed by stopping drilling and holding constant surface pressure while monitoring for gains or losses through the closed loop MPD system.
b) If unexpected formation fluid is planned to be handled through the MPD equipment, well control procedures shall be made.
c) Well/operation specific limitations shall be established, e.g. maximum and minimum BHP, kill rate, maximum tripping speed, etc.

Procedures should be developed for:

d) initiating underbalance/unloading the well (UBD only);
e) making connections;
f) live well tripping;
g) erosion monitoring;
h) trapped pressure in equipment;
i) communication interfaces;
j) change out of RCD bearings/elements.

13.7.2 Personnel training

The personnel involved in UBD and MPD operations shall be competent. Personnel in the process of becoming competent shall be supervised by competent personnel.

The following personnel shall complete a basic MPD/UBD course:

a) assistant driller;
b) driller;
c) toolpusher;
d) drilling supervisor;
e) MPD/UBD supervisor;
f) MPD/UBD operator;
g) drilling engineer;
h) drilling superintendent;
i) rig manager;
j) platform/site manager.

The above personnel (except platform/site manager) shall complete an installation specific course with a refresher course every second year.

The involved offshore personnel shall perform on site training before initiating the MPD/UBD operation, which shall include planned operations and contingencies. A plan shall be in place to ensure sufficient training for oncoming crews.

All the above training shall be documented.

MPD/UBD supervisor shall hold a valid well control certificate issued by a recognised international party (i.e. IWCF or IADC).

13.7.3 Data acquisition

Relevant real-time data shall be collected and displayed on screens on a continuous basis, including:

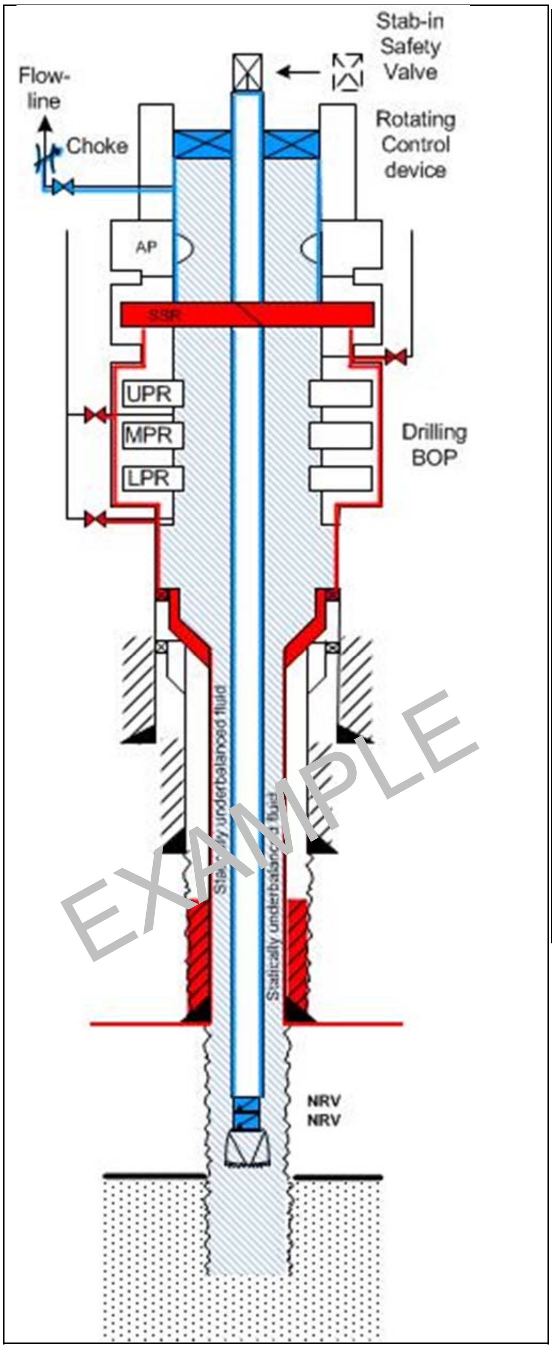
a) annulus/choke pressure;
b) standpipe pressure;
c) active surface system fluid volume;
d) drilling fluid pump rate;
e) returned gas rate (UBD);
f) returned liquid rate;
g) gas injection rate (if any);
h) surface equipment pressure;
i) surface temperature;
j) downhole pressure and temperature shall be included in the BHA (memory data should be recorded).

13.7.4 Relief well

In addition to the contingency requirements in section 4.8, an evaluation of the validity of the current relief well strategy shall be included in the drilling program for wells drilled with UBD/MPD. It shall include an evaluation of whether the relief well needs to be drilled with UBD/MPD. If UBD/MPD is required the suitability of available rigs to drill relief wells in UBD/MPD shall also be included.

13.8 WBS examples

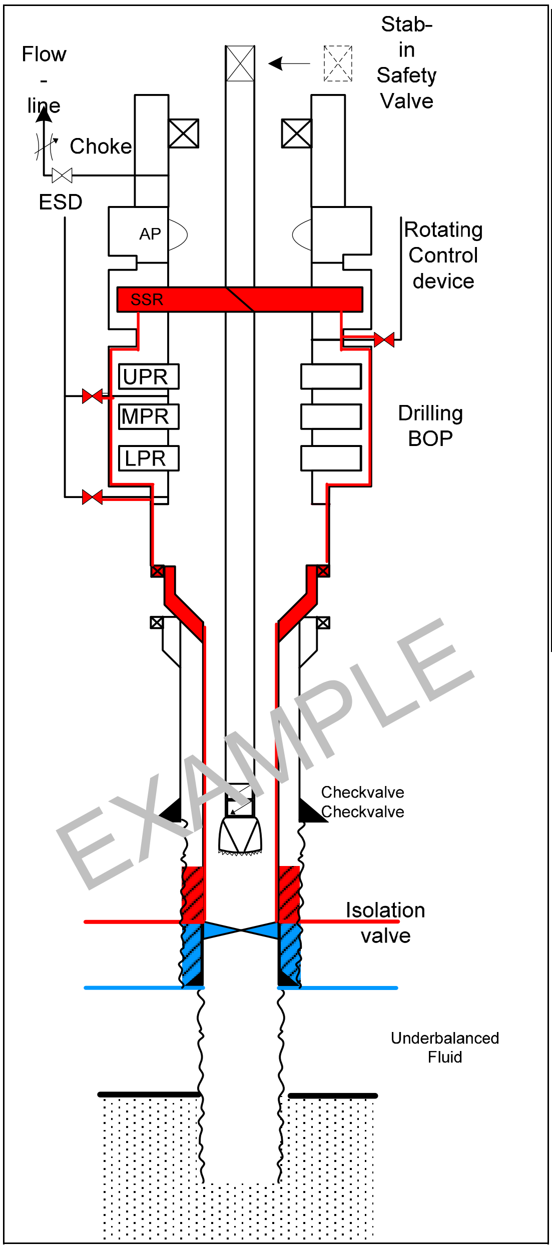
The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
Statically underbalanced fluid column	54	
Casing*	2	
Wellhead*	5	
High pressure riser*	25	
Drilling BOP*	4	
Rotating control device	48	
UBD/MPD non-return valve (NRV)	50	
Drill string or completion string	3 25	
UBD/MPD choke system	53	
Secondary well barrier		
In-situ formation	51	
Casing cement	21	
Casing*	2	
Wellhead*	5	
High pressure riser*	26	
Drilling BOP*	4	

*Common WBE.

Figure 13.8.1 – Drilling and tripping of string in UB fluid



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Downhole isolation valve	49	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
High pressure riser	26	
Drilling BOP	4	

Figure 13.8.2 – Tripping workstring using DIV

14 Pumping operations

14.1 General

This section covers requirements and guidelines pertaining to well integrity during pumping (injection) of fluids into a well through tubing and annuli. The duration of the pumping operations might be short term, when performing stimulation, corrosion treatment, scale treatment, energised fluid kick-offs, clean-outs, bullheading, killing or long term, when disposing slurryfied drill cuttings or waste.

Continuous injection of water and gas or other fluids into reservoirs for enhanced oil recovery and reservoir pressure maintenance is covered in Section 8. Cement pumping and injection tests are not included.

The purpose of this section is to describe the establishment of well barriers by use of WBE's and additional requirements and guidelines to execute this activity in a safe manner.

14.2 Well barrier schematics

A WBS shall be prepared for each well activity and operation.

Examples of WBSs for selected situations are presented at the end of this section (14.8).

14.3 Well barrier acceptance criteria

If the maximum pumping pressure exceeds the RWP of the tree, or a correspondingly lower pressure if tree pressure rating has been reduced by corrosion or erosion, the tree shall be isolated from the pumping pressure by a tree isolation tool.

Injection shall not be performed into any formation which has the ability to:

a) propagate vertical fractures to the seabed;
b) flow, unless there is a DHSV installed in the tubing or an ASV in the specific annulus used for injection, or if static hydrostatic pressure of the injected fluid column exceeds the pore pressure.

14.4 Well barrier elements acceptance criteria

The following table describes requirements and guidelines which are additional to the requirements in Section 15.

Table 35 – Additional EAC requirements

Table	Element name	Additional features, requirements and guidelines
22	Casing cement	Annulus or pipe bore below the injection point should be cemented and/or isolated to avoid injecting into a reservoir that is not intended for injection
33	Surface tree	Remotely actuated tree valves should be isolated from inadvertent closure during pumping operations

14.5 Well control action procedures and drills

14.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available. This list is not comprehensive and additional scenarios may be applied based on the planned activities.

Table 36 – Well control action procedures

Item	Description	Comments
1.	Leak in the tree isolation tool during pumping operation	
2.	Leak in the surface discharge lines	How to close isolated production tree valves

14.5.2 Well control action drills

Relevant well control action drills shall be performed before the operation commences with both shifts and thereafter once a week with both shifts.

14.6 Well design

14.6.1 General

See sections 5 and 7 for well design.

14.6.2 Design basis, premises and assumptions

It shall be verified that all well equipment and surface equipment can withstand the planned loads induced by the pumping operations. Historical operational data for the well shall be reviewed and the equipment pressure rating shall be downgraded based on measured or estimated material loss caused by corrosion, erosion and other factors that may have affected the integrity of the equipment.

14.6.3 Load cases

When designing for burst, collapse and axial load, the following load cases shall minimum be considered. This list is not comprehensive and actual cases based on the planned activity shall be performed.

Table 37 – Load cases

Item	Description	Comments
1.	Material compatibility verification	Material compatibility with all chemicals and mixtures of these chemicals which will be pumped.
2.	Maximum allowable pumping rate	Assess abrasive erosion from all fluids and its content (sand, gravel etc.) and pressure surge by accidental closure of a valve in the flow conduit when pumping at maximum allowable rate
3.	Maximum differential pressure	During the injection period
4.	Temperature impacts, tubular cooldowns and annular pressure build-up during flowback	During the injection period and until equilibrium is reached

14.6.4 Minimum design factors

Well string/components shall be designed to withstand all planned and/or expected loads and stresses including those induced during potential well control situations. The minimum design factors shall be as described in section 4.3.6.

14.7 Other topics

14.7.1 Pumping through production tubing

The following applies when pumping through production tubing:

a) The pump shall have pressure relief valve to protect against overloads. The relief valve should discharge into a non-hazardous location. The pump shall have an over pressure limit system that automatically stops the pump before overloads occur.
b) The DHSV and HMV should be isolated from inadvertent closure during pumping operations.
c) Neighbour annulus and/or pipes isolated from the injection shall be monitored on a regular basis for pressure build up. The cause of any pressure increase (temperature, pipe expansion or leak) shall be verified.
d) After pumping, all annuli (that can be monitored) shall be monitored regularly until the temperature equilibrium is reached.

14.7.2 Handling and pumping of energised fluids

The following applies when handling or pumping liquefied gases or liquids containing gases:

a) All surface hoses and piping lines used on the low pressure side of the liquefied gas shall be qualified for liquid gas service and the specific gas to be pumped.
b) It should be possible to drain the lowest point of surface hoses and piping lines to minimise the risk of having ice blocks.
c) All equipment used for storing and/or pumping liquefied gases shall be positioned in a bounded area.
d) The bounded area shall:
    1) be arranged to collect and contain accidental spills of liquefied gases;
    2) provide thermal insulation of deck and construction;
    3) have water hoses with fine spray nozzle available.
e) The discharge line should have a one-way check valve and pressure bleed-off arrangement.
f) Rubber hoses should not be used as a part of the high pressure discharge line.
g) The injection pump shall be fitted with a pressure limit switch, which shall be set to 1,1 times the maximum allowable pumping pressure.

14.7.3 Temporary installed surface discharge lines

When temporarily installed surface discharge lines (between the pump that is used for pumping and the first permanent valve on a WBE) are used in conjunction with pumping operations, the following applies:

a) They shall be adequately anchored to prevent whipping, bouncing, or excess vibration, and to constrain all piping if a break should occur.
b) Precautions shall be taken and reviewed with relevant personnel to ensure that they are not damaged by dropped objects from cranes, trolleys, skidding systems etc.
c) Their RWP shall be equal to or exceed the maximum pumping pressure.
d) They shall be leak tested to a pressure exceeding maximum allowable pumping pressure, after installation and prior to use.
e) They should have sufficient ID to avoid erosion from the pumping operation.
f) A check valve shall be installed in each discharge line as close to the well connection point as possible. A bleed-off line between the check valve(s) and the production tree master valve should be installed to enable venting of trapped pressure.
g) They shall be equipped with a pressure relief valve at the pump set and checked for the maximum allowable pumping pressure. The relief valve should discharge into a non-hazardous location. (See subclause 14.7.1 a).)

14.7.4 Hard piping discharge lines

There are no additional requirements and guidelines to what is stated in 14.7.3.

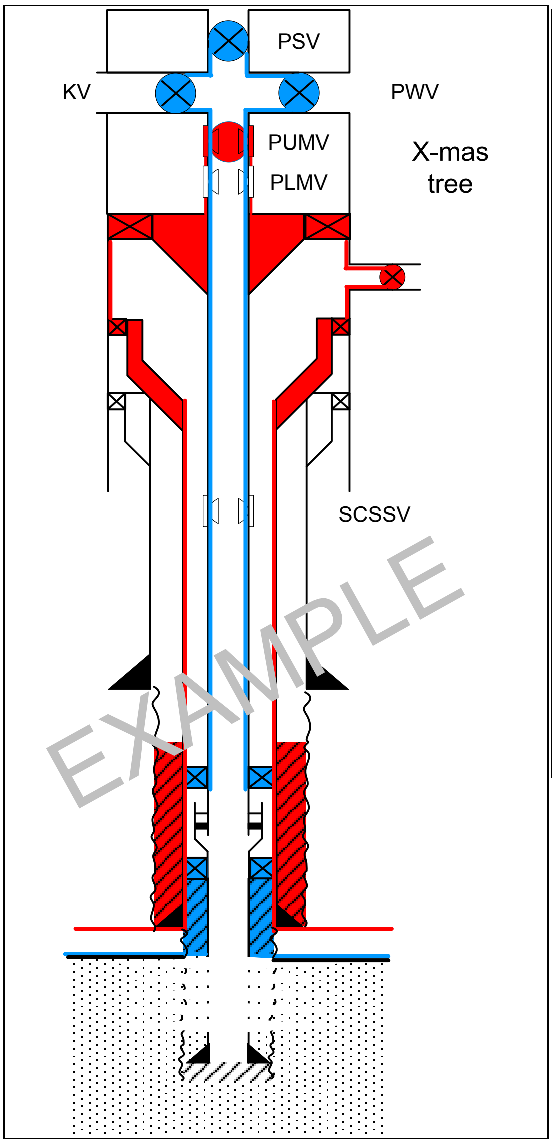
14.7.5 Flexible hose discharge lines

Flexible hoses shall:

a) be compatible with all anticipated fluids and any combination of these in addition to all physical loads it may be exposed to;
b) be used in compliance with manufacturers written instructions;
c) have a design safety factor for burst pressure that is 4 x RWP;
d) have integral fittings and a separate restraint system to prevent hose ends from uncontrolled movement if end fitting slips out of hose/crimp sleeve;
e) be protected from external abrasion.

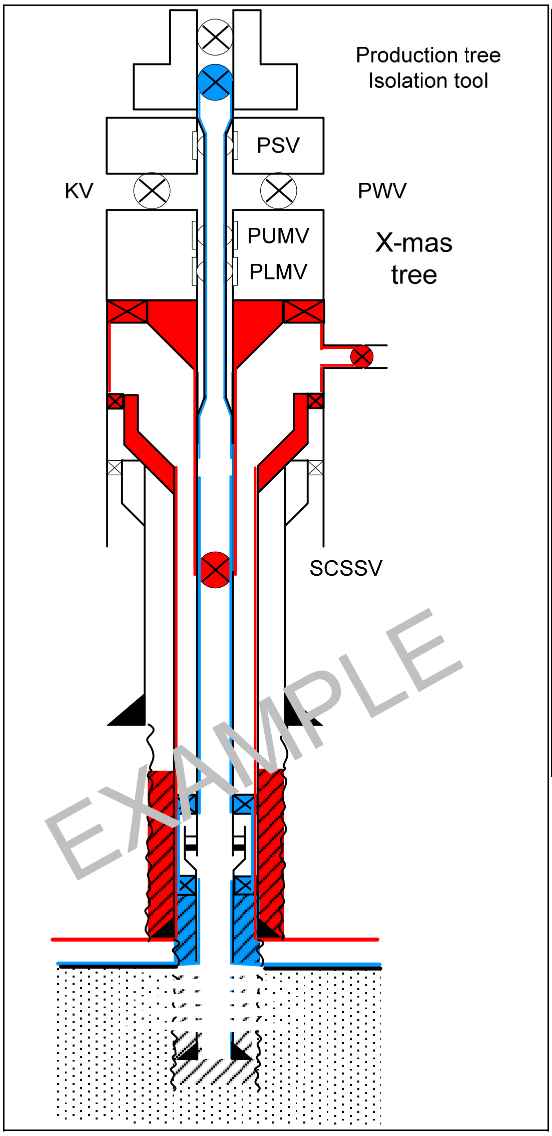
14.7.6 WBS examples

The following WBSs are examples and describe one possible solution for defining and illustrating well barrier envelopes.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Liner cement	22	
Liner	2	
Production packer	7	
Completion string	22	
Tubing hanger	10	
Surface production tree	33	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing hanger	10	
Surface production tree	33	

Figure 14.8.1 – Pumping through tubing – DHSV isolated



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Liner cement	22	
Liner	2	
Production packer	7	
Completion string	22	
Production tree isolation tool	23	
Secondary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing hanger	10	
Completion string	22	
DHSV	8	

Figure 14.8.2 – Pumping through tubing – production tree isolation tools installed

15 Well barrier elements acceptance tables

15.1 Table 1 – Fluid column

Features	Acceptance criteria	See
A. Description	This is the fluid in the wellbore.	NORSOK D-001
B. Function	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the wellbore that will prevent well influx/inflow (kick) of formation fluid.	
C. Design construction selection	1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed. 4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin. 5. Changes in wellbore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified. 2. Critical fluid properties, including density shall be within specifications.	
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. If there is a risk of lost circulation, lost circulation material should be available. 4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density. 5. Simultaneous well displacement and transfer to or from the fluid tanks should only be done with a high degree of caution, not affecting the active fluid system. 6. Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a “killsheet”.	
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well.	ISO 10414-1 ISO 10414-2
G. Common well barrier	None	

15.2 Table 2 – Casing

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide an isolation that stops uncontrolled flow of formation fluid or injected fluid between the casing bore and the casing annulus.	
C. Design construction selection	1. Casing/liner strings, including connections shall be designed to withstand all loads and stresses expected during the lifetime of the well (including all planned operations and potential well control situations). Any effects of degradations shall be included. 2. Minimum acceptable design factors shall be calculated for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. All load cases shall be defined and documented with regards to burst, collapse and tension/compression. 4. Casing design can be based on deterministic or probabilistic models. 5. Casing exposed to hydrocarbon flow potential shall have gas-tight threads. Exception: Surface casing which is exposed or can be potentially exposed to normal gradient shallow gas.	ISO 11960 ISO 13679 ISO 10405
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities. 3. The leak test of casing shall be performed either when cement is wet (immediately after pumping) or after cement has set up. No pressure testing should be performed while the cement is setting up.	
E. Use	Casing/liner should be stored and handled properly to prevent damage to pipe body and connections prior to installation.	
F. Monitoring	1. The A-annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall be monitored at regular intervals. 2. All casing strings shall be logged for wear after drilling if simulation indicates excessive wear which exceeds allowable wear based on casing design. Metal shavings should be collected by the use of ditch magnets.	
G. Common well barrier	1. During drilling operations with surface BOP, the annulus outside the current casing shall be monitored continuously and alarm levels be defined. 2. Actual status of the casing shall be known and confirmed capable of withstanding maximum expected pressure after expected wear. 3. Pressure test should include safety margin to cover expected wear after testing. 4. Magnet shall be in the mud return flowline to measure metal and assess changes in the nature of the metal filings. 5. If drilling through an old casing: a) Prior to drilling activity commences, casing wear log(s) should be run (calliper and/or sonic). The logs shall be verified by qualified personnel and documented. b) Logs that can identify localised (1 m interval between measurements) doglegs (gyro or similar) should be run.	

15.3 Table 3 – Drill string

Features	Acceptance criteria	See
A. Description	This element consists of drill pipe, heavy weight drill pipe and drill collars used as drill string or work string.	
B. Function	The purpose of the drill string as WBE is to prevent flow of formation fluid from its bore and to the external environment.	
C. Design construction selection	1. Dimensioning load cases shall be defined and documented. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear; fatigue and buckling shall be included in the design factors. 3. Drill pipe should be selected with respect to: a) make-up torque necessary to prevent make-up in the well; b) tool joint clearance and fishing restrictions; c) pumping pressure and ECD; d) abrasive formations; e) buckling resistance; f) hard banding and its influence on casing wear; g) metallurgical composition in relation to exposure to corrosive environment; h) fatigue resistance; i) HT: Strength reduction due to temperatures effects.	API RP 7G ISO 11961 API Spec 5DP API Bull 5C2 ISO 10424-1
D. Initial test and verification	1. Stable pump pressure when circulating fluid. 2. HPHT: The component of the drill string should be MPI inspected prior to HPHT mode status.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the drill string is located inside the BOP. 2. Drilling float valves should be installed in the drill string. In cement stingers, the float is optional.	API RP 7G
F. Monitoring	1. Pump pressure shall be continuously monitored for pressure anomalies during circulation. 2. Regular inspection and maintenance based on documented routines shall be conducted. 3. Visual checks for wear, washouts, thread damage and cracks should be conducted regularly.	
G. Common well barrier	The historical data of the drill pipe shall be evaluated, and the drill pipe shall be inspected to DS1 category 5. Drill pipe joints shall be selected based on an overall evaluation to minimise the risk of failure. Visual checks for wear, washouts, thread damage and cracks should be conducted for each trip.	TH Hill DS-1

15.4 Table 4 – Drilling BOP

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead connector and drilling BOP with kill/choke line valves.	NORSOK D-001
B. Function	The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the wellbore with or without tools/equipment through the BOP.	
C. Design construction selection	1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. A risk analysis shall be performed to decide the best BOP configuration for the location in question. The risk analysis should take the following into account: a) position of different ram types; b) choke and kill line access position; c) ability to hang off pipe and retain ability to close shear ram, including contingency closure of rams if available; d) ability to centralize pipe prior to closing shear ram; e) back-up shear ram. 3. The BOP WP shall exceed the WDP including a margin for killing operations. 4. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the wellbore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 5. When running non-shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non-shearable item. Other activities should be coordinated in order to minimize the overall risk level on the installation while running non-shearable items through the BOP. 6. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 7. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 8. There may be an outlet below the LPR. This outlet shall not be used as a choke line unless a proper risk analysis has been performed. The number of flanges shall be minimized. 9. HPHT: The BOP shall be furnished with surface readout pressure and temperature. 10. Deep water: a) The BOP shall be furnished with surface readout pressure and temperature. b) The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. c) Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) d) From a DP vessel it shall be possible to shear full casing strings and seal thereafter, by use of a combination of casing shear ram and blind shear ram. Otherwise, the casings should be run as liners.	NORSOK D-001 API Spec 53 API Spec 16RCD ISO 13533
D. Initial test and verification	See Annex A, Table .38. 1. Components shall be visually inspected for internal wear during installation and removal.	
E. Use	The drilling BOP elements shall be activated as described in the well control action procedures.	

Features	Acceptance criteria	See
F. Monitoring	See Annex A, Table .38.	
G. Common well barrier	1. Stress analysis due to UBD/MPD equipment/operations shall be performed. Effect of extra loads and tie-ins shall be analysed. 2. Visual inspections shall be done based on a predefined inspection frequency. 3. No operations causing excessive wear on the BOP shall be planned.	

15.5 Table 5 – Wellhead

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead body with annulus access ports and valves, seals and casing hangers with seal assemblies.	
B. Function	Its function is to provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or tree and to prevent flow from the bore and annuli to formation or the environment.	
C. Design construction selection	1. The WP for each section of the wellhead shall exceed the maximum well shut-in pressure the section can become exposed to plus a defined safety factor. 2. For dry wellheads, there shall be access ports to all annuli to facilitate monitoring of annuli pressures and injection/bleed-off of fluids. 3. For subsea wellheads, there shall be access to the casing by tubing annulus to facilitate monitoring of annulus pressure and injection /bleed-off of fluids. 4. Wellheads that will be used as a flow conduit for continuous or intermittent production from or injection into annulus/annuli, shall be designed and qualified for such functions without impairing the well integrity function of the wellhead. For gas lift applications, gas expansion and the resulting temperature should be addressed. 5. The casing hanger shall be locked down to ensure seal integrity during normal working loads as well as well control situations.	ISO 10423
D. Initial test and verification	6. The wellhead body (or bodies and seals), annulus ports with valves and the casing seal assemblies shall be leak tested to design pressure for the specific hole section or operation.	
E. Use	A wear bushing should be installed in the wellhead when movement of tools/work-strings can inflict damage to seal areas.	
F. Monitoring	1. Annulus valves shall be leak and function tested frequently. 2. The A-annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 3. Movements in the wellhead during work over (shut-in/start-up) should be observed and compared to design values. 4. Accessible seals (land- and platform wells) shall be periodically leak tested, first time within 1 year then at a maximum frequency of 2 years. 5. Periodically inspections for sign of external leaks or deterioration based on installation risk (visual and ROV for subsea). The frequency shall as a minimum be yearly for subsea wells, if not otherwise defined in a risk assessment.	
G. Common well barrier	1. Stress analysis due to UBD/MPD equipment/operations shall be performed. Effect of extra loads and tie-ins shall be analysed. 2. Visual inspections shall be done based on a predefined inspection frequency 3. During drilling activities with a surface BOP, the annulus outside the current casing shall be monitored continuously and alarm levels be defined.	

15.6 Table 6 – Intentionally left blank

15.7 Table 7 – Production packer

Features	Acceptance criteria	See
A. Description	This element consists of a body with an anchoring mechanism to the casing/liner, and an annular sealing element which is activated during installation.	
B. Function	Its purpose is to: 1. provide a seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer; 2. prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string.	
C. Design, construction and selection	1. The production packer shall be qualified and tested in accordance to principals given in recognized standards, i.e. ISO14310 V1 as minimum and V0 if the well contains free gas at the setting depth. The production packer shall be qualification tested in unsupported, non-cemented casing. 2. The setting depth shall be such that any leak through the casing below the packer, will be contained by the well barrier system outside the casing. The formation integrity and any annulus seal (e.g. cement) shall be able to withstand the pressures or temperatures expected throughout the lifetime of the well. 3. It shall be permanently set (meaning that it shall not release by upward or downward forces), with ability to sustain all known loads. 4. Mechanically retrievable production packers shall be designed to protect against unintentional activation. 5. The packer (body and seal element) shall withstand maximum differential pressure, which should be based on the highest of: a) pressure testing of tubing hanger seals; b) reservoir-, formation integrity- or injection pressures less hydrostatic pressure of fluid in annulus above the packer; c) shut-in tubing pressure plus hydrostatic pressure of fluid in annulus above the packer less reservoir pressure; d) collapse pressure as a function of minimum tubing pressure (plugged perforations or low test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present.	ISO 14310
D. Initial test and verification	It shall be leak tested to the maximum differential pressure in the direction of flow, if feasible. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum differential pressure, providing that ability to seal both directions can be documented.	
E. Use	Running of intervention tools shall not impair its ability to seal nor inadvertently cause it to be released.	
F. Monitoring	Sealing performance shall be monitored through continuous recording of the A-annulus pressure measured at wellhead level.	
G. Common well barrier	None	

15.8 Table 8 – Downhole safety valve

Features	Acceptance criteria	See
A. Description	This element consists of a tubular body with a close/open mechanism that seals off the tubing bore.	
B. Function	Its purpose is to prevent flow of hydrocarbons or fluid up the tubing.	
C. Design, construction and selection	1. It shall be positioned minimum 50 m below seabed. 2. The setting depth shall be dictated by the pressure and temperature conditions in the well with regards to forming of hydrates and deposition of wax and scale. 3. It shall be: a) surface controlled; b) fail-safe closed. 4. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 5. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus. 6. The DHSV should pass 5 slam closures where minimum 2 (two) slam closures are at the maximum theoretical production rate of the well where the system is to be installed. This to prove the DHSV is designed for and can withstand the force generated by the slam closure without deformation of vital parts	API Spec 14A/ISO10432 API RP 14B
D. Initial test and verification	It shall be tested with both low and high differential pressure in the direction of flow. The low pressure test shall be maximum 70 bar (1000 psi).	
E. Use	When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months; d) test evaluation period is volume and compressibility dependent and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 30 min. 2. Acceptance of downhole safety valve tests shall meet the following ANSI/API RP 14B requirements: a) 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas; b) 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. *4.* The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	API RP 14B ISO 10417
G. Common well barrier	None	

15.9 Table 9 – Annulus safety valve

Features	Acceptance criteria	See
A. Description	The element consists of a tubular and an annulus sealing element which can be activated to seal off the annular wellbore.	
B. Function	Its purpose is to: a) prevent flow of media up the A-annulus; b) provide a pressure seal in the A-annulus between the casing and the tubing.	
C. Design, construction and selection	1. It shall be designed and tested in accordance with API RP 14B. 2. It shall be located minimum 50 m below seabed. If annulus is used for production, the setting depth shall be determined by the possibility of forming of hydrates and deposition of wax and scale. 3. It shall be subject to flow erosion resistance verification for all relevant fluids, if it will become exposed to high production/injection rates. 4. When part of the annulus safety system, the packing element shall comply with the same requirements as for a production packer. 5. It shall have a WP which exceeds the WDP. The WDP should be based on reservoir pressure less gas gradient below packer and evacuated A-annulus above. 6. It shall be: a) surface controlled; b) fail-safe closed. 7. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 8. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus.	API Spec 14A API RP 14B ISO 14310
D. Initial test and verification	It shall be leak tested in the direction of flow to: 1. a low pressure which shall maximum be 70 (~1000 psi) bar; 2. WDP.	
E. Use	When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	

Features	Acceptance criteria	See
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months; d) the test evaluation period is dependent upon volume and compressibility and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 30 min. 2. Acceptance of downhole safety valve tests shall meet the following API RP 14B requirements: a) 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas; b) 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. The valve shall be periodically function tested including the emergency shutdown function based on reliability analysis but as a minimum yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	API RP 14B ISO 10417
G. Common well barrier	None	

15.10 Table 10 – Tubing hanger

Features	Acceptance criteria	See
A. Description	This element consists of a body, seals, feed throughs, and bore(s) which may have a tubing hanger plug profile.	
B. Function	Its function is to: a) support the weight of the tubing; b) prevent flow from the bore and to the annulus; c) provide a hydraulic seal between the tubing, wellhead and tree; d) provide a stab-in connection point for bore communication with the tree; e) provide a profile to receive a BPV or plug to be used for nippling down the BOP and nippling up the tree.	
C. Design, construction and selection	1. The tubing hanger shall be designed, qualified, tested, and manufactured in accordance with recognized standards. 2. When used in conjunction with annulus injection (gas lift, cutting injection, etc.) any low temperature cycling effects need to be taken into consideration.	ISO 13533 ISO 13628-4 ISO 10423
D. Initial test and verification	The locking of the tubing hanger shall be verified by overpull and/or pressure from below exceeding the string weight. All seals shall be leak tested to the WDP, and should be tested in the direction it is designed to hold pressure.	
E. Use	None	
F. Monitoring	1. Continuous monitoring of A- annulus pressure. 2. Accessible seals (land- and platform wells) shall be pressure tested at installation, within 1 year after installation and then at a maximum frequency of 2 years.	
G. Common well barrier	None	

15.11 Table 11– Tubing hanger plug

Features	Acceptance criteria	See
A. Description	This element consists of an equalising plug with a locking device and a seal between the bore of the tubing hanger and the body of the plug.	
B. Function	Its function is to provide a pressure seal in the bore of the tubing hanger, e.g. during BOP/tree removal and installation.	ISO 14310
C. Design, construction and selection	1. The plug shall be designed for the maximum differential pressure. Installation and test loads shall also be considered. 2. Wellbore fluids and conditions (brine, H_2S, CO_2, temperature, hydrate etc.) shall be considered. 3. It shall comply with leak criteria given in ISO 14310 V1 for design validation, V0 if free gas is present. 4. The plug (including prong, if used) shall not extend up above the tubing hanger body if used as a WBE. For subsea HXT, the plug shall be designed to be an integral part of the HXT with the following additional requirements: 1. The plug shall be designed for the maximum differential pressure including any thermal loads caused by trapped volumes and fluid expansion. 2. The compatibility with fluids and gas during life of well (brines, H_2S, CO_2, stimulation or chemical treatment fluids, reservoir souring, etc.) shall be verified. 3. The plug shall have metal-to-metal sealing and comply with leak criteria given in ISO 14310 V0.	
D. Initial test and verification	1. The tubing hanger plug shall be tested in the flow direction. When this is not possible, it should be tested from above. 2. The tubing hanger plug shall be tested to maximum differential pressure.	
E. Use	The tubing hanger plug shall only be classified as a WBE during BOP or tree disconnect.	
F. Monitoring	Regular monitoring of pressure above plug.	
G. Common well barrier	None	

15.12 Table 12 – Wellhead annulus access valve

Features	Acceptance criteria	See
A. Description	This element consists of an annulus isolation valve(s) and valve housing(s) connected to the wellhead.	
B. Function	Its function is to provide ability to monitor pressure and flow to/from the annuli.	
C. Design, construction and selection	1. The housing shall have a material grade and specification compatible with the materials which it is attached to. 2. The housing and valve(s) shall be fire resistant. 3. The access point and valve shall have a pressure rating equal to or higher than the wellhead/tree system. 4. The valve shall be: a. designed, qualified, tested and manufactured in accordance with recognized standards; b. gas tight. 5. The access point and valve shall have a pressure rating equal to or higher than the wellhead/tree system. 6. When used in conjunction with annulus injection (gas lift, cuttings injection, etc.) the valve shall be: a) surface controlled; b) automatically operated; and c) fail-safe closed. Low temperature cycling effects should to be taken into consideration.	ISO 10423/API Spec 6A ISO 15156 API Spec 17D ISO 10497/API Spec 6FA
D. Initial test and verification	The valve shall be tested in the direction annulus to process piping.	
E. Use	The valve shall normally be open for monitoring purposes, with another valve isolating the access to the platform system, which should only be opened for the purpose of adjusting the annulus pressure.	

Features	Acceptance criteria	See
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level. 2. The test evaluation period is dependent upon volume and compressibility and shall be held for a period that will give measurable pressure change for the allowed leak rate, minimum 10 min. 3. Manual valves exposed to injection or production fluids shall be leak tested every 6 months. For passive annuli, the manual valves shall be tested yearly. 4. Injection valves shall be leak tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months. 5. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 6. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	
G. Common well barrier	None	

15.13 Table 13 – Coiled tubing

Features	Acceptance criteria	See
A. Description	This element consists of a continuous milled tubing string that is spooled on to a CT reel.	
B. Function	The function of the CT string is to prevent flow of formation fluid from its bore to the external environment.	
C. Design, construction and selection	1. Dimensioning load cases shall be defined and documented. 2. Minimum acceptable design factors shall be defined (80 % of minimum yield). Estimated effects of temperature, corrosion, wear, fatigue, and buckling shall be included in the design factors. 3. Coiled tubing should be selected with respect to: a) yield strength; b) pump rate; c) length; d) weight; e) burst pressure; f) collapse pressure.	API RP 5C7
D. Initial test and verification	1. Leak test after initial rig-up. 2. Leak test to WHP on following runs.	
E. Use	An end-connector with a double/dual check valve assembly or a fail-safe closing device to prevent unintentional flow of formation fluid into the CT string shall be used.	
F. Monitoring	1. Pump pressure and wellhead pressure shall be continuously monitored during the operation. 2. Regular inspection and maintenance based on documented routines shall be conducted. 3. Visual or continuous inspection during operation. 4. Fatigue and remaining lifetime shall be recorded.	NORSOK D-002
G. Common well barrier	None	

15.14 Table 14 – Coiled tubing BOP

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with rams, a kill inlet connection and riser connections.	NORSOK D-002
B. Function	The function of the CT BOP is to prevent flow form the wellbore in case of leakage in the CT string or stripper. It shall be able to close in and seal the wellbore with or without the CT string through the BOP. The CT BOP is a back-up WBE to the stripper in the primary well barrier.	
C. Design, construction and selection	1. The CT BOP shall be designed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT and seal off the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented. 4. The pipe ram shall be able to provide a seal on the CT annulus. 5. The slip ram shall be able to grip and hold the CT string. 6. A kill inlet port shall be located between the shear/seal ram and the pipe ram. It shall be possible to pump heavy fluid through the CT string after the BOP has been activated.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The CT BOP elements shall be activated as described in the well control action procedures (contingency procedures should be established).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak and functional test, minimum every 14 days.	
G. Common well barrier	None	

15.15 Table 15 – Coiled tubing check valves

Features	Acceptance criteria	See
A. Description	This element consists of a body with a double/dual flapper check valve or a failsafe closing device and a connector for mounting to the end of the CT string.	
B. Function	The function of the CT check valves is to prevent unintentional flow of formation fluid into the CT string.	
C. Design, construction and selection	1. The check valves shall be designed to withstand all expected downhole forces and conditions. 2. The pressure rating shall exceed the maximum operating pressure. 3. The check valves shall be provided with dual seals in the bore and provide internal and external sealing on the connections towards the CT string. 4. Provisions shall be made for pumping balls through the CT check valves.	NORSOK D-002
D. Initial test and verification	1. Leak test prior to connecting to the CT string. 2. Inflow test prior to each run in hole.	
E. Use	The end-connector and CT check valves are connected directly to the end of the CT string.	
F. Monitoring	Periodic inflow test	
G. Common well barrier	None	

15.16 Table 16 – Coiled tubing safety head

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with a shear/seal ram and riser connections.	
B. Function	The function of the CT safety head (BOP) is to prevent flow from the wellbore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the wellbore with or without CT through the BOP. The safety head is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	1. The CT safety head shall be designed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT or wireline and seal the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The CT safety head shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak and functional test, minimum every 14 days.	
G. Common well barrier	None	

15.17 Table 17 – Coiled tubing strippers

Features	Acceptance criteria	See
A. Description	This element consists of a body with a sealing element and a riser connection.	
B. Function	The function of the stripper is to provide the primary pressure seal between the wellbore and the atmosphere while allowing the CT string to move into or out of the well. The stripper is the upper closure device in the primary well barrier.	
C. Design, construction and selection	1. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations. 2. It shall be able to maintain a pressure seal with the CT string static, even if the power supply is lost.	NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high-pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	1. The hydraulic pressure shall be sufficient to maintain a dynamic pressure seal, but as low as possible to avoid excessive friction, wear and collapsing the CT string. 2. The upper stripper element shall be used as the primary stripper.	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak and functional test, minimum every 14 days.	
G. Common well barrier	None	

15.18 Table 18 – Snubbing check valves

Features	Acceptance criteria	See
A. Description	The element consists of a body with a dual flapper check valve for mounting to the end of the workstring.	
B. Function	The function of the snubbing check valves is to prevent unintentional flow of formation fluid into the snubbing string.	
C. Design, construction and selection	1. It shall be designed to withstand all expected downhole forces and conditions. 2. Working pressure rating shall be equal to the maximum operating pressure. 3. It shall be provided with dual seals in the bore and provide internal and external sealing on the connections towards the snubbing string. 4. Provisions shall be made for pumping balls through the snubbing check valves. 5. Both check valves shall be installed in the BHA/work string prior to opening up the well.	NORSOK D-002
D. Initial test and verification	1. Low- and high-pressure leak test prior to connecting to the snubbing string. 2. Inflow test prior to each run in hole.	
E. Use	The snubbing check valves are connected directly to the end of the snubbing string and above BHA.	
F. Monitoring	Periodic inflow test	
G. Common well barrier	None	

15.19 Table 19 – Snubbing BOP

Features	Acceptance criteria	See
A. Description	The element consists of riser and snubbing BOP with kill/choke line valves. The snubbing BOP normally consists of one lower pipe ram, one shear blind ram, one upper pipe ram and one annular preventer.	NORSOK D-002
B. Function	The function of the snubbing BOP is to prevent flow form the wellbore in case of leakage in the snubbing string or stripper. **Annular** The annular preventer is also a stripping device and is capable of sealing around objects such as drill collars and un-perforated guns. It is used as a back-up to the stripper rubber, pipe- and stripper rams. **Upper pipe ram** The purpose of the upper pipe ram is to maintain well control in the event of the failure of, or maintenance on, the highest primary closure device, i.e. a back-up for either the stripper rubber or the stripping rams. When closing the pipe ram, or variable ram, circulation can be performed through the kill and choke lines below the shear/blind ram. The pipe ram is not designed for stripping. **Shear/blind ram** The shear/blind ram is part of the back-up system in the primary well barrier. It can be the first option to use if cutting of the tubular is necessary. **Lower pipe ram** The purpose of the lower pipe ram is to maintain well control in the event of the failure of, or maintenance to, active elements in the primary well control system, i.e. a back-up element to the stripping rams or the stripper rubber. In an emergency the lower pipe ram can be used as a hang off mechanism below the shear/blind ram. The pipe ram is not designed for stripping.	
C. Design, construction and selection	1. It shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations. 3. It shall be documented that the shear blind ram can shear and seal the wellbore thereafter. If the manufacturer cannot document it, a qualification test shall be performed and documented. 4. The pipe ram shall be able to provide a seal on the snubbing annulus. 5. The seal/slip ram if used shall be able to seal and grip and hold the tubular. 6. A kill/choke inlet port shall be located between the shear blind ram and the lower pipe ram. It shall be possible to pump heavy fluid through the snubbing string after the BOP has been activated. 7. When using tapered tubulars there should be one fixed ram for each size.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The snubbing BOP elements shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	Periodic visual inspection for external leaks Periodic leak and functional test, minimum every 14 days	
G. Common well barrier	None	

15.20 Table 20 – Snubbing stripper

Features	Acceptance criteria	See
A. Description	The stripper consists of a rubber element inside a housing (stripper bowl). The element provides a seal towards the atmosphere based on the following principle: the workstring OD is larger than the stripper rubber ID. The system is based on wellbore pressure assist.	
B. Function	The function of the stripper is to provide the primary pressure seal between the wellbore and the atmosphere while allowing the snubbing string to move into or out of the well.	
C. Design, construction and selection	1. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations. 2. The pipe OD and the well pressure to be taken into account when determining if the stripper rubber can be used to avoid ram-to-ram stripping.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Perform leak test after initial installation. 2. Perform low- and high pressure leak tests after installation. 3. Perform leak test of connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The pipe OD and the well pressure are taken into account when determining if the stripper rubber can be used to avoid ram-to-ram stripping.	
F. Monitoring	Periodic visual inspection for external leaks	
G. Common well barrier	None	

15.21 Table 21 – Snubbing safety head

Features	Acceptance criteria	See
A. Description	The element consists of a connector and a shear/seal ram.	
B. Function	The function of the snubbing safety head (BOP) is to prevent flow form the wellbore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the wellbore with or without the workstring through the BOP. The safety head is the upper closure device in the secondary well barrier	
C. Design, construction and selection	1. The snubbing safety head shall be constructed in accordance with NORSOK D-002. 2. The pressure rating shall exceed the maximum differential pressure that it can become exposed to, including a margin for killing operations It shall be documented that the shear/seal ram can shear the workstring, CT or wireline and seal the wellbore thereafter. If the manufacturer cannot document this, a qualification test shall be performed and documented. 3. The safety head shall only be closed in an emergency and during testing. As there is normally no gauge between the safety head and the swab valve these two valves should not be in closed position at the same time. 4. The safety head shall be flanged close to the tree.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low- and high leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The snubbing safety head shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	Periodic visual inspection for external leaks Periodic leak and functional test, minimum every 14 days	
G. Common well barrier	The snubbing safety head (body, sealing rams and lower connection) will normally be defined as a common WBE. Risk reducing measures should be established and implemented.	

15.22 Table 22 – Casing cement

Features	Acceptance criteria	
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation. NOTE The shoe track cement is covered in table 24.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A cement program shall be issued for each cement job, minimum covering the following: a) casing/liner centralization and stand-off to achieve pressure and sealing integrity over the entire required isolation length; b) use of fluid spacers; c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to cement setting up; d) the risk of lost returns and mitigating measures during cementing. 2. For critical cement jobs, HPHT conditions and complex/foam slurry designs the cement program shall be verified independent (internal or external), qualified personnel. 3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development. 4. The properties of the set cement shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure. 5. Cement slurries used for isolating sources of inflow containing hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S, if present. 6. Planned casing cement length: a) Shall be designed to allow for future use of the well (sidetracks, recompletions, and abandonment). b) **General**: Shall be minimum 100 m MD above a casing shoe/window. c) **Conductor**: Should be defined based on structural integrity requirements. d) **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be at surface/seabed. e) **Production casing/liner**: Shall be minimum 200m MD above a casing shoe. If the casing penetrates a source of inflow, the planned cement length shall be 200m MD above the source of inflow. a. Note: If unable to fulfil the requirement when running a production liner, the casing cement length can be combined with previous casing cement to fulfil the 200m MD requirement.	API RP 10B ISO 10426-1

Features	Acceptance criteria	
D. Initial verification	Cement should be left undisturbed until it has reached sufficient compressive strength. 1. The cement sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out. 2. The cement length shall be verified by one of the following: a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented. b) 100 % displacement efficiency based on records from the cement operation (volumes pumped, returns during cementing, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. In case of losses, it shall be documented that the loss zone is above planned TOC. Acceptable documentation is job record comparison with similar loss case(s) on a reference well that has achieved sufficient length verified by logging. c) In the event of losses, it is acceptable to use the PIT/FIT or LOT as the verification method only if the casing cement shall be used as a WBE for drilling the next hole section. (This method shall not be used for verification of casing cement as a WBE for production or permanent abandonment.) 3. Critical casing cement shall be logged and is defined by the following scenarios: a) the production casing/production liner when set into/through a source of inflow with hydrocarbons; b) the production casing/production liner when the same casing cement is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock. 4. Actual cement length for a qualified WBE shall be: a) above a potential source of inflow/ reservoir; b) 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval. c) 2 x 30m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier. d) The formation integrity shall exceed the maximum expected pressure at the base of each interval. e) For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the upper most injection point to 30 m MD above top reservoir verified by bonding logs.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the casing cement shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet should be observed regularly.	
G. Common well barrier	It is not acceptable for use as a common WBE. When casing cement is a part of the primary and secondary well barriers, this is defined as critical casing cement and the criteria in D. Initial verification applies.	

15.23 Table 23 – Tree isolation tool

Features	Acceptance criteria	See
A. Description	The tree isolation tool is a temporary arrangement installed in the tree to isolate the tree and tubing hanger from treating pressure and fluids.	
B. Function	The function of the tree isolation tool is to: a) isolate the tree and tubing hanger from treating pressure when maximum treating pressures could exceed the maximum rated WP for the tree/tubing hanger; or b) isolate the tree from abrasive fluids.	
C. Design, construction and selection	1. The WP of the tree isolation tool shall as a minimum exceed the maximum treating pressure, plus 10 %. 2. The tree isolation tool shall be flanged to the tree with metal to metal seals. 3. The tree isolation tool re-tract system shall be remote operated. 4. The tree isolation tool shall have double valve system on the fluid inlet. Both valves shall be flanged to the tree isolation tool with metal to metal seals. 5. The inner valve shall be hydraulically remote operated. 6. The seal stack which seals inside the tubing shall have a WP equal to the tree isolation tool in the specific tubing ID it is designed to seal against.	
D. Initial verification	1. It shall be documented that the tree isolation tool has been leak tested to 50 % above the RWP after last inspection. 2. After installation on the tree the tree isolation tool shall be leak tested to tree WP against upper or lower master valve. 3. Stable pressure in annulus between the tree isolation tool and the tree after pressure bled off in the tree.	
E. Use	1. Discharge treating line shall have sufficient length such that the tree isolation tool seal stack can be deployed and retracted with two well barriers in place. 2. Wing valve on the tree shall be open after sealing the tree isolation tool seal stack and a bleed line shall be discharged to a non-hazardous location. The seal stack seal should be monitored throughout the operation.	
F. Monitoring	Annulus between the tree isolation tool and the tree shall be continuously monitored for pressure build up indicating leaking seal stack on the tree isolation tool.	
G. Common well barrier	None	

15.24 Table 24 – Cement plug

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>
1. A program shall be issued for each cement plug installation.
2. For critical cement jobs, HPHT conditions and complex slurry designs the cement program should be verified by independent (internal or external) qualified personnel.
3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.
4. Cement slurries used in plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (CO_2, H_2S).
5. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
6. It shall be designed for the highest differential pressure and highest downhole temperature expected including installation and test loads.
7. A minimum cement batch volume shall be defined to ensure that a homogenous slurry can be made, taking into account all sources of contamination from mixing to placement.
8. The minimum cement plug length shall be:
<table>
<tr><td>Open hole cement plugs</td><td>Cased hole cement plugs</td><td>Open hole to surface plug (installed in surface casing)</td></tr>
<tr><td>100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.</td><td>50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
9. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
10. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
a. The cement plug shall extend 50m into the casing.
b. It shall be set on a foundation (TD or a cement plug(s) from TD). The cement plug(s) shall be placed directly on top of one another.
11. A casing/liner shall have a shoe track plug with a 25 m MD length.
</td><td>API Spec 10A Class ‘G’</td></tr>
</table>

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial verification</td><td>
1. Cased hole plugs should be tested either in the direction of flow or from above.
2. For the shoe track to be used as a WBE, the following applies:
a. the bleed back volume from placement of casing cement shall not significantly exceed the calculated volume; and
b. it shall be either pressure tested and supported by overbalanced fluid (see EAC 1) or inflow tested.
3. The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
4. The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
5. The plug shall be verified by:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging.</td></tr>
<tr><td>Cased hole</td><td>Tagging.
Pressure test, which shall:
a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and
b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.</td></tr>
</table>
</td><td></td></tr>
<tr><td>E. Use</td><td>None.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>If one continuous cement plug (same cement operation) is defined as part of the primary and secondary well barriers, it shall be verified by drilling out the plug until hard cement is confirmed.
1. An open hole cement plug extended into the casing shall be pressure tested.</td><td></td></tr>
</table>

15.25 Table 25 – Completion string

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string is to provide a conduit for formation fluid from the reservoir to surface or vice versa, and prevent communication between the completion string bore and the A-annulus.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have ISO13679 CAL III connections or CAL IV connections when exposed to free gas during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to: a) tensile and compression load exposure; b) burst and collapse criteria; c) tool joint clearance and fishing restrictions; d) tubing and annular flow rates; e) abrasive composition of fluids; f) buckling resistance; g) metallurgical composition in relation to exposure to formation or injection fluid; h) Strength reduction due to temperatures effects.	ISO 11960/API Spec 5CT ISO 13679
D. Initial test and verification	Pressure testing to WDP.	
E. Use	None	
F. Monitoring	Pressure integrity is monitored through the annulus pressure.	
G. Common well barrier	None	

15.26 Table 26 – Surface high pressure riser

Features	Acceptance criteria	See
A. Description	The element is the riser including connectors and seals connecting the drilling BOP to the wellhead.	
B. Function	Its function is to act as an extension of the drilling BOP on platforms where the BOP and wellhead are positioned at different levels and thus prevent flow from the bore to the environment.	
C. Design construction selection	1. The pressure rating shall be WDP including a margin for killing operations. 2. All sealing elements shall be resistant to maximum estimated exposure temperature and fluid system used. 3. Connectors shall be of a gas tight design for the expected loads.	ISO 13533 API RP 53
D. Initial test and verification	1. Shall be leak tested to maximum shut-in pressure for the specific hole section or operation. 2. Components shall be visually inspected for internal wear during installation and removal.	
E. Use	Shall be maintained, inspected and installed according to established procedures.	
F. Monitoring	Shall be leak tested if reinstalled.	
G. Common well barrier	1. Stress analysis due to UBD/MPD equipment/operations shall be performed. Effect of additional loads and tie-ins shall be analysed. 2. Visual inspections shall be done based on a predefined inspection frequency.	

15.27 Table 27 – Well test string

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the well test string as WBE is to provide a conduit for formation fluid from the reservoir to surface.	
C. Design, construction and selection	1. The components (pipe and threads) shall be gas tight. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, wear, fatigue and buckling shall be included in the design factors. 5. Pipe should be selected with respect to: a) tool joint clearance and fishing restrictions; b) flow performance in regard to production / injection rates; c) buckling resistance; d) metallurgical composition in relation to exposure to reservoir or other corrosive environment; e) fatigue resistance; f) HPHT: Strength reduction due to temperatures effects.	NORSOK D-SR-007
D. Initial test and verification	1. Pressure testing to WDP. 2. Thread inspection should be carried out by an independent third party. 3. HPHT: The element should be subjected to non-destructive examination.	
E. Use	Stab-in safety valve for all type of connections exposed at the drill floor shall be readily available when the drill stem test string is located inside the BOP.	
F. Monitoring	Pressure integrity is monitored by independence of the annulus pressure.	
G. Common well barrier	None	

15.28 Table 28 – Mechanical tubular plugs

Features	Acceptance criteria	See
A. Description	This element consists of a body with a locking or anchoring device and a seal between the bore of the casing/tubing and the plug body. This is a mechanical plug set in a profile or anywhere inside steel conduits (casing/tubular).	
B. Function	The purpose of the plug is to prevent flow of formation fluids and resist pressure from above or below, inside tubulars and in the annulus space between concentric positioned tubulars.	
C. Design, construction and selection (rating, capacity, etc.)	1. The mechanical plug shall be designed and qualified to withstand maximum differential pressure, minimum and maximum temperatures, number of pressure and temperature cycles, number of settings, well medium, life time expectations and all loads it will be exposed to during the installation time. 2. Down hole fluids and conditions (temperature, H_2S, CO_2, etc.) shall be considered in estimating the life time of the plug. 3. The plug shall comply with ISO 14310, as follows: a) Grade V1 for design validation; b) Grade Q1 for quality control. 4. The plug shall be designed such that pressure can be equalized across the plug in a controlled manner, if removed mechanically or by drilling out. 5. Inadvertent release of the plug by mechanical motion/impact shall not be possible. 6. The plug is not accepted as a WBE alone in permanent plugging of wells or branches of wells, where integrity in an eternal perspective is required. 7. It shall only be installed in a tubular section of the well which is cemented or supported by sufficient wall thickness to withstand loads from the plug.	ISO 14310
D. Initial verification and verification	It shall be leak tested to the maximum differential pressure in the direction of flow, if feasible. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum differential pressure, providing the ability to seal in both directions can be documented.	
E. Use	The plug shall be set as close as possible to the source of inflow and set at a depth where the hydrostatic pressure above the plug balances the pressure under the plug.	
F. Monitoring	Plug integrity shall be monitored regularly if access is available.	
G. Common well barrier	None	

15.29 Table 29 – Completion string component

Features	Acceptance criteria	See
A. Description	These elements consist of a housing with a bore. The completion string component is designed to prevent undesired communication between the completion string bore and the A-annulus.	
B. Function	Its purpose may be to provide support to the functionality of the completion, e.g. gas-lift or side pocket mandrels with valves or dummies, nipple profiles, gauge carriers, control line with seals/connections, etc.	
C. Design, construction and selection	1. The components (pipe and threads) shall have ISO13679 CAL III connections or CAL IV connections when exposed to free gas during its lifetime. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. The component should be designed/selected with respect to: a) burst and collapse criteria; b) tensile and compression load exposure; c) OD clearance and fishing restrictions; d) tubing (and annular) flow rates, also including erosion effects; e) metallurgical composition in relation to exposure to formation, injection or annulus fluid; f) odd shaped assemblies in casting material shall be subject to finite element analysis; g) Strength reduction due to temperatures effects. 4. Valves in the completion string above the production packer shall be qualified and tested in accordance to the leak criteria given in ISO 14310. V1 for design validation or V0 if free gas at depth.	ISO 13679 ISO 14310 ISO 10432/API Spec 14A ISO 10417 API RP 14B API Spec 11V1 ISO 17078-2
D. Initial test and verification	1. Pressure testing to WDP. 2. The valves shall be tested with both low and high differential pressure in the direction of flow. The low pressure test shall be maximum 70 bar (~1000 psi).	
E. Use	Running of intervention tools shall not accidentally change a functionality of the tool.	
F. Monitoring	1. Pressure monitoring of annuli, control/injection lines. 2. Gas lift valves and chemical injection valves shall be periodically tested according to EAC 8.	
G. Common well barrier	None	

15.30 Table 30 – Snubbing string

Features	Acceptance criteria	See
A. Description	This element consists of a string with jointed tubular.	
B. Function	The function of the snubbing string is to prevent flow of formation fluid from its bore to the external environment.	
C. Design, construction and selection	1. Dimensioning load cases shall be defined and documented. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. Snubbing string design basis, premises and assumptions. The following should be considered for the design of a snubbing string: a) weight; b) over pull; c) wellbore condition; d) hydraulically applied loads; e) transition point; f) maximum length; g) buckling; h) fatigue. 4. For snubbing operations the type of connection to be used above the check valves should be gas tight and have metal-to-metal seals. The seals should withstand internal and external pressure.	ISO 11960 NORSOK D-002
D. Initial test and verification	1. Leak test after initial rig-up. 2. Leak test to maximum WHP on following runs. 3. The plug for the nipple profile shall be leak tested to high and low pressure for 5 min to 10 min "on stump" before first run. It is not required to repeat this test if same equipment is used on later runs during the same operation.	
E. Use	1. A double / dual check valve assembly or a fail-safe closing device to prevent unintentional flow of formation fluid into the snubbing string shall be used. 2. A nipple profile shall be installed in the BHA to be used for internal well control if the check valves fail, i.e. back-up to the check valves.	
F. Monitoring	1. Pump pressure and wellhead pressure shall be continuously monitored during the operation. 2. Maintenance and certification of used tubular goods. Tubular goods (including end connections and any end connection - pipe body transition area/upset) shall be maintained and recertified to a specified minimum condition based on documented procedures. Procedures shall as a minimum cover the following: a) Tubular goods shall be free of defects that may jeopardize the certified minimum condition of the tubular goods. b) Minimum effective wall thickness and extent of reduced wall thickness, internally, externally or as a combination, at any location of the tubular goods shall be known and documented. c) End connections shall fulfil the design owner's requirements with regards to inspection, minimum acceptable condition, repair and maintenance. End connection compatibility: When compatible end connections designs are being used, compatibility shall be certified by all relevant end connection design owners.	NORSOK D-002
G. Common well barrier	None	

15.31 Table 31 – Sub-sea tree

Features	Acceptance criteria	See
A. Description	1. Subsea horizontal tree consists of a housing with bores that are fitted with production and annulus master valves, crown plugs, flow valves and crossover valves. 2. Subsea vertical tree consists of a housing with bores that are fitted with production and annulus master valves, swab or crown plug and flow valves.	
B. Function	Its function is to: a) provide a flow conduit for hydrocarbons from the tubing into the subsea tree to surface lines with the ability to stop the flow by closing the flow valve and/or the master valve; b) provide monitoring and pressure adjustment of the annulus; c) provide vertical tool access through the swab valve(s) for vertical trees or through crown plug(s) for horizontal trees.	
C. Design, construction and selection	1. The subsea tree shall be equipped with: a) one fail-safe closed automatic master valve and one fail-safe closed automatic wing valve in the main flow direction of the well; b) if the tree has side outlets, these shall be equipped with fail-safe closed automatic valves; c) one swab valve and tree cap (vertical tree) or two crown plugs (horizontal tree) for each bore at a level above any side outlets; d) isolation valves on downhole control lines which penetrates the tree block; and 2. The tree shall be designed to withstand dynamic and static loads it may be subjected to including normal, extreme and accidental load conditions.	ISO 10423 ISO 13628-1 ISO 13628-4 ISO 13628-7
D. Initial test and verification	The valves shall be tested with both low and high maximum differential pressure in the direction of flow. The low pressure test shall be maximum 35 bar (500 psi). The connection between the subsea tree and the wellhead shall be tested to maximum differential pressure.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The automatic valves shall be tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; thereafter c) every six months. 2. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 3. Test duration shall be minimum 10 min. 4. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valves close on signal.	
G. Common well barrier	None	

15.32 Table 32 – Subsea test tree assembly

Features	Acceptance criteria	See
A. Description	This element consists of: A fluted hanger, slick joint, housing with two fail-safe close valves, a disconnectable part consisting of a housing with a latching mechanism, control lines and chemical injection line(s) with check valves.	
B. Function	Its function is to seal the well from below, and allow the test string to be disconnected below the BOP shear seal ram, allowing this to be closed, before a possible riser disconnect.	
C. Design, construction and selection	1. It shall be equipped with a surface remote opening, fail-safe closing and unlatch/relatch function. For contingency purposes a mechanical unlatch feature shall also be available. 2. It shall be landed in the well head, allowing two of the pipe rams to seal around a slick joint isolating the test string annulus. 3. It shall be sufficiently short to allow the BOP shear seal ram to be closed above the tree valve assembly while valve and latch mechanism is connected. 4. A shearable joint shall be installed above the tree to facilitate emergency cutting of the string. 5. It shall be capable of cutting wireline or coiled tubing (including wire or capillary line inside) which may be utilised during well operations. It shall seal off the wellbore after cutting.	NORSOK D-SR-007
D. Initial test and verification	1. The SSTT spacing in the BOP stack shall be verified with a dummy run unless already proven. 2. The hydraulic primary latch mechanism shall be function tested (unlatch/latch) on rig floor after it has been made up to the test string. 3. It shall be pressure tested prior to setting the packer.	
E. Use	The SSTT valve shall not be used as an operational valve, only as a contingency device and in preparation or conjunction with disconnect of the test string.	
F. Monitoring	1. Ascertain pressure integrity of umbilical control line and availability of control line fluid. 2. Monitor pressure in BOP between SSTT valve and BOP SSR, prior to re-entry of a disconnected test string/riser.	
G. Common well barrier	None	

15.33 Table 33 – Surface tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with swab-, master valves, kill/service valves and flow valves.	
B. Function	Its function is to: 1. provide a flow conduit for hydrocarbons from the tubing into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve; 2. provide vertical tool access through the swab valve; and 3. provide an access point where kill fluid can be pumped into the tubing.	
C. Design, construction and selection	1. The surface tree shall be equipped with the following: a) one fail-safe closed automatic master valve and one fail-safe closed automatic wing valve in the main flow direction of the well; b) if the tree has flowing side outlets, these shall be equipped with automatic fail-safe valves; c) one manual swab valve and tree cap for each bore at a level above any side outlets; d) isolation valves on downhole control lines which penetrates the tree block. 2. All primary seals (inclusive production annulus) shall be of metal-to-metal type. 3. All connections, exit blocks etc. that lie within a predefined envelope shall be fire-resistant. 4. The tree shall be designed to withstand dynamic and static loads it may be subjected to including normal, extreme and accidental load conditions.	ISO 10423 (API Spec 6A) API Spec 6FA API Spec 6FB API Spec 6FC
D. Initial test and verification	The valves shall be tested with both low and high maximum differential pressure in the direction of flow. The low pressure test shall be maximum 35 bar (500 psi). The connection between the surface tree and the wellhead shall be tested to maximum differential pressure.	
E. Use	1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing. 2. Beware of equalization during opening and closing of valves.	
F. Monitoring	1. The automatic valves shall be tested at regular intervals as follows: a) monthly, until three consecutive qualified tests have been performed; thereafter b) every three months, until three consecutive qualified tests have been performed; hereafter c) every six months. 2. The manual valves shall be tested yearly. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. Test duration shall be minimum 10 min. 5. The emergency shutdown function shall be tested yearly. It shall be verified acceptable shut down time and that the valve closes on signal.	
G. Common well barrier	None	

15.34 Table 34 – Surface test tree

Features	Acceptance criteria	See
A. Description	This element consists of a housing with bores that are fitted with swab, master, kill and flow valves. It can also contain a swivel with internal seals.	
B. Function	Its function is to: 1. provide a flow conduit for hydrocarbons from the test tubing or the work over riser with the ability to stop the flow by closing the flow valve and/or the master valve; 2. provide kill fluid access via the kill valve; 3. allow access for wireline or coiled tubing intervention; 4. if swivel is included; allow rotation of the test string below the swivel.	
C. Design, construction and selection	1. It shall be equipped with a remote operated flow wing and kill valve, flow wing valve shall be of fail-safe close type. 2. The flow valve shall be controlled by the PSD/ESD system 3. A non-return valve shall be connected to the kill inlet to prevent backflow of fluid. 4. If the tree is equipped with a swivel, this shall be placed above the master valve.	NORSOK D-SR-007
D. Initial test and verification	1. All components shall be pressure tested to maximum well pressure after it has been made up to test string. 2. The flow valve shall be function tested under expected flowing pressure (not maximum pressure) conditions. The closure response time shall be verified to be within 5 seconds.	
E. Use	1. For floating rigs the STT when landed in the subsea wellhead shall have clear travel over the entire compensating stroke at both high and low tide. 2. For floating rigs maximum heave limitation shall be documented.	
F. Monitoring	1. Ascertain pressure integrity of hydraulic control lines and availability of control line fluid. 2. If the tree is equipped with a swivel this shall be made subject to regular visual inspection for sign of leaks or seizure during the operation.	
G. Common well barrier	None	

15.35 Table 35 – Well test packer

Features	Acceptance criteria	See
A. Description	This element consists of an annular seal element placed outside the tubing against the casing of the well.	
B. Function	Its purpose is to provide a principal seal, separating communication between the formation and the annular space around the tubing.	
C. Design, construction and selection	1. The packer shall hold pressure from above and below. 2. The seal shall withstand the maximum differential pressure across the packer, which shall be calculated based on (whichever gives the highest) of the following: a) applied pressure to the annulus less minimum reservoir pressure; b) maximum reservoir pressure less hydrostatic pressure of fluid in annulus; c) leaking tubing, equal to wellhead shut-in pressure plus, hydrostatic pressure of fluid in annulus less reservoir pressure; d) evacuated tubing with downhole tester valve “open” pressure on annulus. 3. The well test packer shall be tested as per ISO 14310, and the class it has been tested to shall be quoted. The test should be conducted in unsupported, non-cemented, standard casing. 4. HPHT wells: Fully anchored (permanent) packers shall be used. 5. Underbalanced annulus well testing; where retrievable packers are used, it shall be verified that packer cannot be unset due to upward forces generated.	NORSOK D-SR-007
D. Initial test and verification	1. The packer shall be pressure tested to maximum differential pressure. 2. The packer shall be pressure tested from below where a differential from below may be encountered during the well test.	
E. Use	Running of intervention tools shall not impair the packer’s ability to seal nor inadvertently cause the packer to be released.	
F. Monitoring	Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Common well barrier	None	

15.36 Table 36 – Well test string components

Features	Acceptance criteria	See
A. Description	These elements consist of a housing with a bore. The element may have a side mounted feature or a valve providing communication between tubing and annulus.	
B. Function	Its purpose may be to provide support to the functionality of the test string, e.g. slip joints, circulating valves, sampling tools, gauge carriers, safety joints, jars, etc.	
C. Design, construction and selection	1. The components (pipe and threads) shall be gas tight. 2. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 3. The component should be designed/selected with respect to: a) burst and collapse criteria; b) tensile and compression load exposure; c) jarring effects required to release a stuck test string; d) OD clearance and fishing restrictions; e) well flow rates, also including erosion effects; f) metallurgical composition in relation to exposure to formation, injection or annulus fluid; g) welding or odd shaped casting assemblies should be avoided; h) HPHT: Strength reduction due to temperatures effects to be applied.	NORSOK D-SR-007
D. Initial test and verification	Pressure testing to WDP.	
E. Use	Running of intervention tools shall not accidentally function a tool.	
F. Monitoring	Pressure integrity is monitored by ability to control the annulus pressure.	
G. Common well barrier	None	

15.37 Table 37 – Wireline rams

Features	Acceptance criteria	See
A. Description	This element consists of a BOP body with rams and riser/lubricator connections.	
B. Function	The function of the WL BOP is to prevent flow from the wellbore in case leakage in stuffing box / grease head or lubricator system above the BOP. The element is a back-up element to the stuffing box/grease head in the primary well barrier.	
C. Design, construction and selection	The wireline rams shall be constructed in accordance with NORSOK D-002.	NORSOK D-002
D. Initial test and verification	1. Function test after installation. 2. Perform low and high pressure leak tests after initial installation (may be omitted if within 14 days of previous on-site test). 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The WL cable rams shall be activated as described in the well control action procedures (contingency procedures should be established).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak-and functional test, minimum each 14 days when in operation.	
G. Common well barrier	None NOTE If the wireline safety head is incorporated in the same body – see table 38.	

15.38 Table 38 – Wireline safety head

Features	Acceptance criteria	See
A. Description	This element consists of a body with a shear/seal ram and riser connections.	
B. Function	Its function is to prevent flow from the wellbore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the wellbore with or without cable through the safety head. The element is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	The WL safety head shall be constructed in accordance with NORSOK D-002.	NORSOK D-002
D. Initial test and verification	1. Function test after installation. 2. Perform low and high pressure leak tests after initial installation (may be omitted if within 14 days of previous on-site test). 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	1. The WL safety head shall be activated as described in the well control action procedures (contingency procedures should be established by the user). 2. The safety head shall normally only be closed in an emergency and during leak-and function testing.	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak-and functional test, minimum every 14 days when in operation.	
G. Common well barrier	The wireline safety head (body, sealing rams and lower connection) will normally be defined as a common WBE. Consequence reducing measures can be: 1. Prepare a kill inlet (with double valve) for connection of a pumping line. It may also be considered to have a kill line hooked up to a kill pump with kill fluid available. 2. Confirm by simulation that the cable will fall below the tree valves in the event of being cut (allowing the tree valves to be closed). 3. Ensure that the BHA can be raised and/or lowered in emergency situations (e.g. in the event of a local emergency shutdown).	

15.39 Table 39 – Wireline stuffing box / grease injection head

Features	Acceptance criteria	See
A. Description	This element consists of a pressure control head and a lubricator connection.	
B. Function	The function is to provide the primary pressure seal between the wellbore and the atmosphere while allowing the WL to move into or out of the well. This is the upper closure device in the primary well barrier.	
C. Design, construction and selection	The WL stuffing box / grease head shall be constructed in accordance with NORSOK D-002.	NORSOK D-002
D. Initial test and verification	1. Function test after installation. 2. Perform low and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The activation/grease injection pressure shall be sufficiently high to maintain a dynamic pressure seal, and simultaneously as low as possible to avoid excessive friction when moving the cable.	
F. Monitoring	Visual periodic inspection	
G. Common well barrier	None	

15.40 Table 40 – Stab-in safety valve

Features	Acceptance criteria	See
A. Description	This element consists of a housing with a bore and a ball valve.	
B. Function	Its purpose is to allow mounting and closure at the top of any free tubular joint sitting in the rotary table.	
C. Design, construction and selection	1. The valve shall be rated to WDP. 2. The valve shall have an easily accessible and operable closure mechanism for use once the valve is installed on the string.	
D. Initial test and verification	The valve shall have a documented and accepted test performed within the last 14 days.	
E. Use	1. The stab-in safety valve shall be made up with threaded connections to match the tubing joint sitting in the rotary table at any time. 2. The valve shall be possible to make up hand-tight in less than 15 seconds.	
F. Monitoring	Visual observation during use	
G. Common well barrier	None	

15.41 Table 41 – Casing float valves

Features	Acceptance criteria	See
A. Description	The element consists of a tubular body and an internal one-way valve.	
B. Function	The purpose is to prevent flow of fluids from the wellbore up the casing/liner during installation of casing/liner and to allow for circulating the well.	
C. Design construction selection	1. The element shall allow for pumping fluids down the casing/liner but prevent any flow in the opposite direction. 2. The element shall withstand expected burst, collapse and axial loads including design factors. 3. The working/sealing pressure of the element shall be equal to the maximum differential pressure across the element plus a defined safety factor. 4. The element shall function at expected wellbore conditions with regards to differential pressure, temperature and fluid characteristics. 5. There shall be a minimum of two casing float valves. A convertible casing float (autofill) can be used when there are no sources of inflow exposed.	ISO 10427-3
D. Initial test and verification	1. Specifications and performance shall be documented by vendor. 2. Should be inflow/function tested during casing/liner running.	
E. Use	Shall be installed according to vendor’s procedure.	
F. Monitoring	Not applicable after initial testing	
G. Common well barrier	None	

15.42 Table 42 – Lower riser package for well intervention

Features	Acceptance criteria	See
A. Description	This element consists of a valve body with a shear/seal ram and a riser connector.	
B. Function	The function of the LRP is to prevent flow from the wellbore in case of loss or leakage in the primary well barrier at the surface. It shall be able to close in and seal the wellbore with or without CT or wireline through the LRP. The LRP is the upper closure device in the secondary well barrier.	
C. Design, construction and selection	1. The LRP shall be designed in accordance with ISO 13628-7. 2. The pressure rating shall exceed the maximum differential pressure that it can be exposed to, including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the CT or wireline and seal the wellbore thereafter. If this cannot be documented by the manufacturer, a qualification test shall be performed and documented.	ISO 13628-7 NORSOK D-002 ISO 13533 ISO 15156-1 API RP 5C7
D. Initial test and verification	1. Function test after initial installation. 2. Leak test after initial installation. 3. Leak test connections where seals have been de-energized to maximum WHP on following runs.	
E. Use	The LRP shall be activated as described in the well control action procedures (contingency procedures need to be established by the user).	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak and functional test, minimum every 14 days.	
G. Common well barrier	None	

15.43 Table 43 – Liner top packer / tie-back packer

Features	Acceptance criteria	See
A. Description	This element consists of a body with an annular sealing element which is activated during installation.	
B. Function	Its purpose is to seal the annulus between the casing and liner, and resist pressures from below and/or above.	
C. Design, construction and selection (rating, capacity, etc.)	1. The packer, including a tie-back packer, shall be qualified and tested in accordance to principles given in recognized standards, i.e. ISO14310 V1 as minimum, and V0 if the well contains free gas at the setting depth. The packer shall be qualification tested in relevant, unsupported, non-cemented casing. 2. The packer shall be designed for the maximum differential pressure (burst and collapse) and maximum downhole temperature expected during installation and throughout its service life. Other downhole conditions, such as formation fluids, H_2S, CO_2, etc. shall also be considered in estimating the lifetime of the packer. 3. The packer element is not accepted as a WBE in permanently abandoned wells or wellbores. 4. The risk of sealing failure due to variable downhole temperatures/cyclic loading shall be evaluated. 5. It shall be designed to avoid prematurely setting and allow rotation before set.	ISO 14310 ISO/FDIS 14998
D. Initial verification	It shall be pressure tested from above. For development wells, it should be inflow tested, if practicably possible. The pressure shall a) be 70 bar (~1000 psi) above measured leak off at the casing shoe/or potential leak path below, b) not exceed casing pressure test, whichever is lower.	
E. Use	None	
F. Monitoring	When liner top packer is installed above the production packer, its sealing performance shall be monitored through continuous recording of the A-annulus pressure measured at wellhead level.	
G. Common well barrier	None	

15.44 Table 44 – Wireline lubricator

Features	Acceptance criteria	See
A. Description	This element consists of a body with a lubricator connection in both ends.	
B. Function	The function is to provide lubricate space for BHA over the closing device when run into and out of well.	
C. Design, construction and selection	The WL lubricator shall be constructed in accordance with NORSOK D-002.	NORSOK D-002
D. Initial test and verification	1. Function test after installation. 2. Perform low and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The total length of lubricators shall allow sufficient height, above the upper well closing device, to contain the complete toolstring including items pulled from the well.	
F. Monitoring	Visual periodic inspection	
G. Common well barrier	None	

15.45 Table 45 – Subsea lubricator valve

Features	Acceptance criteria	See
A. Description	This element consists of a housing with a bore and a hydraulically operated valve.	
B. Function	Its purpose is to seal off the bore in the landing string to allow lubrication of long wireline or CT tools without having to close the SSTT and depressurize the entire landing string.	
C. Design, construction and selection	1. The valve shall hold pressure in both directions. 2. It shall be possible to pump through the valve 3. The valve shall fail as is. 4. Pressure lock between multiple valves shall not be possible. 5. Chemical injection shall be included (typically for hydrate prevention purposes).	NORSOK D-SR-07
D. Initial test and verification	It shall be pressure tested to maximum well pressure from both directions.	
E. Use	It is recommended to run two lubricator valves (back-up in the hole).	
F. Monitoring	Regular inflow or pressure testing in conjunction with every time use.	
G. Common well barrier	None	

15.46 Table 46 – Downhole tester valve

Features	Acceptance criteria	See
A. Description	This element consists of housing and a valve, located closely above the test packer.	
B. Function	Its function is to provide a seal in the test tubing bore for: a) downhole shut-in for pressure build-up; b) circulating the well to kill fluid in conjunction with a circulating device; c) running the test string with different densities of the fluids in the test string and the wellbore.	
C. Design, construction and selection	1. Shall be operated by annulus pressure. 2. Shall hold pressure from above and below. 3. Shall have a lock open position where applied annulus pressure is not required to keep the valve open.	NORSOK D-SR-007
D. Initial test and verification	The valve should be leak tested in the direction of flow and function tested on deck prior to installation.	
E. Use	None	
F. Monitoring	Pressure integrity of the closed valve should be established by monitoring the tubing pressure.	
G. Common well barrier	None	

15.47 Table 47 – Snubbing stripper BOP

Features	Acceptance criteria	See
A. Description	The element consists of two each BOP rams with equalizer and bleed off line valves. The stripper BOP normally consists of one lower stripper ram and one upper stripper ram.	NORSOK D-002
B. Function	The stripping rams are utilized to allow for controlled movement of upset and non-upset tubular in wells with surface pressure. By means of alternating between opening and closing the two stripping rams, tool joints can be stripped in/out the well while retaining full control of tubing annulus, i.e. the stripping rams are the highest primary WBEs when snubbing "ram-to-ram". The stripping rams are defined as back-up WBEs if the stripper rubber is used when RIH or pulling out of hole.	
C. Design, construction and selection	1. It shall be constructed in accordance with NORSOK D-002. 2. Its WP shall exceed the WDP including a margin for killing operations. 3. The stripper ram shall be able to provide a seal on the snubbing annulus. 4. The stripper rams shall be equipped with ram blocks designed for stripping. 5. The lower stripper ram shall be able to provide a seal from above. 6. The upper stripper ram shall be able to provide a seal from below.	NORSOK D-002 ISO 13533 ISO 15156-1
D. Initial test and verification	1. Function test after initial installation. 2. Perform low and high pressure leak tests after initial installation. 3. Leak test connections where seals have been de-energised to maximum WHP on following runs.	
E. Use	The stripper BOPs shall be activated as described in the well control action procedures (contingency procedures).	
F. Monitoring	Periodic visual inspection for external leaks Periodic leak- and functional test, minimum every 14 days	
G. Common well barrier	None	

15.48 Table 48 – Rotating control device

Features	Acceptance criteria	See
A. Description	The RCD is a drill through device designed with the purpose of allowing rotation of the drill string and containment of pressure or fluid to surface by the use of seals or packers that contact and seal against the drill string (drill pipe, casing etc.).	
B. Function	Its function is to contain fluids in the wellbore and divert flow from the wellbore to the surface fluids handling equipment during underbalanced operations (drilling, tripping and running completion equipment).	
C. Design, construction and selection	1. The RCD shall operate as designed within the expected operating pressure range including a predefined safety factor. Pressure ratings of RCD systems shall be defined by API 16 RCD testing. 2. The RCD shall have a dynamic pressure rating greater than or equal to the maximum expected wellhead pressure while rotating the work string, and a static pressure rating greater than or equal to the maximum expected wellhead pressure against a stationary work string. 3. Design should be such that change out of the primary seal elements is possible with the work string in the well. 4. The sealing elements of the RCD shall be compatible with the operating fluid environment expected (drilling fluid). For UBD operations the sealing elements shall be compatible with gas and multiphase fluid. API Spec 16RCD test results should be available with comparable drilling fluid to that being used. 5. The sealing elements shall be compatible with the expected operating temperature range. 6. The RCD shall be capable of withstanding vibration and shock loads without failure of the sealing mechanisms. 7. All metallic materials, which come in contact with well fluids with potential for H_2S, shall meet the requirements of ISO 15156-1 for sour service. 8. The RCD can wear out over time or fail suddenly. An evaluation of frequency and consequence of a sudden failure should be performed.	API Spec 16RCD ISO 13533 NORSOK Z-015 Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240 ISO 15156-1
D. Initial test and verification	1. The RCD shall (prior to delivery) pass a documented pressure test to 35 bar (500 psi) for 5 min and to the static pressure rating for 10 min. 2. Material certificates shall be available. 3. Upon initial installation on location, the RCD shall be leak tested to 35 bar (500 psi) for 5 min and to maximum MPD/UBD system RWP for 10 min. 4. After initial installation, pressure integrity of replacement sealing elements shall be verified by testing with the maximum available well pressure at surface.	
E. Use	The following should be implemented during operation to reduce wear on RCD: 1. limit level of vibration of drill string; 2. align drill string, derrick, and BOP stack; 3. ensure optimal drill string body and tool joint surface (smoothen tong marks, hardbanding, and API grooves/slots); 4. test fluid compatibility with RCD element; 5. record tool joint passages through element and minimize them when practical.	
F. Monitoring	1. Pressure monitoring across elements and monitoring static fluid level on trip tank (filled annulus above element) in addition to visual checks for continuous leaks past seal elements during operation. 2. Periodic leak and functional test, at same frequency as drilling BOP, when in operation.	
G. Common well barrier	None	

15.49 Table 49 – Downhole isolation valve

Features	Acceptance criteria	See
A. Description	The DIV is a full-opening drill through valve, installed down-hole as an integral part of a casing/liner string, at a depth either below the maximum pipe light depth for the work string being tripped in the underbalanced operation (drill string, casing, completion string, etc.) or at a depth that allows the maximum length of BHA, slotted liner or sand screen required to be safely deployed, without having to snub in or kill the well prior to deployment.	
B. Function	The DIV functions as the primary down-hole well barrier, isolating the open hole section with reservoir from the fluid system above the DIV.	
C. Design, construction and selection	1. The selected DIV shall meet the burst and collapse design criteria for the casing/liner string of which it is an integral component. 2. The DIV shall be capable of withstanding vibration, shock loads, rotating tool joints and exposure to a high solids environment without failure of the sealing mechanisms. 3. RWP shall exceed the maximum differential pressure after closure. 4. The sealing elements shall be compatible with the operating fluid environment (liquid, gas and multiphase) expected and the expected operating temperature envelope. 5. All metallic materials, which come in contact with well fluids with potential for H_2S, shall meet the requirements of ISO 15156-1 for sour service. 6. The DIV shall positively indicate to the operator at surface, the relative position of the shutoff mechanism (open/close). 7. A fluid column should be maintained above the valve.	ISO 28781 Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240
D. Initial test and verification	1. The DIV shall (prior to delivery) pass a documented differential pressure test to 35 bar (500 psi) for 5 min and to the WP rating for 10 min with a gas medium and shall not leak. Testing shall be in the direction of flow. 2. Material certificates for the DIV and components shall be available. 3. After initial installation on location, the DIV shall be leak tested to 35 bar (500 psi) for 5 min and to the WP rating of the DIV for 10 min. Testing shall be in the direction of flow. 4. After initial installation, pressure integrity of the DIV shall be verified by inflow testing prior to tripping out with the work string, with the BHA above the DIV.	
E. Use	The DIV is connected to the last casing or tubing run prior to drilling underbalanced in the reservoir section to be isolated with the DIV.	
F. Monitoring	The fluid column above the DIV shall be monitored continuously.	
G. Common well barrier	None	

15.50 Table 50 – UBD/MPD non-return valve

Features	Acceptance criteria	See
A. Description	The NRV is an insert type non-ported valve installed in a float sub that is run as an integral part of the work string to be used in a managed pressure or underbalanced operation. The typical valve can be a dart/plunger type or a flapper type. A minimum of two NRV valves constitute one WBE.	
B. Function	The NRV provides shut off against high or low pressure and prevents fluid flow to surface from below the valve.	
C. Design, construction and selection	1. The NRV float sub shall at a minimum meet the burst, collapse and torsion design criteria for the work string of which it is an integral component. 2. The ability to positively lock the NRV in place shall be inherent in the design of the float sub. 3. The NRV shall be capable of withstanding vibration, shock loads, and exposure to a solids environment without failure of the sealing mechanisms. 4. RWP shall exceed the maximum differential pressure the NRV will be exposed to in MPD/UBD mode including a predefined safety factor. 5. The sealing elements shall be compatible with the operating fluid environment (liquid, gas and multiphase) expected and the expected operating temperature range. 6. The NRV should be in accordance with NORSOK D-002 except for the normative references to other Norwegian/NORSOK standards. 7. The NRV’s shall be installed as deep and as close together in the string as possible. Installation of additional NRV's shall be considered depending on the nature of the operation (i.e. high-pressure gas).	NORSOK D-002 Specific to elastomer testing ASTM D412 ASTM D471 ASTM G111 ASTM D2240
D. Initial test and verification	1. The NRV shall (prior to delivery) pass a documented differential pressure test to 35 bar (500 psi) for 5 min and to the WP rating for 10 min and shall not leak. For UBD the test shall be performed with a gas medium. For MPD, testing with water is acceptable. 2. Material certificates shall be available. 3. After initial installation, pressure integrity of the NRV shall be verified by inflow testing during connections. 4. After redressing an NRV on location, the NRV assembly shall be leak tested using water to the maximum differential pressure the NRV will be exposed to including a predefined safety factor. Only manufacturer’s original equipment with the same specifications will be acceptable for redressing. Testing shall be in the direction of flow.	
E. Use	1. The work string above the NRV should be fluid filled while RIH. Sudden quick starting and stopping of the circulation system pumps should be avoided. 2. Debris across the NRV will prevent proper closure and cause damage to the valve. The use of drill pipe screens is recommended.	
F. Monitoring	Inflow tests during connections	
G. Common well barrier	None	

15.51 Table 51 – In-situ formation

Features	Acceptance criteria	See
A. Description	The element is the formation that has been drilled through and is located adjacent to the casing annulus isolation material or plugs set in the wellbore.	
B. Function	The purpose of the in-situ formation is to provide a permanent and impermeable hydraulic seal preventing flow from the wellbore to surface/seabed or other formation zones.	
C. Design construction selection	The following applies for the formation at the required depth: 1. The formation shall be impermeable with no flow potential. 2. The wellbore shall be placed away from fractures and/or faults that may lead to out of zone injection or crossflow. 3. The formation integrity shall exceed the maximum wellbore pressure induced. See 4.2.3.6.7 Table 2 – Formation Integrity requirements. 4. The formation shall be selected such that it will not be affected by changes in reservoir pressure over time (depletion, compaction, fracturing, re-activation of faults). 5. The formation shall bond directly to the casing/liner annulus material (e.g. casing cement) or plugs in the wellbore. 6. If the formation is bonding directly to the casing (e.g. the formation has extruded into the casing annulus), then the requirements in table 15.52 Creeping formation also shall apply.	
D. Initial test and verification	Formation integrity pressure shall be verified by one of the following methods (See 4.2.3.6.7): 1. a PIT; 2. a LOT should be followed by a shut-in phase; 3. an XLOT, if the minimum formation stress is not already known; or 4. a documented field model.	
E. Use	None	
F. Monitoring	None	
G. Common well barrier	None	

15.52 Table 52 – Creeping formation

Features	Acceptance criteria	See
A. Description	The element consists of creeping formation (formation that plastically has been extruded into the wellbore) located in the annulus between the casing/liner and the bore hole wall.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along the casing annulus to prevent flow of formation fluids and to resist pressures from above and below.	
C. Design, construction and selection	1. The element shall be capable of providing an eternal hydraulic pressure seal. 2. The minimum cumulative formation interval shall be 50 m MD. 3. The minimum formation stress at the base of the element shall be sufficient to withstand the maximum pressure that could be applied. 4. The element shall be able to withstand maximum differential pressure.	
D. Initial test and verification	1. Position and length of the element shall be verified by bond logs: a) Two (2) independent logging measurements/tools shall be applied. Logging measurements shall provide azimuthal data. b) Logging data shall be interpreted and verified by qualified personnel and documented. c) The log response criteria shall be established prior to the logging operation. d) The minimum contact length shall be 50m MD with 360 degrees of qualified bonding. 2. The pressure integrity shall be verified by application of a pressure differential across the interval. 3. Formation integrity shall be verified by a LOT at the base of the interval. The results should be in accordance with the expected formation stress from the field model (see table 15.51 In-situ formation). 4. If the element has been qualified by logging, pressure and formation integrity testing, logging is considered sufficient for subsequent wells. The formation interval shall be laterally continuous. Pressure testing is required if the log response is not conclusive or there is uncertainty regarding geological similarity.	
E. Use	The element is primarily used in a permanently abandoned well.	
F. Monitoring	None	
G. Common well barrier	None	

15.53 Table 53 – UBD/MPD choke system

Features	Acceptance criteria	See
A. Description	The MPD/UBD choke manifold is a control device for the purpose of controlling the pressure and fluid flow to surface from the well. It consists of isolation valves, flow line from the well and a choke manifold.	
B. Function	Its function is to control the wellhead pressure within predefined limits and reduce return fluid pressure to atmospheric or separator inlet pressure.	
C. Design, construction and selection	1. The choke manifold shall be fit for purpose to operate within the expected operating pressure range. 2. The choke manifold shall have a RWP exceeding the maximum UBD/MPD operating pressure, including a predefined safety factor. 3. The elements of the choke components shall be compatible with the operating fluid environment (liquid, gas, drill cuttings and multiphase fluids) expected. The system shall be able to handle the rates of the returning fluids and solids. 4. The elements of the choke manifold shall be compatible with the expected operating temperature range. 5. The choke manifold shall be capable of withstanding vibration and shock loads without failing. 6. Choke size shall be selected to optimize wellhead pressure control and minimize wear. 7. All metallic materials, which come in contact with well fluids with potential for H_2S, shall meet the requirements of ISO 15156-1 for sour service. 8. It shall be possible to redress a choke valve with double block and bleed isolation from any pressure source. 9. The choke manifold shall have two separate flow paths including chokes and isolation valves for each choke and flow path. 10. A risk assessment (e.g. FMECA – Failure Mode, Effects, and Criticality Analysis or equivalent) shall be done on the choke manifold including control system. 11. The flowline from the well shall include two isolation valves where at least one shall be remote operated. 12. The MPD/UPD operator work station should be located at the drill floor together with the driller. <u>MPD specific requirements:</u> 13. A high accuracy flow meter shall be installed on the return line upstream or downstream of the choke. 14. A PRV (valve/choke) shall be fitted upstream of the choke to avoid exceeding the pressure rating of the MPD system. The PRV shall be able to operate independent of the MPD control system. 15. The choke shall be controlled by an automatic computer based system. 16. The remotely operated valve on the flowline shall be failsafe as is. <u>UBD specific requirements:</u> 17. The remotely operated valve on the flowline shall be fail-safe close (ESDV), and have a RWP exceeding the SIWHP. The ESDV shall be proven to prevent over-pressuring/flowing of the separation equipment in event of a downstream blockage.	ISO 15156-1 NORSOK Z-015

Features	Acceptance criteria	See
D. Initial test and verification	1. The choke manifold elements, including flowline and valves, shall be leak tested to 35 bar (500 psi) for 5 min and to maximum MPD/UBD system working pressure for 10 min prior to delivery, after initial installation and after repair or replacement. NOTE The choke valves are not designed to hold static pressure and therefore only require body testing. 2. When using an automatic choke control system in MPD acceptance testing shall be performed to verify capability of system to achieve required bottom hole pressure range. 3. Integrated function testing shall be carried out after initial installation and shall include the choke control system(s). 4. Material certificates shall be available.	
E. Use	1. Choke swapping in the event of a blockage shall be automated or controlled through procedure. 2. The hydraulic model shall be calibrated during drilling to match the real time downhole pressure data.	
F. Monitoring	1. Corrosion and erosion programs shall be developed to reflect the operating conditions. Regular MPI tests should be part of the program. 2. Periodic visual inspection for external leaks. 3. Upstream choke pressures shall be monitored and controlled by independent and redundant pressure monitoring systems. 4. Indication of choke position shall be monitored. 5. Periodic leak and functional test, minimum every 14th day.	
G. Common well barrier	None	

15.54 Table 54 – Statically underbalanced fluid column

Features	Acceptance criteria	See
A. Description	This is the fluid in the wellbore during MPD/UBD operations.	NORSOK D-001
B. Function	The purpose of the statically underbalanced fluid column is to exert hydrostatic pressure on the wellbore. Unlike the fluid column in Table 1, this is a statically underbalanced element that requires the use of additional WBEs (for example, an RCD and choke manifold) to establish a primary barrier.	
C. Design construction selection	MPD specific requirements: 1. The fluid density should: a) be maximized; b) give sufficient choke operating range; c) be lower than the minimum formation stress in the open hole section (to ensure a backpressure can be sustained even in a lost circulation incident). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under downhole conditions for a specified period of time when no circulation is performed. 4. Changes in wellbore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and integrated into the MPD operating parameters. UBD specific requirements: 5. Explosive limits shall be established for all circulating media systems, which have the potential to introduce oxygen into the circulating stream. 6. Hydrate curves shall be generated and fluid selection and design shall include measures to prevent hydrate formation. 7. A multiphase flow simulation should be performed to evaluate hole cleaning efficiency. 8. In applications where there is a significant risk of developing foaming or emulsion problems, lab testing shall be conducted to optimize preventive measures. 9. The compatibility of the circulating media, both injected and produced, with other components of the circulating system, shall be reviewed to address the potential for formation damage, corrosion and degradation of the circulating system components, both at surface and downhole.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified through the use of MPD equipment. 2. Critical fluid properties, including density shall be within specifications.	
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. If there is a risk of lost circulation, lost circulation material should be available. 4. Enough kill fluid of sufficient density shall be available on site at any time to be able to kill the well in an emergency. In addition there should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density. 5. Simultaneous well displacement and transfer to or from the fluid tanks should only be done with a high degree of caution, not affecting the active fluid system 6. Parameters required for re-establishing the fluid well barrier shall be systematically recorded and updated in a “killsheet”.	

Features	Acceptance criteria	See
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. In MPD dynamic flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content or at specified regular intervals. The flow check should last for 10 min. HPHT: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well.	ISO 10414-1 ISO 10414-2
G. Common well barrier	None	

15.55 Table 55 – Material plug

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of material in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>
1. A program shall be issued for each material placement operation.
2. For critical material operations, HPHT conditions and complex material designs the material program should be verified independent (internal or external), qualified personnel.
3. Properties of each batch of material produced shall be verified by laboratory testing to ensure sealing capability. This shall be documented in the batch certificate issued by the manufacturing plant.
4. The annular barrier material recipe shall be lab tested with samples from the rigsite under representative well conditions
5. Materials used for plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (e.g. CO_2, H_2S).
6. Permanent material plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
7. It shall be designed for the highest differential pressure and highest downhole temperature expected, including installation and test loads.
8. The minimum material plug length shall be:
<table>
<tr><td>Open hole material plugs</td><td>Cased hole material plugs</td><td>Open hole to surface plug</td></tr>
<tr><td>100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing should extend at least 50 m MD above and below casing shoe.</td><td>50 m MD if set on a mechanical plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
</td><td>UK Oil and Gas
OP071</td></tr>
</table>

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial test and verification</td><td>
1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The plug installation shall be verified through evaluation of job execution taking into account hole enlargement, volumes pumped and returns.
3. Its position shall be verified by:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging</td></tr>
<tr><td>Cased hole</td><td>Tagging
Pressure test, which shall:
a) be 70 bar (1000 psi) above the estimated LOT below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and
b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
If the material plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.</td></tr>
</table>
</td><td></td></tr>
<tr><td>E. Use</td><td>None</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly, or inspected for leaks, when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>None</td><td></td></tr>
</table>

15.56 Table 56 – Casing bonding material

Features	Acceptance criteria	See
A. Description	This element consists of impermeable material in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (pumping program) shall be issued for each pumping job which covers the following: a) casing/liner centralization and stand-off to achieve pressure and sealing integrity over the entire required isolation length; b) use of fluid spacers; c) effects of hydrostatic pressure differentials inside and outside casing and ECD during pumping and loss of hydrostatic pressure prior to material placement; d) the risk of loss returns and mitigating measures during material placement. 2. For critical annular barrier operations, HPHT conditions and complex slurry designs the program should be verified by (internal or external), qualified personnel. 3. Properties of each batch of material produced shall be verified by laboratory testing to ensure sealing capability. This shall be docu-mented in the batch certificate issued by the manufacturing plant. 4. The annular barrier material recipe shall be lab tested with samples from the rigsite under representative well conditions 5. The properties of the set material shall provide lasting zonal isolation, structural support, and withstand expected temperature exposure. 6. Materials used for isolating sources of inflow containing hydrocarbons shall be designed to prevent gas migration, including CO_2 and H_2S if present. 7. Planned material length: a) Shall be designed to allow for future use of the well (sidetracks, recompletions, and abandonment). b) **General**: Shall be minimum 100 m MD above a casing shoe/window. c) **Conductor**: Should be defined based on structural integrity requirements. d) **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOM shall be inside the conductor shoe or to surface/seabed if no conductor is installed. e) **Production casing/production liner**: Shall be minimum 200 m above a casing shoe. If the casing/liner penetrates a source of inflow, the planned material length shall be 200m MD above the source of inflow. NOTE If unable to fulfil the requirement when running a production liner, the liner material length can be combined with previous casing material to fulfil the 200m MD requirement.	UK Oil and Gas OP071

Features	Acceptance criteria	See
D. Initial test and verification	The material should be left undisturbed until it has met sufficient compressive strength. 1. The material sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out. 2. The material length shall be verified by one of the following: a) Bonding logs: Logging methods/tools shall be selected based on ability to provide data for verification of bonding. The measurements shall provide azimuthal/segmented data. The logs shall be verified by qualified personnel and documented. b) 100 % displacement efficiency based on record from the pumping operation (volumes pumped, returns during pumping, etc.). Actual displacement pressure/volumes should be compared with simulations using industry recognized software. In case of losses, the loss zone shall be above the planned TOM, this shall be documented. Acceptable documentation is job record comparison with similar loss case(s) on a reference well(s) that has achieved sufficient length verified by logging. c) In the event of losses, it is acceptable to use the PIT/FIT or LOT as the verification method, only if the casing material shall be used as a WBE for drilling the next hole section. (This method shall not be used for verification of casing material as a WBE for production or abandoned wells). 3. Critical casing material shall be logged and is defined by the following scenarios: a) the production casing / liner when set into/through a source of inflow with hydrocarbons; b) the production casing / liner when the same casing material is a part of the primary and secondary well barriers; c) wells with injection pressure which exceeds the formation integrity at the cap rock. 5. Actual material length for a qualified WBE shall be: a) above a potential source of inflow/ reservoir; b) 50m MD verified by displacement calculations. The formation integrity shall exceed the maximum expected pressure at the base of the interval.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the casing material shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	
G. Common well barrier	None	

15.57 Table 57 – Riserless light well intervention – well control package

Features	Acceptance criteria	See
A. Description	This element consists of: 1. connector/adapter to fit the tree; 2. BOP body with two test valves and a safety head; 3. connection against the LLS.	
B. Function	The purpose of the element is to prevent flow from the wellbore to the environment in case of leakage in the primary well barrier (grease injection head).	
C. Design, construction and selection	1. The WCP shall be constructed in accordance with ISO 13628. 2. The pressure rating shall exceed maximum pressure it can be subjected to, including kill margin. 3. The WCP shall include a kill inlet below the safety head. 4. It shall be possible to connect and disconnect the kill hose by means of ROV. 5. The safety head shall be included in the ESD/EQD logic.	ISO 13628
D. Initial test and verification	1. Function test after installation. 2. Low and high pressure leak tests after installation	
E. Use	1. The safety head shall normally only be closed in an emergency or during leak. 2. The test valves are used as WBEs against the well during deployment in and out of the well.	
F. Monitoring	1. Periodic visual inspection for external leaks. 2. Periodic leak and functional test, minimum each 7th day when in operation.	
G. Common WBEs	The WCP (body, rams and vertical connections) will normally be defined as a common WBE. Consequence reducing measures can be: a) to have a kill inlet prepared (with double valve) for connection of a pumping line. It may also be considered to have a kill line hooked up to a kill pump with kill fluid available; b) to ensure that the BHA can be raised/lowered or cut in emergency situations.	

15.58 Table 58 – Riserless light well intervention – lower lubricator section

Features	Acceptance criteria	See
A. Description	This element consists of: 1. connection against the WCP; 2. lubricator tube; 3. wireline shear seal valve; 4. dual pack-off assembly (if not integrated in ULS); 5. connection against the ULS.	
B. Function	1. The function of the lubricator tube is to provide deployment length for the toolstring 2. The function of the WL shear seal valve is to cut wireline and provide a seal in case of a well control situation.	
C. Design, construction and selection	1. The lubricator shall be constructed in accordance with ISO 13628. 2. The pressure rating shall exceed maximum pressure it can be subjected to, including kill margin.	ISO 13628
D. Initial test and verification	1. Function test after installation. 2. Low and high pressure leak tests after installation.	
E. Use	The total length of lubricators shall allow sufficient height above the upper closing device to contain the complete toolstring including items pulled from the well.	
F. Monitoring	Periodic visual inspection for external leaks	
G. Common WBEs	None	

15.59 Table 59 – Riserless light well intervention – upper lubricator section

Features	Acceptance criteria	See
A. Description	This element consists of: 1. flowtubes / stuffing box; 2. dual pack-off assembly; 3. toolcatcher; 4. connector towards LLS.	
B. Function	1. The function of the flowtubes/stuffing box is to act as the primary barrier element while allowing the cable to move in or out of the well. 2. The function of the dual pack-off assembly is to provide a static seal in case the flowtubes fail to contain the wellbore pressure.	
C. Design, construction and selection	1. The ULS shall be constructed in accordance with ISO 13628. 2. The pressure rating shall exceed maximum pressure it can be subjected to, including kill margin. 3. The ULS shall include a check valve to prevent leaks in case of wireline breakage. 4. The dual pack-off assembly can be integrated in LLS.	ISO 13628
D. Initial test and verification	1. Function test after installation. 2. Low and high pressure leak tests after installation	
E. Use	The grease injection pressure shall be sufficiently high to maintain a dynamic pressure seal, and simultaneously as low as possible to avoid excessive friction when moving the cable.	
F. Monitoring	Periodic visual inspection for external leaks	
G. Common WBEs	None	

Annex A - Test pressures and frequency for well control equipment

The tables in this section are requirements (shall).

Table 38 – Routine pressure / leak testing of drilling BOP and well control equipment

	Frequency / Element	Stump	Before drilling out of casing		Before well testing	Periodic		
			Surface casing	Deeper casing and liners		Weekly	Each 14 days	Each 6 months
BOP	Annular preventers	WDP[1]	Function	SDP[1]	WDP[1]	Function	SDP[1]	WPx0,7
	Pipe rams	WDP[14]	Function	SDP	WDP	Function	SDP	WP
	Shear rams	WDP	Function	SDP	WDP	Function[15]		WP
	BOP choke and kill valves[3]	WDP	WDP[6]	SDP	WDP	Function	SDP	WP
	Well head connector	WDP	WDP[12]		WDP		SDP	WP
	Ram locking system	Function[10]						
	Casing shear ram	Function	Function	Function	Function			
BOP control system	Shear boost system	Function						
	Accumulator precharge pressure	Check						Check[8]
	Hydraulic chambers[5]	WP						
Secondary emergency systems	Emergency Acoustic system	Function	Function[11]	Function[11]		Communication	Close one ram	
	All ROV hot stab functions	WP						
	Emergency disconnect system	Function	Function[9]					
	Deadman (el. & hyd.power lost)	Function	Function[9]					
	Autoshear (when disconnecting)	Function	Function[9]					
Choke/kill line and manifold	Choke/kill lines	WDP	WDP	SDP	WDP		SDP	WP
	Manifold valves[3]	WDP		SDP	WDP		SDP	WP
	Chokes	Function		Function	Function	Function	Function	
Other equipment	Kill pump	WP[2]		SDP			SDP	WP
	Inside BOP	WDP[2]		SDP	WDP		SDP	WP
	Stabbing valves	WDP[2]		SDP	WDP		SDP	WP
	Upper kelly valve	WDP[2]		SDP			SDP	WP
	Lower kelly valve	WDP[2]		SDP			SDP	WP
	Standpipe manifold	WP[2]		WP[4]			WP[4]	
	Kelly hose	WP[2]		WP[4]			WP[4]	
	Diverter system		Function[13]					
	Riser slip joint	WP [7]						

Legend

WP working pressure
WDP well design pressure
SDP maximum section design pressure

Function Function test schedule shall be developed for testing alternate combinations of all panels and pods. As a minimum one pod from one panel shall be tested each week.

1 Or maximum 70 % of WP
2 Or at initial installation
3 Choke/kill valves (BOP and manifold) of bidirectional type to be tested in the direction they can be exposed to pressure in a well control situation. Valve can be tested from above if it is not practicable to test due to restriction of BOP arrangement.
4 WP of pump liners
5 To include hoses, control pods etc.
6 Test to WDP downstream
7 Riser slip joint packers to be pressure tested to WP before installation.
8 Subsea accumulators on stump. Surface BOP accumulators on minimum 6 months interval. Surface shear boost accumulators on stump.
9 This test shall be performed with BOP installed on wellhead and is only required during commissioning or within 5 year of previous test.
10 Ram locking system to be tested with ram close system vented during ram pressure testing
11 Communication and function BSR
12 For subsea BOP include overpull test to 25 mT after landing, prior to pressure testing.
13 Diverter system to be fully function tested to verify the components intended operations
14 Variable bore rams should be tested with minimum and maximum planned pipe OD
15 If no toolstring through BOP

- All low pressure tests shall be 15 to 20 bar and have a minimum test evaluation period of 5 min, while high pressure tests shall have a minimum test evaluation period of 10 min. Fluid volumes pumped/bled-back, time to open/close each function and deviations identified shall be recorded.
- If the entire drilling BOP stack is disconnected/re-connected or moved between wells without having been disconnected from its control system it is not required to repeat the pressure tests of the rams and annular preventers described under the heading “Before drilling out of casing.”
- At the time when the BOP is installed on a well, the time since the last BOP stump test should not exceed 14 days.

- The following shall be implemented after reconnect of the LMRP: a) Pressure test of K/C lines from above to WDP and LMRP connector to WDP or 70% of WP for annular, whichever is the lowest pressure. b) Function test both blue and yellow pod. c) Communication test of the emergency acoustic system.

Table 39 – Failure of drilling BOP and control systems

Barrier element/equipment	Actions to be taken when failure to test
Annular	Repair immediately** If two annulars are installed and only one annular fails to test consider repairing after having set casing, based on risk analysis.
Shear ram including ram locking device	If WBE, repair immediately**
Connectors/connections.	If WBE, repair immediately**
Pipe ram (upper, middle, lower) including ram locking device	If WBE, repair immediately** If two additional pipe rams are available to cover the requirements consider repairing rams that failed to test at a convenient time, based on risk analysis.
Choke valves, inner/outer Kill valves, inner/outer	If both valves in series have failed, repair immediately**. If one of two valves in series has failed consider repairing after having set casing, based on risk analysis.
Marine riser choke and kill line*	If one has failed, repair immediately**
Yellow and blue pod*	If both have failed, repair immediately**. If one has failed completely repair immediately. Subject to criticality of failed functions, consider repairing partly failed pod at a convenient time, based on risk analysis.
BOP control systems	Subject to criticality of failed functions, consider repairing at a convenient time, based on risk analysis.
Acoustic – shear ram*	Same as for shear ram
Acoustic – pipe rams*	Same as for pipe ram If ROV interface is available to activate pipe rams consider repairing the acoustic function after having set casing, based on risk analysis.

**Floating installations*

***Immediately: Stop operation and abandon well temporarily.*