Deepwater Well Design and Construction

API RECOMMENDED PRACTICE 96
Draft 4, March 22, 2011

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1 Foreword

Well integrity is the application of technical, operational, and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of the deepwater (DW) well. This document presents the well integrity information and recommended practices that engineers, well planners, and operators consider when planning and executing a DW well project.

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2 Introduction

The safe construction of a DW well requires proper well design and operational procedures. The complexity of DW operations (e.g., subsea blowout preventers [BOPs], metocean conditions, floating rigs) demands a thorough understanding of the DW well design criteria and associated equipment.

This recommended practice provides well design and operational considerations to assist an experienced well (drilling or completion) engineer to safely design and construct any DW well drilled with subsea BOPs. This document addresses drilling and completion activity performed with subsea BOPs, a marine drilling riser, and a subsea wellhead.

3 Scope

The complexity of DW operations requires a thorough understanding of its well design criteria and associated equipment. This recommended practice (RP) identifies considerations for use in DW well design, drilling, and completions operations for reference by drilling and completion engineers and operational personnel. Additionally, this RP will be useful during other project phases such as internal reviews, internal approvals, contractor engagements, and regulatory approvals.

The scope of this RP is to discuss DW drilling and completion activity performed on wells using subsea BOPs with a subsea wellhead. This document:

- Identifies the appropriate barrier and load case considerations to maintain well control during DW well operations (drilling, suspension, completion, and abandonment);
- Supplements barrier documentation in API RP 65 Part 2 with a more detailed description of barriers and discussion of the philosophy, number, type, testing, and management required to maintain well control. This document also supplements the barrier documentation in API RP 90 in regard to annular pressure buildup (APB). Abandonment barrier requirements are described for use when designing the well.
- Discusses load assumptions, resistance assumptions, and methodologies commonly used to achieve well designs with high reliability. The load case discussion includes less-than-obvious events that can arise when unexpected circumstances are combined.
- Describes the risk and mitigation practices commonly implemented during DW casing and equipment installation operations.

The purpose of this recommended practice is to provide DW design and installation practices that are believed to achieve a high level of total system reliability. These practices minimize the likelihood of loss of well control or damage to the environment and enhance the safety of those conducting the operation. While these practices are generally intended to apply to subsea wells drilled with subsea BOPs in any water depth, some of the descriptions of rig hardware and operations, such as remotely operated vehicles (ROVs), are less relevant in shallower water depths (e.g., less than 500 feet), and the operator may substitute alternative hardware or operations that maintain a high level of total system reliability in shallower water depths.

The following areas are outside the scope of this document:

- Detailed load case definitions (these are defined by each operator);
- Details for hybrid wells (spar, tension leg platform [TLP], or both) with surface BOP, pressured marine drilling riser or risers, and wellbay/well system interface (see API RP 2RD for more information about TLPs);
- Well control procedures (see API RP 59 for well control information);
- Dual gradient/drilling operations or managed pressure drilling operations;
- Production operations and fluids handling downstream of the tree (subsea facilities/subsea architecture and surface facilities/offloading hydrocarbons);
- Intervention operations;
- Quality assurance (QA) programs.

NOTE: This document does not include specific casing designs or design factors. Individual companies combine differing severities of loads and resistances or differing calculation methods to achieve designs with similar high levels of reliability.

4 References

4.1 Normative Reference

Normative references are considered indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata). A reference’s normative status (as opposed to informative-see 4.2) shall be made clear by the way in which it is referred to in the text, by an indication in the table of contents and under the heading of the reference.

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Informative references give additional information intended to assist the understanding or use of the document. They shall not contain requirements, except as described in the next paragraph. Their presence is optional. A reference’s informative status (as opposed to normative-see 4.1) shall be made clear by the way in which it is referred to in the text, by an indication in the table of contents and under the heading of the reference.

Informative references may contain optional requirements. For example, a test method that is optional may contain requirements but there is no need to comply with these requirements to claim compliance with the document.

5 Terms, Definitions, and Abbreviations

5.1 Terms and Definitions

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

5.1.1

"A" annulus

annulus between production tubing and production casing

5.1.2

autoshear circuit

blowout preventer control system circuit designed to automatically close blind shear ram(s) if the lower marine riser package disconnects

5.1.3

backup gradient

pressure gradient of fluid in the casing annulus (i.e., behind the casing)

5.1.4

basis of design

all factual information and assumptions utilized to design the well

5.1.5

barrier

component or practice that contributes to the total system reliability by preventing formation fluid or gas flow

5.1.6

barrier system

a combination of barriers acting in a series along a given potential failure path to prevent formation fluids or gases from unintentionally flowing from one side of the system to the other side along the particular path. The barrier system includes both physical barriers and operational practices.

5.1.7

barrier plan

the operator's standard operating procedure for barrier placement and removal

5.1.8

blind shear ram

rams which shear pipe and then seal, thus serving as the closing element on an open hole. The ends seal against each other and shut off the space below completely. Other common names for this ram include: shearing blind ram, blind shear, blind rams, blind/shear rams, etc.

5.1.9

blue pod

one of two subsea control system pods that sends hydraulic fluid to activate blowout preventer components (also see yellow pod)

5.1.10

can

indicates a statement is possible or that the statement is capable of an action

5.1.11

cement barrier

a subset of physical barriers, a cement column designed and placed to prevent formation fluid flow between zones or up the wellbore.

5.1.12

confirmed barrier

barrier whose proper deployment has been substantiated through a post-installation assessment or through observations recorded during its installation. A tested barrier has the greatest level of assurance.

5.1.13

consider

indicates a suggestion or advice to reader; it is not the equivalent of shall or should

5.1.14

deadman system

a safety system that is designed to automaticlaly close the blowout preventer blind shear rams and secure the well in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods

5.1.15

design factor

ratio of the capacity of a component to the load to which it is subjected

5.1.16

emergency disconnect sequence

upon human activation, provides automatic closure of the wellbore and automatic disconnect of lower marine riser packer when specific emergency conditions occur on a floating drilling vessel

5.1.17

fluid column barrier

see “hydrostatic barrier”

5.1.18

frac

a well treatment where a proppant is pumped into the well at high pressure to create a fracture (frac job)

5.1.19

horizontal tree

a Christmas tree design for subsea applications, which does not have a production master valve in the vertical bore but in the horizontal outlets to the side

5.1.20

hydrostatic barrier

hydrostatic pressure of fluid sufficient to prevent formation fluid influx

5.1.21

informative elements

describe the scope of the document, which set out provisions intended to assist in the understanding of the implementation of the standard

5.1.22

inflow test

a test in which the hydrostatic pressure is reduced such that the net differential pressure direction is into the wellbore. Inflow test is commonly known as a "negative test" or “negative differential test.”

5.1.23

kill-weight fluid

fluid that is of sufficient density such that hydrostatic pressure is greater than formation pressure

5.1.24

may

indicates that a provision, suggestion, advice, course of action, etc. is optional

5.1.25

mechanical barrier

subset of physical barriers that features mechanical equipment, such as a permanent bridge plug; does not include set cement or a hydrostatic fluid column

5.1.26

metocean

meteorological and oceanographic data such as wind, wave, water current, and tidal condition measurements

5.1.27

minimum design factor

the lowest acceptable design factor per company or regulatory requirements

5.1.28

negative test / negative differential test

See “inflow test”

5.1.29

open water

seawater between subsea wellhead and floating rig prior to installation of riser

5.1.30

operational barrier

system or process that acts to enhance the total system reliability (e.g., process to close BOPs or detect an influx). It is not a physical barrier.

5.1.31

piloted hydraulic

type of control system that uses individual hydraulic lines to actuate a subsea valve in the control pod that allows hydraulic actuation fluid to flow to function a BOP component

5.1.32

physical barrier

material object or set of objects intended to prevent the transmission of pressure and fluid flow from one side of the barrier to the other side. The barrier is designed to withstand the pressure of the potential flow source. It may be substantiated by testing to its full anticipated load or verified by alternative testing (Refer to Section 7.2.1 c). Includes mechanical barriers, cement barriers, and hydrostatic barriers. Does not include operational barriers.

5.1.33

riserless casing string

a string run in open water prior to the subsea stack being landed

5.1.34

safety factor

see “design factor”

5.1.35

shall

minimum requirement in order to conform to the relevant specification

5.1.36

should

recommendation or action that is advised, but not required, in order to conform to the relevant specification

5.1.37

stop work authority

a process that provides all operator and contractor/service personnel directly or indirectly involved with the operation the responsibility and authority to pause operations until the appropriate review of the activity can be concluded

5.1.38

subsea blow out preventer

blow-out preventer stack designed for use on subsea wellheads, tubing heads, or trees

5.1.39

subsea tree

the subsea tree controls the flow into or out of the well. The subsea tree may provide numerous additional functions including chemical injection points, well intervention means, pressure relief means (such as annulus vent), etc. It is placed on top the high pressure housing or tubing spool near the mudline.

5.1.40

tested barrier

a barrier whose performance has been assured through meeting the acceptance criteria of a pressure test performed in the direction of flow and to a pressure greater than the maximum pressure anticipated during the life of the barrier

5.1.41

total system reliability

the probability that the barriers acting in series along a given path will prevent uncontrolled flow of fluid or gas. Includes both physical barriers and operational barriers. Also known as “system reliability” and “well total system reliability.”

5.1.42

validate/validation

a quality assurance process of establishing evidence that provides a high degree of assurance that a product, service, or system accomplished its intended purpose. This often involves acceptance of fitness for purpose with end users and other product stakeholders

5.1.43

verified barrier

a barrier whose performance has been assured through meeting the acceptance criteria of a post-installation evaluation to a level less than that of a tested barrier or through evaluating data collected during installation

NOTE: in this document, the related term “validation” is used only with respect to the initial design of equipment (i.e., capacity calculations and any performance confirmation tests in a lab rather than in the well).

5.1.44

verify/verification

a quality control process used to evaluate whether or not a product, service, or system complies with regulations, specifications, or conditions imposed at the start of a development phase. Verification can be in development, scale-up, or production. This is often an internal process.

5.1.45

vertical tree

tree with the master valve in the vertical bore of the tree below the side outlet

5.1.46

watch circle

area of pre-determined size in which the drilling rig maintains its position in order to not exceed equipment or reaction time limitations

5.1.47

wellbay

area of a platform where the surface wellheads and trees are located

5.1.48

well control

activities implemented to prevent or mitigate an unintentional release of formation fluids and gases from the well to its surroundings

5.1.49

yellow pod

one of two subsea control system pods that sends hydraulic fluid to activate BOP components (also see blue pod)

5.2 Abbreviations

The following abbreviations are used in this document.

5.2.1

AAV

annulus access valve

5.2.2

APB

annular pressure buildup

5.2.3
BPV
backpressure valve

5.2.4
BHA
bottomhole assembly

5.2.5
BHCT
bottomhole circulating temperature

5.2.6
BHP
bottomhole pressure

5.2.7
BHST
bottomhole static temperature

5.2.8
BOD
basis of design

5.2.9
BOP
blowout preventer

5.2.10
BSR
blind shear ram

5.2.11
C/K
choke and kill

5.2.12
CRA
corrosion resistant alloy

5.2.13
CT
coiled tubing

5.2.14
DP
drillpipe

5.2.15
DPS
dynamic positioning system

5.2.16
DW
deepwater

5.2.17
ECD
equivalent circulating density

5.2.18
EDP
emergency disconnect package

5.2.19
EDS
emergency disconnect sequence

5.2.20
ESP
electrical submersible pumps

5.2.21
ETG
expandable tubular goods

5.2.22
FIT
formation integrity test

5.2.23
FOSV
full opening safety valve

5.2.24
FPSO
floating, production, storage, and offloading

5.2.25
HP/LP
high pressure/low pressure

5.2.26
HPWH or HPWHH
high pressure wellhead/high pressure wellhead housing

5.2.27
HTH
horizontal tubing hanger

5.2.28
ID
inner diameter

5.2.29
ISO
International Organization of Standardization

5.2.30
ITC
internal tree cap

5.2.31
LMRP
lower marine riser package

5.2.32
LOT
leakoff test

5.2.33
LPWH
low pressure wellhead housing

5.2.34
LTP
liner top packer

5.2.35
MASP
maximum anticipated surface pressure

5.2.36
MAWP
maximum anticipated wellhead pressure

5.2.37
MOC
management of change

5.2.38
MODU
mobile offshore drilling unit

5.2.39
MUX
multiplex

5.2.40
MYS
minimum yield stress

5.2.41
NACE
National Association Corrosion Engineers

5.2.42
NAF
non-aqueous fluid

5.2.43
OD
outer diameter

5.2.44
PBR
polished bore receptacle

5.2.45
QA
quality assurance

5.2.46
QC
quality control

5.2.47
ROV
remotely operated vehicle

5.2.48
RP
recommended practice

5.2.49
RU
rig-up

5.2.50
SCSSV
surface controlled subsurface safety valve

5.2.51
SSTT
subsea test tree

5.2.52
SWA
stop work authority

5.2.53
SWF
shallow water flow

5.2.54
TD
total depth

5.2.55
TLP
tension leg platform

5.2.56
TOC
top of cement

5.2.57
VIT
vacuum insulated tubing

5.2.58
VIV
vortex-induced vibration

5.2.59
WBM
water-base mud

5.2.60
WOC
waiting on cement

6 Deepwater Activities and Rig Systems Overview

6.1 General

Deepwater Activities and Rig Systems consist of operations conducted in DW to construct wells and conduct operations to produce hydrocarbons. Though outside the scope of the document, a brief description of production operations is included for background information.

The production facility in DW may be bottom supported (e.g. fixed platform or compliant tower), vertically moored (e.g. tension leg) or a floating system (e.g. SPAR, Semi-Submersible or Ship Shaped). Production may be processed on the production facility prior to export from the production system to a tanker or through an export riser and pipeline system. Production comes onboard the production facility through production risers. The production risers may tie directly to a DW Well or to a flowline gathering system which is tied to one or more sub-sea wells.

Wells used in DW may be designed for various purposes such as:

- Exploration;
- Appraisal;
- Well testing (short or long term);
- Production or injection, (subsea well or tied-back to a dry tree production system such as a TLP or spar);
- Utility (monitor or relief well).

Water depth, well depth, and well type vary widely in the deepwater operational areas. The rig may be required to run very heavy loads (approaching or exceeding 1.8 million pounds) and may be operated in water depths exceeding 10,000 feet. Weather considerations (i.e., hurricanes) and infrastructure proximity (i.e., pipelines or platforms that could be affected by rig movement or dragging anchors) may also determine rig type and mooring. DW has evolved to several types of rigs for common use. For drilling and completion activities with floating rigs and subsea BOP systems, the typical rig and system options are:

— Rig type:	Drillship or semi-submersible
— Stationkeeping method:	Dynamically positioned or moored
— Blowout preventer control system:	Piloted hydraulic or electrohydraulic (multiplex)
— Subsea tree type:	Vertical or horizontal tree

When designing a well, certain aspects of the design may assume a particular type of rig, typically moored or dynamically positioned. However, the possibility that a different type of rig will be used to work on the well, sometime during the life cycle of the well is fairly high in some water depths, and this possibility should be taken into account during the design process.

6.2 Rig Options

DW rigs are usually ship-shaped (drillships) or semi-submersibles with two (or more) pontoon hulls. Alternate configurations may also be used. Drillships and semi-submersibles may be dynamically positioned or moored. Wells can also be drilled in deep water using a platform rig installed on a floating production platform; however, this configuration is outside the scope of this document.

The water depth rating of DW rigs is ultimately limited by the installed marine drilling riser tension capacity or mooring system capacity. The amount of required marine drilling riser is dependent on the water depth, marine drilling riser buoyancy used, environmental conditions, and maximum mud-weight required.

6.3 Stationkeeping System

DW rigs maintain stationkeeping (stay located over the well's location on the seafloor, within some radius, so that the tension load on the riser is managed) by using either a mooring system or a dynamic positioning system (DPS).

6.3.1 Mooring System

Mooring systems are designed to keep rigs on location by exerting a restoring force on the rig when metocean conditions push the rig away from its station over the well. Large chains or lines are attached to anchors in the seabed on one end and to the rig on the other end. Several different types of mooring systems include conventional catenary (e.g., chain), semi-taut (e.g., chain/wire), and taut (e.g., synthetic rope) can be used with DW rigs.

The design factors vary for a mooring system depending on the metocean conditions and the potential damage to nearby facilities. A single exploration well most likely has lower design requirements than a multi-well program that will require an extended drilling period with environmental extremes. Likewise, a well drilled near a tension leg platform (TLP) spar facility or major pipeline may have a more robust design than a remote location. A limit-state analysis and risk assessment are integral considerations when assessing mooring systems. See API RP 2SK for additional information about mooring systems.

Special precautions are required when mooring systems are deployed in the vicinity of other assets such as moored surface facilities (e.g., TLP; spars; or floating production, storage, and offloading (FPSO) systems), and subsea infrastructure (e.g., pipelines, flowlines, and manifolds). Mooring system deployment considerations include the potential damage caused by dropping anchors, dragging anchors, or collision with adjacent facilities.

6.3.2 Dynamic Positioning System (DPS)

DPSs are commonly used for stationkeeping on DW drilling rigs. The rig offset-induced bending loads in the marine drilling riser system, subsea BOP, wellhead connector, subsea wellhead, and structural casing loads have the potential to be higher for DPS versus a moored rig system in the same water depth. This is because the assumed rig offset and associated loads that occur with a failure of the DPSs are higher than the failure case for a moored system.

Dynamically positioned drillships and semi-submersibles optimize stationkeeping and reduce vessel motion by keeping the bow pointed in the direction of the prevailing currents, waves, and wind.

The rig offset-induced bending loads can be an especially important consideration if a well was initially planned to be drilled using a moored rig and is drilled or re-entered using a dynamic positioning-style rig. When designing the structural capacity of the well, consider the future needs to have the flexibility to use a DP rig to drill, complete, or re-enter the well.

See API RP 2SK for additional information on DP rigs.

6.3.3 Metocean Criteria and Loading

Metocean conditions at, or near, the location of a DW well are an important component in the well design and operation. In general, metocean analysis considers the statistical probability of a storm event impacting the well's location. Important metocean phenomena to be considered are primarily wind, wave, and current, with other parameters, such as tides having a secondary effect. These phenomena are converted into loads applied to the rig and its riser to determine the rig's suitability to work at the location during the anticipated season(s). These loads can sometimes be managed or minimized by changing the heading of the rig or by adjusting the tensions on different anchoring lines.

Seasonal variation of metocean conditions is a key consideration for most locations. There may be significant differences in the metocean conditions during tropical or winter-storm events versus day-to-day operations. A consequence is that the range of metocean conditions that the rig stationkeeping system should be able to withstand may differ greatly if the rig is drilling a short-duration well during the more benign part of the calendar, compared with an extended drilling campaign stretching over multiple years in the same location. Examples of considerations include: rig survivability, riser survivability, anchor tension or DP rig heading for ship-shaped vessels, watch circles, and evacuation procedures.

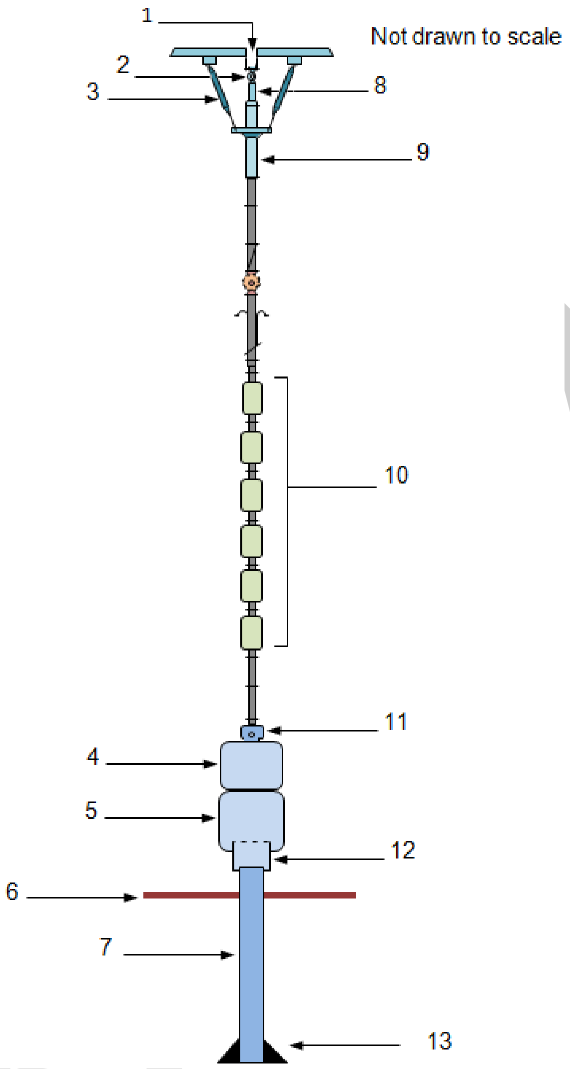
The importance of the currents is generally enhanced in a DW well versus a conventional well. Tidal currents are typically weak in DW, but circulation currents can be quite significant. Circulation currents are relatively steady, large-scale features of the general oceanic circulation. An example is the Loop Current in the Gulf of Mexico, where surface velocities can be in the range of approximately 1 to 2 m/s (2 to 4 knots) at the surface, declining with water depth. While relatively steady, these circulation features can meander and intermittently break off from the main circulation feature to become large-scale eddies or rings, which then drift at a speed of a few kilometers per day. Velocities in such eddies or rings can approach or exceed that of the main circulation feature. Circulation currents generally will not change in magnitude or direction in a dramatic fashion, i.e., changes will typically be gradual (order of days). Rossby waves are currents with period of several days that may occur near escarpments (such as the Sigsbee escarpment). They may generate up to 3.6 knots at the surface with 2 knots at the mudline. Storm currents can be significant. For all types of currents the profile of the current within the water column will be very important.

See API Bulletin 2INT-DG for guidance on hurricane-induced conditions and API RP 2MET for metocean conditions.

6.4 Marine Drilling Riser System

The rig is connected to the subsea wellhead with the marine drilling riser system. The riser is a conduit for equipment and fluid circulation between the rig and the seafloor. The riser system supports the tension load applied to keep it aligned between the rig and the wellhead, along with the weight of the control lines and service lines. The riser system includes smaller, high-pressure choke and kill (C/K) lines that facilitate high-pressure circulation and well control operations. The riser system conveys the control signals that cause the BOP and EDS systems to function and actuate; these control lines may be electrical multiplex (MUX) system or piloted hydraulic. Specialty components (e.g., slip joints and slip ring) at the top of the riser system allow the rig to move up and down and to rotate relative to the riser. Additional information can be found in API RP 53 and API RP 16Q.

Figure 6.1 provides an example of a marine drilling riser system.



Key

1	diverter housing
2	upper ball or flex joint
3	tensioners – wire rope or direct-acting
4	LMRP
5	BOP stack
6	mudline
7	conductor casing
8	telescopic joint inner barrel
9	termination joint/outer barrel
10	buoyed joints
11	riser adapter and lower flex joint
12	wellhead
13	casing shoe

Figure 6.1: Marine Drilling Riser System Example

6.5 BOP System

A subsea BOP system has four primary functions:

a) Kick control – stop an influx and circulate out the influx;

b) Provide the ability to shear drillpipe to allow rapid release of the lower marine drilling riser package (LMRP) from the lower BOP stack;

c) Provide a mechanical barrier to replace the loss of hydrostatic pressure in the event of a drilling riser disconnect;

d) Provide a means of pressure testing down hole tools, well casings, and wellbore seal elements.

The subsea BOP incorporates multiple elements designed to close around the different sizes of drillpipe, casing, or tubing used in the well construction process. This allows circulating an influx out of the wellbore through the (C/K) lines. The BOP also provides the functionality of testing wellbore equipment (e.g., casing, cement, packoffs, etc) by closing BOP elements and valves, applying pressure down the C/K line and monitoring response at the rig floor.

Blind shear rams (BSRs) can shear drillpipe or tubing and seal off the wellbore. However, some shearing elements that can shear larger diameter casing are not designed to seal off the wellbore at anticipated conditions based upon stack conditions and ratings. For any given well program, the BOP stack will be configured with an appropriate number and styles of ram-type BOPs to close in on the drill strings and work strings that will be run through it. Note that all tubulars may not be shearable due to size, wall thickness, or material properties.

The BOP stack consists of two sections.

a) The LMRP contains one or more annular-type BOP(s), which can close and seal on a wide range of pipe sizes. It is important to note that annular sealing elements are the most versatile sealing elements in the BOP, but they cannot be relied on to seal the wellbore when there is no pipe across the BOP. The LMRP contains the control pods and allows for the riser to be disconnected from the BOP stack.

b) The lower BOP stack contains ram-type elements and may contain an annular BOP. These elements can include:

    - Fixed-pipe rams designed to seal on a single designated pipe size;
    - Variable-bore rams designed to seal on a range of pipe sizes;
    - Shearing rams designed to sever a range of pipe sizes, which may not seal;
    - BSRs designed to sever drillpipe or tubing and seal-off the wellbore.

Sealing elements (annulars or rams) are designed to seal against pressure exerted from the wellbore below the BOP. It is possible on some rigs to use an inverted ram or a specially designed bi-directional ram to hold pressure from above to eliminate the need for a test plug during BOP pressure testing.

The C/K line system is considered part of the BOP system. The C/K lines provide a means to circulate fluids into or out of the BOPs, circulate out a kick, monitor pressures, and test BOPs. In deeper water depths, using large inner diameter (ID) lines may prove beneficial by reducing equivalent circulating density.

Subsea BOP stacks contain BOPs and valves joined together with either flanged, studded, other end connectors, or clamp hub connections. The main stack body is subjected to bending loads from the marine drilling riser. C/K line outlets are subjected to bending loads from the pressure end loads applied to the ID of the C/K line at the lowermost valve. The bending resistance of BOP connections is reduced as internal pressure increases. Additional information about API Flange connections can be found in API RP 6AF, API TR 6AF1 and API TR 6AF2. It is critical that the BOP stack and wellhead system have sufficient structural integrity to withstand the combined pressure, tension, and bending loads. To ensure that BOP component connections do not leak under combined pressure and bending loads, methods of resisting the bending loads may be included in the BOP stack frame design. Additional information about BOP systems can be found in API RP 53.

6.6 BOP Control System

Subsea BOP control systems use piloted hydraulic or electrical signals as the primary means to communicate between the surface control station and the subsea BOP. To provide increased reliability of either type control system, two independent control pods allow either control system path to be selected at the surface control panel. The selected control path to activate BOP functions is through either the blue pod or the yellow pod on the subsea BOP (refer to Figure 6.2).

Piloted hydraulic systems are less complex and are commonly used for BOP systems run in shallow water, but the signal transmission speed limits their use in wells in deeper water. Most DW rigs use electronic BOP control systems based on MUX communication protocols that transmit signals in milliseconds. MUX systems are highly complex, and their multiple hydraulic/electric interfaces require diligent maintenance and testing. For some systems it is important to consider how to maintain battery power in the pod. Modern MUX systems provide multiple levels of system redundancy beyond being able to select the blue or yellow pod control system paths.

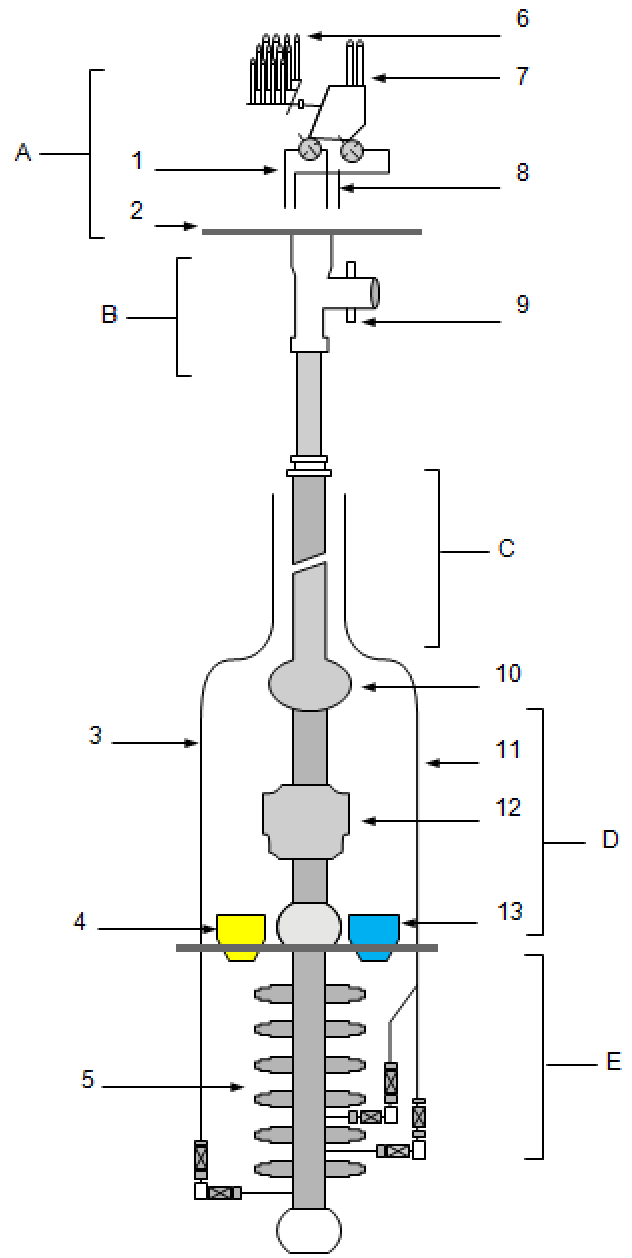
With either piloted hydraulic or MUX systems, the control system is used to direct the flow of BOP hydraulic fluid to various hydraulically operated components (including connectors, sealing elements and C/K line valves) in the BOP system. The control system valve package (commonly referred to as the pod) is where the individual surface-generated control signals activate the selected valve to direct BOP hydraulic fluid to the required BOP function, for example, to close a pipe ram. BOP hydraulic fluid is provided by a local high-pressure accumulator mounted on the BOP stack and/or via a conduit line to a high-pressure accumulator system at surface. For example, a typical 5,000-psi accumulator supply is regulated to supply a lower pressure to operate the individual BOP functions. BOP hydraulic fluid is an environmentally friendly, water-based fluid with soluble oil additives for lubricity and corrosion control. In a typical system this fluid discharges into the sea when individual BOP components are functioned.

Verification feedback to the BOP control panels on the rig includes the incremental volume of BOP control fluid and pressure used to activate a function. Any discrepancy in the expected volume (determined during prior testing of the BOP stack) shall be noted and investigated.

The deadman and autoshear systems must be tested at surface before running the BOP stack.

The BOP stack and control system shall be inspected to verify conformance with design specifications and drawings. Any changes must be approved through a Management of Change (MOC) process and be thoroughly documented.

Additional information about BOP control systems can be found in API SPEC 16D and in API RP 53.



Key

A	control system
B	diverter assembly
C	riser assembly
D	LMRP
E	BOP stack
1	to yellow pod
2	rig floor
3	kill line
4	yellow pod
5	rams
6	accumulator bottles
7	pilot bottles
8	to blue pod
9	diverter
10	flex joint
11	choke line
12	annular
13	blue pod

Figure 6.2: BOP Controls

6.7 Secondary BOP Control System Functions

In addition to the primary BOP closing function, other systems can establish control of the well under specific conditions where redundancy is useful. Refer to API Standard 53 for specific information on surface and subsea test frequency for the emergency disconnect sequence, deadman, autoshear, remotely operated vehicle, and acoustic functions.

6.7.1 Emergency Disconnect Sequence (EDS)

An EDS provides automatic LMRP disconnect when specific emergency conditions occur on a floating drilling vessel. The EDS is designed to ensure that the well is shut in as part of the functional sequence. The EDS is a sequence of functions programmed to initiate after being prompted by pushing the EDS button. There is no system or trigger mechanism that automatically begins the EDS sequence; it must be manually activated by the driller based on the well conditions and vessel-specific operating criteria. An EDS is normally limited to rigs with DP.

The EDS is designed to shut in the well, retract all the stabs, and disconnect the LMRP. EDS sequencing varies depending on the specific system, anticipated disconnect scenario, and input from the vendor, contractor, and operator. Consider testing the EDS sequence prior to running the BOP stack.

6.7.2 Deadman

The deadman is a completely automatic single function that does not require human interface. Deadman systems are also designed slightly differently among manufacturers, but they all achieve the same objective of shutting in the well on the BSR(s) in the event of a loss of hydraulic supply and electrical power to both control pods. There is a fail-open valve blocking the subsea accumulation supply to the BSRs. After this valve senses a loss of hydraulic supply and electrical power from both pods, the valve opens and the BSRs close. There is no other function that occurs. The LMRP is not unlatched, and C/K valves may or may not have pressure supplied as part of the deadman system. The system has to sense a loss of both power supplies. If only one of electrical or hydraulic communication is lost, the deadman will not activate.

6.7.3 Autoshear

In case of an accidental disconnect of the LMRP from the lower (main) BOP stack, most BOP control systems include an automated control system response, sometimes referred to as an autoshear circuit, that triggers the closure of a BSR or rams in the (main) BOP stack to isolate the wellbore. The same autoshear circuit is activated during any planned or emergency disconnect of the marine drilling riser system. The autoshear circuit can be activated by a mechanical-pressure switch activated by the physical movement of the LMRP away from the lower BOP stack, or it can be activated by loss of hydraulic and electrical signals caused by the retraction of the control pod stabs.

6.7.4 Remotely Operated Vehicle (ROV) Panel

The BOP stack shall have an ROV interface panel for secondary controls. Consider the following:

- Hot-stab ports to close BSRs and unlatch the LMRP and wellhead connectors;
- Surface testing of the BOP stack using the ROV interfacing panel before running the BOP stack;
- Testing ROV hot-stab functions using the same flow rate and pressure the ROV will supply subsea to confirm that shuttle valves will shift and sufficient pressure is applied to close and seal the BOP function against pressure.

Additional information for hot-stab ports can be found in API RP 17H, and additional information about ROV interface panels can be found in API SPEC 16D and in API RP 53. Government requirements for ROV interfacing with the stack before running shall be followed.

6.7.5 Acoustic System

Secondary control of key functions can also be provided via an independent acoustic BOP control system that can be activated using any matching portable acoustic control unit on the rig or on any nearby vessel. The reliability of acoustic systems can be adversely affected by thermoclines, currents, and vessel noise (such as during a drive off). See API RP 53 for more information about the acoustic system.

Additional information on BOP control system functions can be found in API SPEC 16D.

6.8 Subsea Wellhead and Production Tree Configurations

The low pressure wellhead housing (LPWH) is welded to the structural casing. It is run with a special running tool when the structural pipe is jetted (or drilled/cemented) in place. A permanent guide base, when used, attaches to the LPWH.

The high pressure wellhead housing (HPWH) is welded to the top of the surface casing and provides an external connector profile to which the subsea BOP stack is attached. It has several internal profiles for casing hangers, running tools, and seal assemblies. It is normally latched to the LPH to increase both bending and rotational resistance.

For wells that will be completed, the subsea production tree is attached to the HPWH. There are two types of subsea production trees: vertical or horizontal. A vertical subsea tree may include a tubing spool.

The type of subsea production tree will have an impact on sequence of completion activities and on the subsea BOP/LMRP configuration for well control during some completion operations.

6.9 Remotely Operated Vehicle Systems

ROV systems may be used in drilling and completion of DW wells. In some operations, multiple ROVs are used to provide redundancy allowing continuous activity in the event of a failure of one ROV. ROVs are used in open water activities before running the BOP stack, secondary activation of the BOP stack, and in completion and abandonment activities. An ROV may include the following functions to support the drilling process:

- Normal/high definition camera for normal viewing and inspection of the condition of equipment, riser, and BOP inspections during operations;
- Hydraulic pump to pump seawater or corrosion prevention fluid or to activate BOP rams;
- Compass to determine relative heading of objects with respect to wellhead;
- Fluid bladder to enable pumping corrosion prevention fluid into wellhead;
- Sonar for detection of objects;
- Multi-function arms to rotate bolts to lock/unlock components and pull/re-install plug-ins;
- Install, remove, and replace ring gaskets on the subsea wellhead and LMRP;
- Tooling packages for subsea equipment;

- Hot-stab capability;
- Hydrate removal;
- Hydrate suppression for pumping glycol or methanol.

See API RP 53 and API RP 17H (or ISO 13628-8) for additional information.

NOTE: Some rigs may use guide lines, which allow a rig-based video system to be run on a cable to monitor operations.

7 Well Design Considerations

Integration of casing design and load cases in conjunction with barrier planning is the basis for all DW well designs. Combined, they contribute to increased reliability and well integrity. This results in a well architecture which permits well objectives to be safely achieved.

7.1 Deepwater Well Architecture

The complexity of DW wells has increased over the years as measured by water depth, well depth, mud-weights, temperatures, and the number of intermediate casing points required to reach the objectives. DW wells now have been drilled in water depths greater than 10,000 ft and to true vertical depths greater than 35,000 ft. Examples of complexities that impact well architecture are:

- *Salt and subsalt hazards such as tar zones or rubble zones;*
- *Subsurface geology including shallow water flow hazards and in-situ hydrates;*
- *Abnormal pore pressure or sub-normal pressures (regressions);*
- *Metocean (including mooring during hurricanes and stationkeeping during loop currents);*
- *Drilling duration, casing wear, and heat checking;*
- *Thermal fluid expansion and trapped annular pressure loads;*
- *Wellhead and hanger load capacities and reduced annular clearance;*
- *BOP limitations (e.g., shear capacity, annular element sealing on large OD casing, impact of annular BOP closing pressures on large OD casing collapse);*
- *Directional requirements;*
- *Presence of* H_2S *(e.g., water flooding).*

DW well designs have subsequently changed to safely meet challenges faced in subsurface geology and drilling hazards. A new generation of DW rigs was constructed to meet the demands required to drill the ultra-deep DW wells. Higher hoisting capabilities and increased pump capacity were some of the features incorporated on the new rigs. To address increased complexity, a variety of well architectural designs and requirements have emerged:

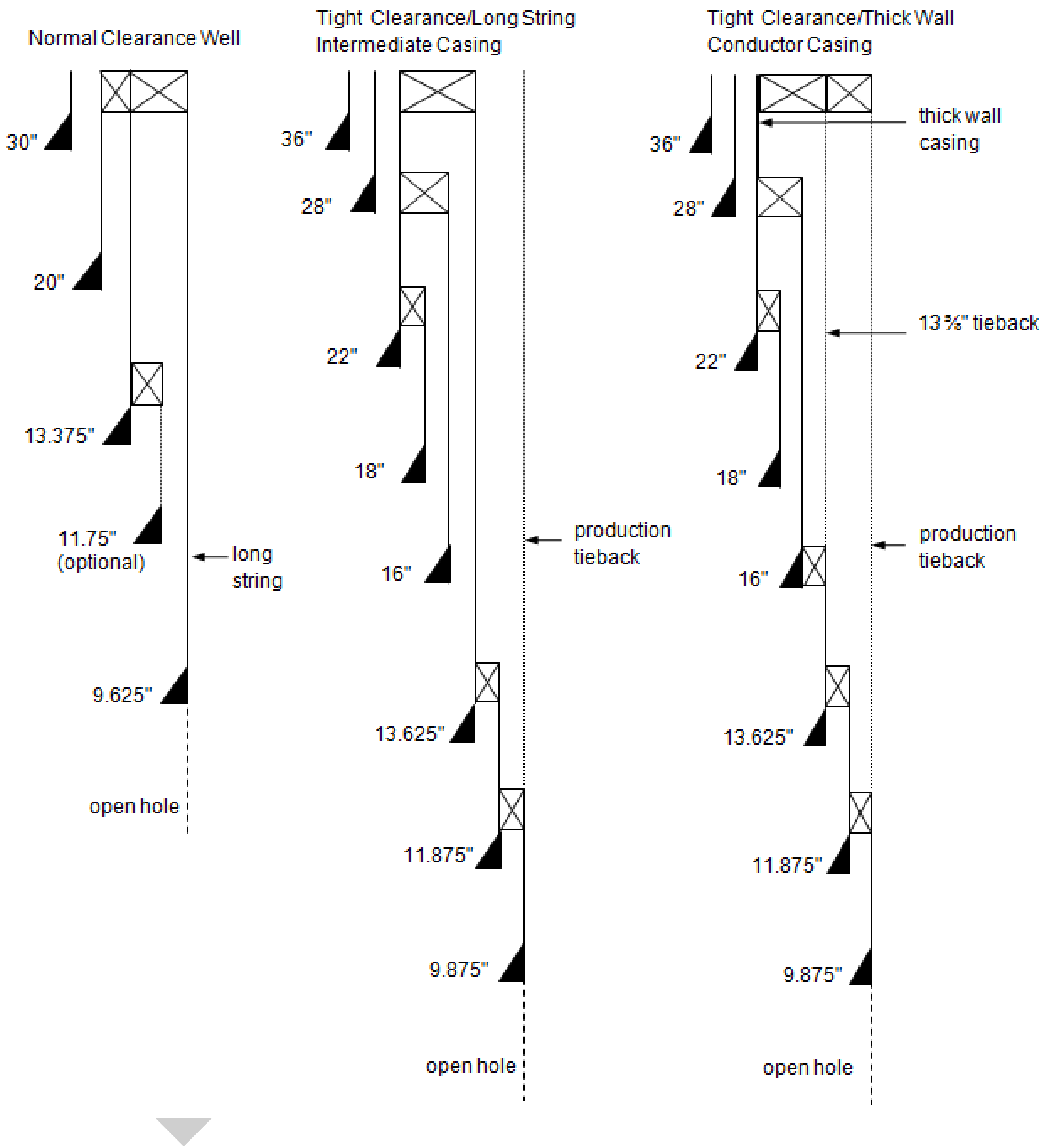
- The deep wells and higher mud-weights require upsizing drillstrings (e.g., from 4½- or 5-in. OD drill strings to 5½-, 5⅞- or 6⅝-in. OD drill strings) to accommodate the increased axial loads and hydraulics.

- The 13 ⅝-in. casing was then needed at the former 9⅝-in. casing depths to reduce the annular friction pressures to acceptable levels.

- Setting the 13⅝-in. casing deeper in the well required additional large outer diameter (OD) casings with slim connections (e.g., 18-in. and 16-in.) and wellhead modifications to run more strings inside the same 18¾-in. BOP stack.

- New generation of landing strings, casing tools, and slips were developed to handle the high casing loads.

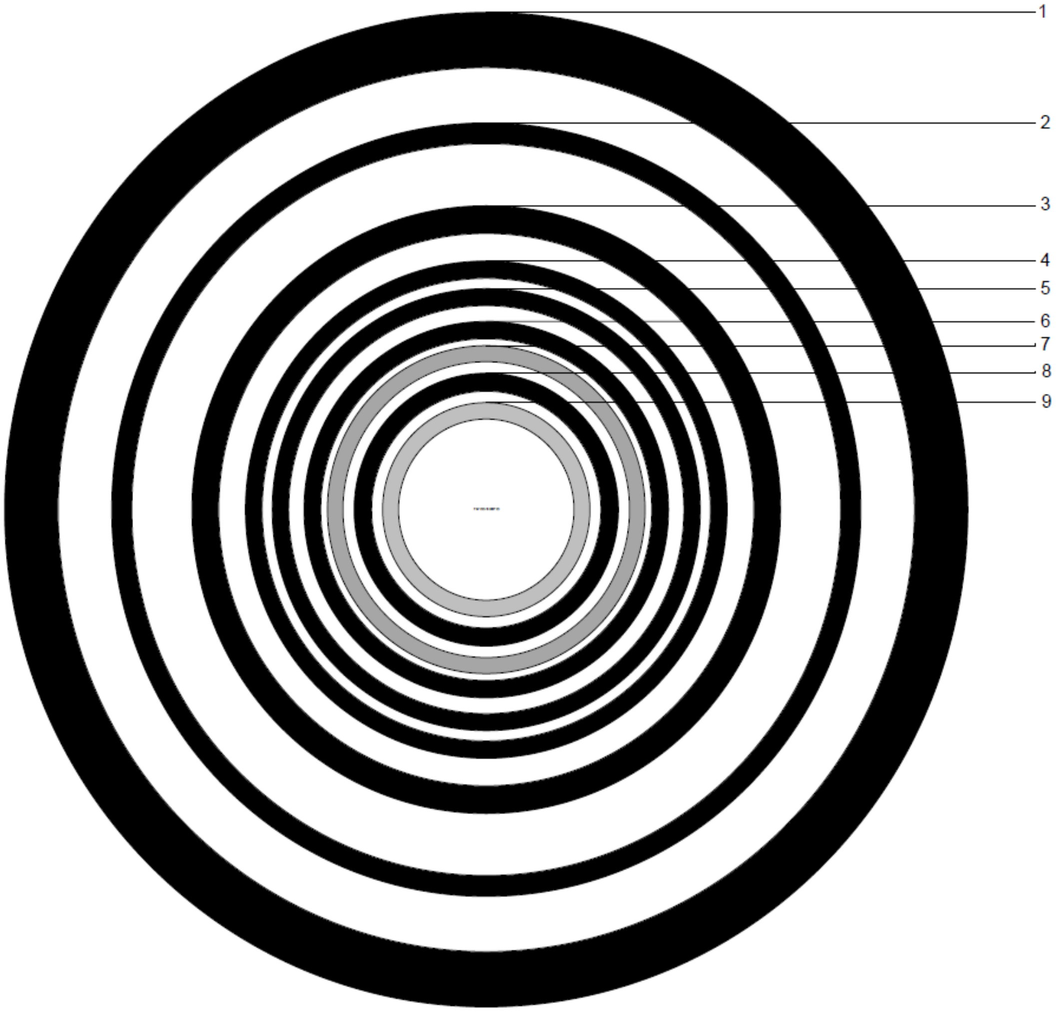
Key physical limitations of the drilling rig that impact well architecture are its capacity and ratings (e.g., mud pits, variable deck load, derrick hoisting rating and racking capacity, marine drilling riser tensioner capacity, power, BOP stack size, pressure rating and shear capabilities, etc.). Most DW mobile offshore drilling units (MODUs) are equipped with an 18¾-in. BOP stack, which effectively limits the size of the first string run below the HPWH. Different types of DW casing programs are used to safely achieve well objectives in different downhole conditions. Three possible DW casing programs are illustrated in Figure 7.1. These are only examples of different casing programs, and they do not capture all of the possible variations in DW well architecture. Please refer to Sections 7.1.1, 7.1.2.1, and 7.1.2.2 for more details.



NOTE: The size and number of strings varies to meet geological conditions, some strings are optional, and not all possibilities are shown. Dotted lines indicate potential tiebacks (9⅞ in. may be hung in 13⅝ in. on high pressure wells). Dashed lines indicate possible casing sections or open hole sections.

Figure 7.1: Well Architectural Examples

Figures 7.2 and 7.3 are cross sections of example wells that illustrate the increased well complexity for a tight clearance casing architecture versus a normal clearance casing architecture. These examples are intended to illustrate the issue of casing and liner clearance. As shown in Figure 7.1, some of the strings can be run as casing, liners, or tiebacks depending on the selected well architecture.



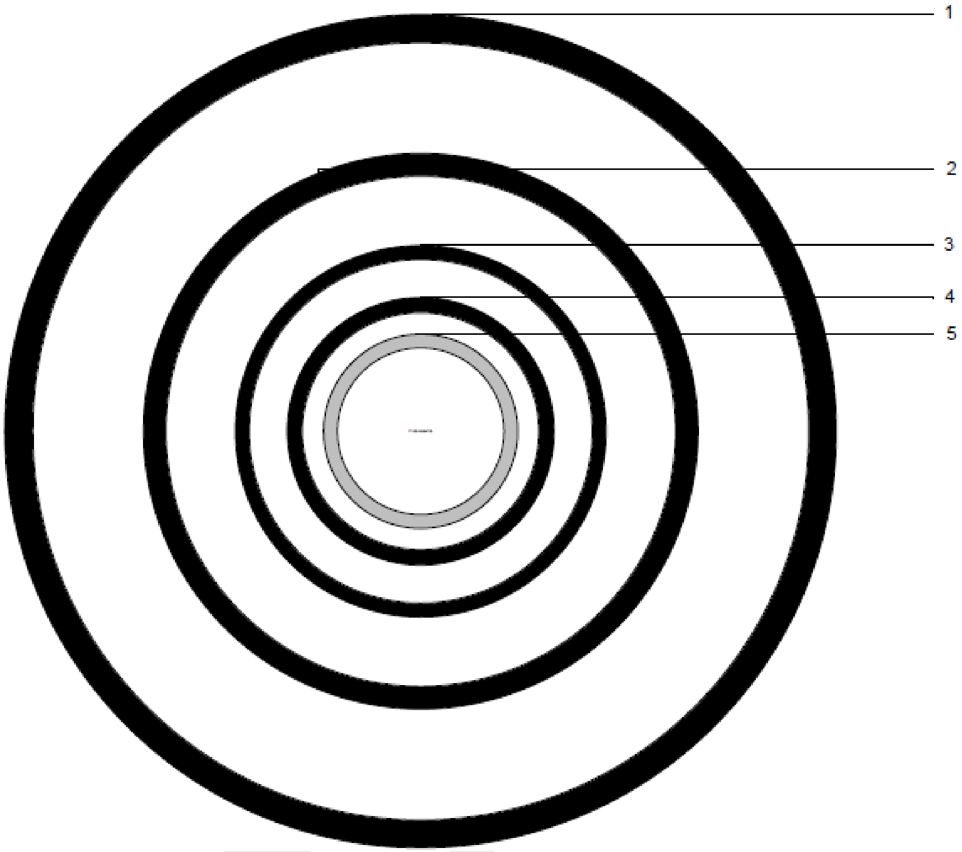
Tight-Clearance Deepwater Well

(Black is casing, Grey is liner, and White is annulus)

Key=OD

1	36 in.
2	28 in.
3	22 in.
4	18 in.
5	16 in.
6	13⅝ in.
7	11⅞-in. liner
8	9⅞-in. tieback/liner/long-string
9	7¾-in. liner

Figure 7.2: Tight-Clearance Casing Schematic with 36-Inch Structural Casing



Normal-Clearance Deepwater Well (benign environment)

(Black is casing, Grey is liner, and White is annulus)

Key=OD

1 30 in.
2 20 in.
3 13⅜ in.
4 9⅝ in.
5 7-in. liner or long-string

Figure 7.3: Normal-Clearance Deepwater Casing Schematic with 30-Inch Structural Casing

7.1.1 Normal-Clearance Casing Well Plan

This example well plan is employed globally in many regions that have low pore pressures relative to fracture gradients and require few casing points to reach total depth. Normal-clearance casing well architecture permits the use of standard hole sizes and casing with coupled connections. It usually requires no under-reaming or tight-clearance casings (e.g., no flush or semi-flush connections).

7.1.2 Tight-Clearance Casing Well Plan

Tight-clearance well architecture was developed to increase the number of casing points available compared to normal-clearance casing well plans. This enabled drilling DW wells where narrow margins exist between fracture gradients and pore pressures. This requires numerous casing points to achieve the objective depth safely.

7.1.2.1 Tight-Clearance/Long-String Intermediate Casing

The tight-clearance/long-string intermediate casing well architecture combines a series of casing strings suspended and sealed at the wellhead with one or more intermediate liners hung below the casing strings. The large-diameter intermediate casing landed in the wellhead permits more liners below it while having sufficient burst pressures to drill to total depth (TD). This architecture satisfies the need for additional shoe formation strength capacity while minimizing the equivalent circulating density (ECD) increase due to running the smaller diameter strings as liners instead of long-strings. This design is the most common and may result in high axial loads when running the intermediate casing string.

7.1.2.2 Tight-Clearance/Thick-Wall Surface Casing

Tight-clearance/thick-wall surface casing (which is attached to the high-pressure subsea wellhead housing) well architecture has been developed. This design includes thick-wall, high-strength wellhead extension joint or joints with a casing hanger adaptor(s) common for the18-in. and 16-in. intermediate casing welded into the thick-wall casing. The casing hanger adaptor permits the hanging and sealing of a mandrel-style casing hanger and seal assembly.

Some designs have the supplemental adapter as part of the high-pressure housing extension joint, while others may include several thick-wall surface casing joints between the subsea wellhead supplemental adaptor and the high pressure wellhead housing (HPWHH). This may simplify plug and abandonment operations.

The latter design can expose additional large OD, welded connectors to the pressures and temperatures at total depth. It also reduces the number of annuli at the wellhead which may affect the APB design. Table 7.1 lists and describes typical casing types.

Table 7.1: Typical Casing Types and Description

Casing	**Description**	**Normal Clearance Casing OD (inches)**	**Tight Clearance Casing OD (inches)**
Structural (Conductor)	Large OD casing; jetted in or drilled and cemented	30	36

Secondary Conductor	Additional casing run below structural casing (i.e., for shallow flow risks)	N/A	28 or 26
Surface	Casing including high pressure wellhead housing (first casing string attached to subsea BOP stack)	20	22
Shallow Intermediate Liner	Large diameter casing normally run as a liner and hung in a profile in the surface casing (18 in. may be called “surface extension” by regulators)	N/A	18 and/or 16
Intermediate Casing	Long casing string with casing hanger in the subsea wellhead housing	13⅜	13⅝
Intermediate Liner	Liner hung below intermediate casing/liner	N/A	13⅝ or 11⅞
Drilling Tieback	Casing run from top of liner to the subsea wellhead housing (i.e., for increased pressure capacity and/or casing wear considerations)	N/A	13⅝ optional
Production Casing	Full string of production casing from below the objective interval with casing hanger in the subsea wellhead housing	9⅝	N/A
Production Liner	Production casing run from below the objective section and hung in the intermediate casing or intermediate liner	N/A	9⅞
Production Tieback	Production casing run from top of the production liner to the subsea wellhead housing	N/A	10¾ x 9⅞

NOTE: These are examples only. Each well may have variations in number of casing strings and sizes. Naming conventions may vary in other regions. The thick wall surface casing designs may allow 13⅝ in. to be run as a liner and not tied back.

7.1.3 Completion Architecture

The objective of the completion architecture is to achieve the desired production or injection rates over the life cycle of the well. This completion architecture forms the basis for selecting the production casing size.

These items may affect the design of the completion architecture:

- Tubing size to achieve the desired well inflow rate;
- Sandface completion design;
- Size of upper completion components (surface controlled subsurface safety valve [SCSSV], inflow control devices, injection subs);
- Recompletion/fishability of completion components;
- Control lines and chemical injection lines;
- Artificial lift design;

- Flow assurance requirements;
- Sulfide stress cracking and corrosion considerations;
- Completion fluids compatibility.

Note: See section 9 of this document for special considerations for completions.

7.1.4 Production Liner or Production Long-string

There are a number of issues to consider when selecting either a production liner, production liner tieback, or a long-string alternative for the production casing string. The effect of the configuration chosen on the total system reliability will depend on the specifics of the well. In some situations one design may provide a higher long-term reliability than another. The solution chosen must account for the expected pressures and combined loads while minimizing risks.

7.1.4.1 Liner Considerations

Wells experiencing severe loss circulation with gas-prone intervals are good candidates to consider for using a liner with an optional tieback, as needed. This option allows use of a liner top packer (LTP), which may be set after cementing. The LTP provides a mechanical barrier that isolates the openhole section after it is set. Testing a LTP does not confirm cement isolation.

The liner option allows the casing to be hung at any depth if the string does not reach bottom. It also allows pipe rams to seal around drillpipe once the liner is past the BOP stack.

The liner hanger system should be selected based on the expected pressures and combined loads. Close tolerance liner hangers (e.g., 13⅝ X 11⅞ and 11⅞ X 9⅝) may have reduced burst and collapse ratings when compared to the high-strength tubulars used in many liners. If increased ratings are required, consideration can be given to hanging the liner in the next larger string or to other alternatives (e.g., tieback receptacle placed below hanger to increase system rating).

Additionally, consider the ability to execute a successful cement job and obtain adequate isolation. Depending on well conditions and equipment, liners may be moved during cementing, which can increase mud-to-cement displacement efficiency in the annulus. The shorter annulus section (open hole remains the same but the cased hole section is reduced with a liner), combined with the concern for bringing cement above the liner, typically results in less cement volume being pumped versus a long-string option. Liner hanger designs and configurations vary which can result in annular flow paths that can yield higher or lower frictional pressures when circulating. Depending upon liner hanger and well geometry, a liner solution could have a lower ECD, which may increase the probability of a obtaining a successful cement job. Refer to API RP 65-2 for more in depth discussion of cementing considerations

Well designs that include production liners may require a production tieback to accommodate the producing pressures and combined loads. The addition of a production tieback increases the complexity of the well construction. Consideration needs to be given to: the tieback stem and liner polished bore receptacle interface design; installation space-out to engage the tieback stem seals when the casing hanger is landed in the wellhead; tieback anchoring method to limit seal movement during the well's life cycle; and a trapped annulus leading to an introduction of additional APB loads.

7.1.4.2 Long-String Considerations

When using a long-string for the production casing, evaluate the following when developing the overall barrier maintenance in the plan:

- Slurry design and placement;
- Effect of lost circulation during cementing;
- Potential for annular gas migration resulting in additional casing and wellhead loads;
- Wells that experience severe losses during cementing can need additional verification that the slurry was effectively placed to act as a hydrocarbon barrier;
- Casing hanger lockdown requirements (Refer to Section *8.2.1 Subsea Wellhead Casing Hanger Locking Device*);
- Verification of effective slurry placement;
- Swellable packers or inflatable packers in the annulus.

Note: Cured cement can be considered a verified barrier if designed for the well conditions and if job data shows that it has been properly placed i.e., volumetric returns or lift pressures. See Section 5.1.42 for the definition of a verified barrier.

Evaluate the difference in exposure time with non-shearable items across the stack when selecting either a liner or long-string option. See Section 10.2.2.1 *Running Non-Shearable Items through the BOP* for additional information.

In addition, consider the ability to execute a successful cement job, thereby obtaining adequate isolation. Long-strings are usually landed in the wellhead housing prior to cementing; therefore, the lack of pipe movement reduces the mud-to-cement displacement efficiency in the annulus. Furthermore, as a result of long and tight annular clearances, additional ECD may be experienced, further complicating the cement job. Refer to Table B.3 for cement barrier confirmation following the cement job. In the event of a questionable long-string cement job with hydrocarbon zones present in the annulus, a cement evaluation log will be run to verify cement placement above hydrocarbon zones before removing the BOP stack or reducing the hydrostatic barrier below formation pressure. Note: the cement evaluation log is run only to verify cement placement and not the quality of the cement's zonal isolation performance. API 10TR1 provides detailed guidance on cement evaluation practices.

Refer to API RP 65-2 for more in depth discussion of cementing considerations.

7.2 Barrier Philosophy

This section describes how physical barriers and operational barriers contribute to well system reliability with respect to well control. It describes the principles, processes, and procedures for planning and implementing barriers. In this recommended practice, barriers are defined as components or practices that contribute to the reliability of the well system design by preventing uncontrolled flow during all of the well's life cycle phases.

Apply the barrier philosophy to each potential flow path, while bearing in mind the consequences of a loss of well control. Regulatory requirements related to barrier implementation shall be followed.

7.2.1 Introduction

A petroleum well is a pathway through subsurface formations to a reservoir target that potentially contains hydrocarbons. As the pathway is constructed, barriers are installed to prevent undesired flow from these formations through other paths (i.e., surface or into well) for the life cycle of the well. If a commercial quantity of hydrocarbons is discovered, final casing is set and a completion is installed to safely control this desired flow of production to the surface while still preventing undesired flow.

A system of multiple barriers is used to achieve a high level of reliability in avoiding uncontrolled flow during well construction, operation, and abandonment. The historical reliability of subsea well operations proves that the philosophy of multiple barriers is effective. The well reliability that is achieved is a function of the combined reliabilities of each individual barrier and not the result of the infallibility of a single component.

The designer's objective is to achieve a high level of well reliability by combining operational and physical barriers. Physical barriers contribute to a high level of reliability. Operational barriers depend on human recognition and response; however, when combined with well-designed and properly installed and tested physical barriers, operational barriers significantly increase well reliability. Operational barriers also include institutional controls such as casing design standards and policy manuals.

The reliability of any physical barrier is increased if its integrity is confirmed by testing to anticipated loads (i.e., in the direction of flow), after the barrier is deployed. Sometimes testing cannot be used to confirm barrier integrity because potential load directions or anticipated loads cannot be simulated within the well. In these situations, more emphasis is placed on maximizing the reliability of the barrier by increasing quality control during design, manufacturing, and installation. If a barrier cannot be tested, its placement should be verified to the degree possible. Additionally, operational barriers may be used to ensure that any failure of a physical barrier is detected and managed without loss of well control.

Physical barriers contribute the most to the well reliability because of their very low failure rates. Operational barriers increase the reliability of the well system. They become particularly important when the physical barrier system cannot be tested.

General recommendations that may be considered by the well designer and operations personnel are:

a) Assume that any single well barrier may fail, even those that are confirmed. Consider the potential consequences of failure of each well barrier and the required contingencies and responses.

b) Understand which operational barriers are in place when the rig is working on the well, regardless of the number of physical barriers in place or whether the barriers have been confirmed.

c) If a physical barrier cannot be verified by testing it to its full anticipated loads, verify placement by one of the following alternatives:

    1) Collect data or observations during physical barrier installation that verify effective execution of the installation;

    2) Use in-place inspection of the mechanical barrier or verify the physical barrier by testing it to a lower load or in the opposite direction of the maximum design load;

    3) If placement of a physical barrier cannot be verified, additional operational barriers may be used to enhance the well system reliability. To enhance their effectiveness, operational barriers may be assessed with measurement, workflow, training, and drills.

d) Review the barrier plan as part of a management of change (MOC) process if well conditions change.

e) Ensure personnel understand that a decision not to deploy a planned operational or a physical barrier due to unexpected conditions may increase the likelihood of well system failure.

f) If a physical barrier is found to be deficient during the course of operations and it cannot be repaired, reassess the remaining well system reliability. The loss of a physical barrier may cause a significant reduction in the well reliability. Consider supplemental physical barriers or operational interventions as a part of the MOC process.

7.2.2 Barrier Planning

A barrier plan should be developed that identifies flow paths and the barriers that prevent flow along each path, during each phase of the well construction Well sketches illustrating the barriers in place for each operational phase should be included. Barrier planning includes determining the operating conditions to which various well barriers will be subjected over its intended lifetime and ensuring that the performance rating of the chosen barrier system is suitable for that well environment. This includes multi-axial loads and environmental conditions during routine conditions, as well as planning for any extreme operating conditions.

The key barriers in a well change continually during the well construction process. The drilling process is a sequence of steps that expose formations to the wellbore while using the hydrostatic pressure of the drilling fluid to prevent flow and then isolating the formations behind casing, cement, and other physical barriers. To drill deeper, the casing shoetrack is drilled out (intentionally defeating a portion of the physical barrier system), and the drilling fluid column once again provides well control.

After the final casing is set and cemented, the completion process establishes a flow path from the reservoir into the wellbore and installs and verifies barriers necessary for long-term production or injection. A variety of short-term barriers are employed during the completion, with availability based on the specific operation performed. Following completion, the well is designed to have multiple physical barriers against each potential flow path from the formations.

The number and types of well barriers used varies with the specific operation and may be specified by the governing regulatory body. It is generally accepted that using two physical barriers provides high system reliability. If an operation is performed with fewer than two physical barriers in place, then operational barriers become critical. For example, while drilling in openhole, the hydrostatic barrier of the drilling fluid is the only physical barrier preventing flow to the rig floor. The BOP equipment becomes a second physical barrier when it is closed and sealed. The reliability of the BOP equipment as a physical barrier depends on operational barriers: detecting an influx at the rig, recognizing the need to respond, responding appropriately, and the proper design and functioning of the actuation system to close the sealing elements and valves in time.

Another common operation requiring extra focus on operational barriers is the removal of a physical barrier from the well. An example is drilling out a cement plug or displacing the marine drilling riser to seawater. In these examples, it is prudent to ensure that field personnel understand that the operation involves removing a barrier. If it is assumed that the well will flow when the barrier is removed, quicker reaction time is necessary to maintain the safety and integrity of the operation. Refer to Section 10.2.1 *Fluid Displacement to Non-Kill-Weight Fluids* for more information about displacements.

Permanent or temporary abandonment operations require removing the BOP stack and marine drilling riser. This will result in the loss of at least one and probably two physical barriers (the ability to have a closed BOP and the hydrostatic barrier if the fluid density does not include riser margin). When a well is unattended, operational barriers are not available to contribute to overall system reliability. All planned physical barriers should thus be in place and verified. *The Minimum Barrier Abandonment Requirements for Deepwater* Section in API RP 96 requires two verified physical barriers, one is mechanical and one may be a cement barrier. Refer to Informative Annexes and Section 7.1.4.2 for further explanation.

During ongoing production operations, operational barriers may include monitoring the tubing-by-production casing annulus pressure or monitoring changes in production conditions that could signal a change in the well status, with a resulting impact on overall well integrity.

Annex A: Examples of Barriers Employed During Operations provides examples of common operational scenarios and lists common well barriers associated with each flow path for a scenario. *Annex B: Example Barrier Definitions* provides examples of common barriers and considerations associated with implementing them in the well design for operational scenarios described in Annex A. The format of tables, well schematics, and descriptions of various flowpaths are suggested as a template for communicating a barrier plan for a well operation.

NOTE: The lists of scenarios and well barriers in the annexes are not comprehensive.

7.2.3 Barrier Confirmation

Acceptance criteria shall be established for each barrier. Acceptance criteria define the conditions that must be fulfilled to confirm the integrity of the barrier for its expected operations. Sometimes it is feasible to directly confirm that the barrier is preventing flow by pressure testing, but sometimes barrier performance is confirmed through other observations. Barrier confirmation results shall be documented and retained as required by regulations or by company policy.

7.2.3.1 Integrity of Physical Barriers

Integrity of physical barriers involves these phases:

a) Design (including qualification)

The well designer obtains the capacity or operating rating of the equipment from the equipment manufacturer. Consider the capacity of the combined-direction loads and environmental conditions in the well. Also consider data available from any qualification methods (e.g., finite element analysis [FEA] or physical testing) and whether additional qualification is needed for the application. The well designer is also responsible for selecting the proper materials considering the environmental conditions and planned operating conditions.

b) Manufacture (including inspection)

The equipment should be manufactured according to its design. The manufacture may include inspection or testing of raw materials or finished product.

NOTE: For some well barriers, (i.e., cement mixing) final manufacture is performed at the rig site.

c) Installation in the well

Consider installing the barrier according to documented procedures or field practice. Data collection during installation may be necessary to verify the barrier. In this case, the installation procedures specify the required data collection and acceptance criteria.

d) Pressure testing or verification after the installation is complete

A pressure load may be applied to the barrier to evaluate its proper installation and to simulate an anticipated operational condition. It is not feasible to pressure test some barriers, particularly those placed in an annulus. Only the placement of these barriers can be verified (e.g., record observations during placement and compare to pre-job expectations to demonstrate successful placement).

e) Operation

During continuing well operations, the ongoing effectiveness of some barriers may be monitored or reassessed. In some cases, the absence of pressure indicates that well control is maintained, while in other cases, an initial test can be repeated or a different re-test can be applied.

7.2.3.2 Confirmation by Pressure Testing

The most reliable confirmation of a physical barrier is to pressure test to the expected differential pressure in the direction of flow after the barrier is installed in the well. Criteria defining an acceptable test are generally established by the well designer (examples may include: test fluid, hold time, allowable pressure change, applied weight, or allowable fluid level change).

It is practical to pressure test a newly installed mechanical barrier using the fluid that is in the well at the time of the installation. This fluid is typically the drilling mud or completion brine or water. Often regulations dictate the acceptance criteria for a pressure integrity test. Acceptance criteria may include:

- Pressure change during hold time;
- Visual observation of leak;
- Difference between pressure-up volume and bleed-back volume;
- Visual observation of fluid level.

NOTE: It is good practice to conduct a low-pressure test (~200 psi or 300 psi) before a high pressure test on mechanical components whose design allows their seal elements to be energized by the application of pressure.

7.2.3.2.1 Inflow Testing

An inflow test involves assessing integrity in the direction *into* the well. This typically involves disabling the hydrostatic barrier by reducing the gross effective fluid column to create a net load from the well pressure below a physical barrier. This is typically accomplished by displacing some of the kill-weight hydrostatic fluid out from the well with lower density fluid(s). To limit the quantity of kill-weight fluid displaced from the well and to create a trapped volume to test, the low density fluids are often displaced down a drill string and trapped by a packer set above the physical barrier being tested or, in the case of a test on a wellhead seal assembly, trapped against a BOP test ram or BOP test tool. When planning an inflow test, consider the rating of all of the barriers that will be exposed to the inflow net pressure.

Inflow tests may be conducted several ways. Primary considerations are maintaining well control and determining how to rapidly restore the hydrostatic barrier if a barrier fails during the inflow test.

Example 1: The following generic description illustrates an example of an inflow test using a retrievable packer for testing sub mud line barriers:

a) *Run a packer into the well on pipe to just above the barrier(s) to be tested.*

b) *Make up and pressure test surface lines from drillpipe to choke manifold to the cement unit.*

c) *Displace the inside of the pipe with enough of the less-dense fluid to create the desired under balance (i.e., net differential pressure into the well).*

d) *Set the packer and confirm that it is sealing by pressure testing the annulus of the drillpipe.*

e) *Bleed off the pressure inside the drillpipe to choke manifold. If the barrier(s) appear(s) to be sealing, open the valve completely and monitor flowback volume for a sufficient time to evaluate results (e.g., 30 minutes. Due to thermal effects of mud, a Horner plot may be necessary to evaluate the results of the inflow test):*

1) *If the barriers pass the inflow test, re-pressurize the drillpipe, unseat the packer and reverse out the less-dense fluid, and remove the packer and pipe; if the barriers fail the inflow test, put hydrostatic barrier fluid back into the well.*

2) *Remove the less dense fluid by either (1) reversing it out or bullheading it through the leak or (2) unseating the packer and circulating the influx through the choke.*

NOTE: An inflow test performed on multiple physical barriers in series cannot verify each individual barrier. For example, an inflow test on a multi-valve shoetrack with set cement cannot individually demonstrate performance of the valves or the cement, only that the combination of these barriers is performing. However, the presence of multiple barriers in series increases well reliability.

Example 2: The following generic description illustrates an example of a inflow test for testing a Wellhead Seal Assembly with a BOP test ram:

a) *Run the drillpipe to below the wellhead.*

b) *Rig up the drillpipe to the choke manifold and test the lines.*

c) *Displace the inside of the pipe with enough of the less-dense fluid to create the desired under balance (i.e., typically sea water or non-aqueous fluid [NAF] base oil).*

d) *Close the test ram.*

e) *Close a pipe ram and pressure-up down the choke line between the test ram and the pipe ram to confirm that the test ram is holding pressure. Ensure that the BOP test pressure is greater than the desired under balance. Hold test pressure between the test ram and the pipe ram and monitor the choke line pressure during the under balance test.*

f) *Bleed off the pressure inside the drillpipe to choke manifold at a slow rate and record bleedoff volume versus surface pressure. Once the drillpipe pressure is bled off, monitor flowback volume in the trip tank for a sufficient time to evaluate results (e.g., 30 minutes).*

    1) *If the seal assembly passes the inflow test:*

        i. *Bleed off the pressure between the pipe ram and the test ram.*

        ii. *Re-pressurize the low density test fluid in the drillpipe with the cementing unit to the original drillpipe pressure prior to bleeding off to achieve a pressure balance on the test rams.*

        iii. *Open the test ram.*

        iv. *Reverse out the low density test fluid in the drillpipe with mud through the choke manifold.*

        v. *Confirm that the well is static on the drillpipe and choke line, then open the pipe rams.*

        vi. *Rig down the line from the drillpipe to the choke manifold.*

        vii. *Continue to the next operation.*

    2) *If the barrier fails the inflow test, put hydrostatic barrier fluid back into the well and circulate out any wellbore fluid.*

        i. *Bleed the pressure off between the test ram and the pipe ram to pressure up the choke line.*

        ii. *Re-pressurize the low density test fluid in the drillpipe with the cementing unit to achieve a pressure balance on the test rams.*

iii. *Open the test ram.*

iv. *Circulate out the low density test fluid (determine if any wellbore fluid has entered or is continuing to enter the well after the test) through the choke line with mud. Note: If wellbore fluid entered the well, refer to company well control policy.*

v. *Confirm that the well is static on the drillpipe and choke line, then open the pipe rams.*

vi. *Rig down the line from the drillpipe to the choke manifold.*

vii. *Continue to the next operation.*

NOTE: this test is performed after deeper barriers have been tested. If using NAF base oil, review stack pressure differential limits when external pressure exceeds internal BOP pressure, as some BOP parts may not be designed for external pressure.

Example 3: The following generic description illustrates an example of an inflow test for testing a Wellhead Seal Assembly with a BOP test tool designed to seal in the SS HPWH bore above the casing hanger or bore protector:

a) *Run the BOP test tool on drillpipe to just above the landing point in the wellhead.*

b) *Rig up the drillpipe to the choke manifold and test the lines.*

c) *Displace the inside of the pipe with enough of the less-dense fluid to create the desired under balance (i.e., typically sea water or NAF base oil).*

d) *Seat the BOP test tool in the wellhead.*

e) *Close a pipe ram and pressure up down the choke line between the BOP test tool and the pipe ram to confirm that the BOP test tool is seated and holding pressure. Ensure that the BOP test pressure is greater than the desired under balance. Hold test pressure between the BOP test tool and the pipe ram and monitor the choke line pressure during the under balance test.*

f) *Bleed off the pressure inside the drillpipe to choke manifold at a slow rate and record bleedoff volume versus surface pressure. Once the drillpipe pressure is bled off, monitor flowback volume in the trip tank for a sufficient time to evaluate results (e.g., 30 minutes) :*

    1) *If the seal assembly passes the inflow test:*

        i. *Bleed off the pressure between the pipe ram and then unseat the BOP test tool.*

        ii. *Re-pressurize the low density test fluid in the drillpipe with the cementing unit to the original drillpipe pressure prior to bleeding off to achieve a pressure balance on the BOP test tool.*

        iii. *Close an annular BOP and open the pipe ram.*

        iv. *Reverse out the low density test fluid in the drillpipe with mud through the choke manifold.*

        v. *Confirm that the well is static on the drillpipe and choke line, then open the annular BOP.*

        vi. *Rig down the line from the drillpipe to the choke manifold.*

        vii. *Pull out of hole with the BOP test tool.*

viii. *Continue to the next operation.*

2) *If the barrier fails the inflow test, put hydrostatic barrier fluid back into the well and circulate out any wellbore fluid.*

   i. *Bleed off the pressure between the BOP test tool and the pipe ram up the choke line.*

   ii. *Re-pressurize the low density test fluid in the drillpipe with the cementing unit to achieve a pressure balance on BOP test tool.*

   iii. *Close the annular BOP, open the pipe ram, and then unseat the BOP test tool.*

   iv. *Circulate out the low density test fluid (determine if any wellbore fluid has entered or is continuing to enter the well after the test) through the choke line with mud. Note: If wellbore fluid entered the well, refer to company well control policy.*

   v. *Confirm that the well is static on the drillpipe and choke line, then open the annular BOP.*

   vi. *Rig down the line from the drillpipe to the choke manifold.*

   vii. *Pull out of hole with the BOP test tool.*

   viii. *Continue to the next operation.*

NOTE: this test is performed after deeper barriers have been tested.

7.2.3.2.2 Alternative Testing

The confirmation method of conducting a full-differential pressure test in the direction of flow is not always feasible. The well designer may consider other methods for mechanically testing the barrier such as:

- Pressure test in the direction opposite of flow (if appropriate for the barrier).
- Test to a pressure selected so that some part of the barrier is exposed to the desired maximum pressure differential (also applies to a tubular string integrity test where the pressure load varies considerably over the depth of the well).
- Carefully measure the fluid volume needed to achieve the test pressure. The differential fluid volume that is added to the fluid in the well, combined with the compressibilities of the fluids, can be used to estimate the volume of fluid in the well. This method is often used to check the integrity of a shallow barrier (e.g., plug) in a well that has other barriers much deeper. A much smaller differential fluid volume is required to achieve the test pressure if the shallow barrier provides integrity.
- Slack-off weight of string on a cement plug in a tubular to confirm that the plug has set or hardened as designed (acceptance criteria may involve applied weight and/or permitted penetration depth). This verification method will confirm that cement has set but not that it is a barrier to fluid flow.
- Perform “drill-off test” of a cement plug by assessing the cement strength by the (high) weight on bit needed to drill the plug, or by the (slow) rate of penetration while drilling it, as a qualitative assessment of cement quality. The size of the cement plug pumped may be increased to accommodate the length lost while performing the drill-off test.

7.2.3.3 Verification of Hydrostatic Barriers

For a fluid column to serve as a barrier, the hydrostatic pressure of the fluid must exceed the pore pressure of the formation on which the pressure acts. Hydrostatic pressure is the pressure exerted by a fluid due to the cumulative weight of the fluid above it. This requires a continuous fluid column that is maintained for a sufficient height to exceed the pore pressure. Failure to maintain the fluid column height may cause a pressure underbalance and allow the formation to flow.

Check the density of the fluid and make adjustments, as necessary, to maintain the overbalance. Consider the temperature profile of the well and the impact of temperature on fluid density. Consider pressure changes due to the dynamic effects of fluid movement arising from circulation or pipe movement. Further, where solids-laden fluids are used as hydrostatic barriers under static conditions, evaluate the effects of hole geometry (deviation, hole size, etc.) and exposure time on barrier effectiveness.

The drilling mud hydrostatic pressure from the height of the marine drilling riser can be suddenly replaced with seawater hydrostatic pressure in an event where the LMRP is disconnected (i.e., a drift-off or drive-off scenario). This scenario almost always results in losing hydrostatic pressure sufficient to maintain a barrier to the formation pressure; thus, operational barriers must be in place to ensure that another physical barrier is rapidly established. For dynamically positioned rigs, an emergency disconnect sequence is programmed to actuate the BOP and seal the wellbore with the BSRs when activated by the driller. Note that in some wells, a mud density can be used that maintains an overbalanced condition, even in the LMRP disconnection scenario.

NOTE: If a fluid column contains some length of unset cement, any fluid below the top of cement may lose pressure communication with the hydrostatic of the fluid above as the cement transitions from a liquid to a solid. The pressure exerted by a fluid volume that is located below a cement barrier can be more difficult to determine.

See API RP 65-2 for more details about fluid volume. See Section 7.3.3.2 for additional discussions concerning annular fluids.

7.2.3.4 Verification of Annular Cement Barrier

For set cement in the annulus to serve as a physical barrier to the influx of formation fluids, the cement slurry shall be designed and laboratory-tested for the anticipated well conditions. The cement slurry should be placed in the well using recommended practices and equipment. Field experience has shown that successful placement of properly designed cement slurry can create a reliable annular barrier. However, if data collected during the slurry placement operation indicates that the cement top may not be at the planned depth or that the slurry has other problems, a diagnostic log may be used to estimate the location of the cement top. Certain logs can also attempt to evaluate the strength of the bond to the casing and the formation. Guidelines for achieving zonal isolation using cement are published in API STD 65-2 (including criteria for compressive strength development). Guidelines for using cement as a barrier are listed in *Annex B: Example Barrier Definitions*.

NOTE: Consider loads and environmental changes that may occur on a cement sheath over the life cycle of the well. Typical slurry tests only focus on placement operations and conditions.

7.2.3.5 Assessment of Operational Barriers

Operational barriers include continuous monitoring of the well system, rapid recognition of evidence of an integrity upset, and effective execution of mitigation plans. By their nature, operational barriers cannot be tested like physical barriers. However, it is possible to certify personnel who have completed well control training, assign responsibilities for responding to a well control event, conduct drills to demonstrate readiness and proficiency, and retain records that demonstrate successful execution of institutional controls. Examples include Well Control Certificates and records of operational drills.

7.2.4 Barrier Maintenance

Because any physical barrier can fail, the ongoing effectiveness of barriers is often assessed. The act of reassessing barrier performance is an operational barrier. Detection of a barrier failure normally results in immediate action to address the failure before continuing planned operations.

A re-test of a physical barrier is the highest level of assurance of the ongoing effectiveness of the barrier. Regulations often dictate the retest frequency of equipment. The effectiveness of some barrier systems under operating conditions can be checked by inspection. An example of checking a barrier with in-situ inspection is using a caliper log to measure casing wall.

If a barrier fails, then reconsider the integrity of the overall well system relative to continuing the current operation. Regulations may suggest remedial actions for some types of barrier failure. Consider the following alternatives:

a) Attempt to restore the barrier;

b) Install a different barrier (may be another barrier of the same type or a different type);

c) Reconsider the overall system reliability based on the well's forward plan.

The tables in *Annex B: Example Barrier Definitions* provide examples of barrier assurance and barrier re-establishment after failure for a number of commonly used physical barriers.

7.3 Load Cases – Drilling and Completion Conditions

7.3.1 Tubular and Equipment Design Philosophy

This section describes a common approach to how the well designer determines if a particular tubular string or hardware component satisfies the requirements of the well application. The fundamental processes are similar for both casing and hardware components, and they are similar from company to company. While the details of the processes may differ among companies, using multiple methods can provide successful results.

The fundamental approach is to determine the loads and the environment that the tubular string or component will sustain throughout the well's life cycle, then determine the capacity of the tubular or component in the loading direction and its suitability in the environmental conditions, and finally to compare the loads and capacities. The tubular or component is judged to be acceptable for the application if its capacity exceeds the anticipated load by an appropriate margin and if the material from which it is made is compatible with the downhole service environment.

The first part of the design process is to determine the loads on the tubular or component that are expected throughout its service life. The magnitude of the loads varies widely during different stages of well construction and operation. For example, pressure loads on the casing and hardware are relatively modest for most of the well's life cycle. However, the tubing and other completion components routinely sustain relatively higher pressure loads. Yet for the purpose of designing casing, tubing, casing hardware, and completion components, the well designer usually will use loads that represent maximum load scenarios. The loads might be expected to occur (e.g., the test pressure during a pressure test, the pressure inside the tubing when the well is shut in), or the loads might represent an unlikely but feasible situation (e.g., circulating a kick using the driller's method, pressure in the tubing by casing annulus from a tubing leak). Some load scenarios may be defined with a combination of inputs that is very unlikely to occur in a real well, but provides a convenient way to calculate a maximum load (e.g., 50 percent gas, 50 percent mud as an approximation of a kick load). The examples described in this paragraph all describe internal pressure load scenarios, and the designer will take a similar approach with other load scenarios such as external pressure, tension or compression, torsion, and others.

The second part of the design process is to determine the capacity of the tubular or hardware component. The first step in determining capacity is to define "failure" within the context of the well application. A common example design criterion is the onset of yield. An example of a more extreme design criterion is the loss of structural integrity. An example of a less extreme failure definition is the loss of functionality. Further, along with different definitions of failure, the properties of a population of components or tubulars can vary widely within the population because of natural variations in strength and geometry. However, the well designer can take the second step to determine capacity by using engineering principles and simplifying assumptions to develop a mathematical formula for capacity. Using the common failure criterion of yield onset, the simplifying assumptions typically include exploiting the symmetry of the round geometry of the tubular or component and addressing only a uniaxial load direction. Other common assumptions include using the minimum yield stress allowed by the material specification and using the minimum geometry (i.e., wall thickness) allowed by the material tolerances. Again, the designer will determine capacity for several operational scenarios.

The third part of the design process is to establish criteria for comparing the anticipated loads with the calculated capacities. The selected tubular or component is acceptable for the well application if its capacities (defined at its failure) exceed the loads by some margin. One example of this comparison is the calculation of an estimated failure probability for the tubular or component using the expected distribution of loads and capacities for a well application and population of tubulars or components. The resulting failure probability is compared to threshold reliability levels. Another example of this comparison is the use of a design factor that is applied to the estimated load or to the calculated capacity (note that the design factor can be split into partial factors with one part applied to the load and another part applied to the capacity). The design factor approach is generally used for well design applications because it is efficient and produces results with proven reliability.

Failure probability targets and design factors are based on past experience with well applications with acceptable reliability. Design factors also depend on the assumed load scenarios and failure capacities, so they may vary widely from designer to designer. The combination of load scenarios, capacities, and design factors (or failure probability targets) represents a well design *system*. Companies that design wells develop internal standards that define required elements of this system for their wells.

7.3.2 System Capacity – Well Integrity

The casing strings form the basis for well integrity. Each string builds on the previous, either isolating it from the internal load (long-string) or extending it (such as a liner). Casing for DW, high pressure wells is larger, higher strength, and may contain flush or semi-flush connections.

The entire system shall be evaluated during well design to ensure a reliable, fit-for-purpose design. Individual company designs can account for different loads and resistance by having varying inspection programs, operational limits, and practices.

7.3.3 Loads, Methodology, and Design Factors

An operator designs a well for a set of load conditions. These conditions are a combination of internal, external, axial, and temperature loads. The actual load cases used in the design are based upon a particular company's philosophy and their experience in the area.

7.3.3.1 Internal Loads – MASP and MAWP Determination

Maximum anticipated surface pressure (MASP) is a design load that represents the maximum pressure that may occur in the well during the construction of the well. As with land and shelf wells, it is a surface pressure.

For DW wells, this internal pressure may be calculated at the wellhead, and it is called maximum anticipated wellhead pressure (MAWP). The MASP can be calculated in several ways, and it can be converted to MAWP. MAWP is MASP plus internal fluid/gas head to the wellhead from the surface. Thus MAWP is the highest pressure predicted to be encountered at the wellhead on a subsea well.

This document only presents examples and leaves actual load-case selection to the operators. For example, MASP calculation methods include but are not limited to, the following:

Table 7.1 Internal Load Cases

Item	Internal Load Case	Description of Load Case
1	Combination of hydrocarbon/mud	Establish the hydrocarbon and mud gradients and their configuration in the well. Use a percentage of mud and percentage of hydrocarbons (these percentages may differ for shallow versus deep strings).
		Use the highest BHP in the openhole section and the gradients of the fluids to surface to determine the BHP-based MASP.
2	Fracture gradient at shoe and hydrocarbons to surface	Establish the hydrocarbon gradient.
		Base MASP on the fracture pressure at the deepest exposed shoe (or shoe with the highest fracture gradient and pressures) less the hydrocarbon head (gradient times true vertical depth) to surface.
3	Hydrocarbons to surface	Base MASP on reservoir bottomhole pressure (BHP) less the hydrocarbon head (gradient times true vertical depth) to surface.
		When used for production loads, the packer fluid's effect on casing burst to the packer with a shallow tubing leak will increase the internal load.
4	Survival Loads	See section 7.3.5
5	Limited kick volume	Based on company design philosophy and regional experience, determine a given kick volume, intensity and hydrocarbon type.
		Perform modeling for circulating the kick out of the well to determine MASP

		and the internal pressure profile. Factors that affect the modeling include: a. Kick models that assume the gas remains in a single bubble give higher values than those observed in the field. b. Kick models that accurately handle a distributed gas bubble are complex, requiring multiphase flow calculations, and are normally not used in shallow well design or for oil reservoirs. c. Gas going into solution in non-aqueous fluid at high pressures also requires a complex model.
6	Completion or treating loads	Base MASP on bottomhole treating pressure less the head of the treating fluid (e.g., fracturing, frac and pack sand-laden fluid). Consider adding an additional pressure margin for bullheading operations. Refer to Section 7.4 for more information.
7	Internal pressure testing	Pressure test casing to verify proper installation, which may, in some cases, simulate service loads.
		Understand that companies select their test pressure based on a combination of regulatory requirements, experience and the designed capacity of the system.

7.3.3.2 External Loads

The pressure gradient that exists in the annulus behind each casing string depends on a variety of factors, and it can vary over the life cycle of the well. Immediately following cementing operations, the gradients are those of the drilling fluid, cement spacers, and liquid cement. However, complex changes can occur as the cement sets and the mud degrades, which is considered in estimating the long-term backup resistance it provides. The external pressure at the stack is based on a saltwater gradient for DW wells.

Because of uncertainty in the annular pressure gradient over extended times, particularly within the cement column, assumptions may be made that represent a conservative case. Some time-dependent assumptions are:

a) The gradient in the drilling fluid above the cement may eventually partially or fully degenerate toward the gradient of the base fluid. This is caused by settling of a percentage, or all, of the weighting solids depending on the particular types of solids used. The time interval for settling to occur depends on well conditions and is difficult to accurately calculate or confirm;

b) For collapse design, consider using the original mud gradient behind the casing (rather than using a partly or fully degenerated mud gradient behind the casing) to avoid under-estimating the driving external collapse pressure;

c) The effective gradient in cement (assuming it is semi-plastic as it sets and is capable of transmitting pressure) in the openhole will equal the pore pressure of the adjacent formation;

d) For cement within a casing by casing annulus (cement in the casing overlap or behind a tieback), less is known about the cement gradient, and it is frequently estimated based on the accumulated history of industry experience. For backup to the burst design pressure, consider assigning cement a gradient equal to its mix-water gradient (pressure is dependent on shrinkage and other elastic system effects).

For the same cement used in collapse design, consider assigning cement the gradient of the unset cement slurry as this provides a more conservative, loading for collapse design. See API RP 65 Part 2 for further details about cementing.

Consider the effect of point loading (such as where uneven stresses are applied through an active fault or collapse of an outer string).

7.3.4 Triaxial

The triaxial yield calculation, provided by API TR 5C3, can be used to calculate initial yielding of the tubular as an alternative to API uniaxial calculations.

7.3.5 Survival Design Considerations

Some load scenarios on tubulars and equipment exceed even the expected operating conditions. Survival design scenarios include extreme cases such as the complete loss of well control (blowout) from a well and the reestablishment of well control by installing a capping BOP stack. The capping stack may be used either to limit the flow from a well by applying backpressure (cap and choke) or to completely shut off the flow (cap and shut in). Note that the cap and choke scenario can be further classified as choke and flow to the environment thus reducing the impact over an unconstrained blowout or as choke and contain to collect the discharged fluids with surface production equipment. However, the well loads for choke and flow or choke and contain remain the same.

Extreme load scenarios are unlikely; however, it is appropriate to consider loads that arise from these scenarios and to determine if the tubulars and equipment can survive the conditions. The well designer may adopt a philosophy using different criteria for failure and different design factors.

Example 1: When designing for regular kick loads, the design criterion might be defined as the onset of yield, using minimum material properties and wall thickness and a design factor greater than 1.0. When determining tubular survival capability under extreme load conditions, the design criterion might be based on tubular rupture capacity in API TR 5C3 using actual material properties and/or operator design practices based on advanced design methods or physical testing. Evaluate the entire system, including liner hangers, connections, and wellheads. Formulas for the onset of yield and for rupture for a non-sour environment are contained in API TR 5C3 or in API RP 1111.

Note: An assumption inherent in putting a load scenario into a “survival” category is that while the tubulars or equipment may survive the load, the normal operability may be compromised by exposure to the survival load. Re-assess the suitability of the well for continuing operations after a survival load situation occurs.

Examples of loads that might arise from survival scenarios for DW wells include:

Example 2 - Collapse loads during uncontrolled flow: low back-pressure at the discharge location (surface or mudline) enables high flow rates and a low internal pressure profile compared with a typical hydrostatic column of drilling or completion fluid. The high flow rates of fluids at the reservoir temperature heat the wellbore, causing the fluids in the annuli to expand. The pressures in the annuli increase because of this expansion, and collapse loads are created. The net external pressure loads and the thermal effects increase compression loads on the casing, which also create uplift loads on the casing hanger.

Example 3 - Burst loads following cap and shut in: drilling casing design always considers that a kick load may occur, and production casing design always considers that the tubing may leak; however, the *maximum expected load is based on normal well control operations. Installing and closing or choking a capping stack after uncontrolled flow may subject the exposed tubulars and equipment in the well to a full column of the production fluid with reservoir pressure at the source. The resulting burst load scenario also includes a high temperature arising from the warm flow when the capping stack valves are initially closed and transitioning to the geothermal temperature when the flow is stopped and the heat dissipates. A combination of internal pressure and cool temperature increases the tension load on tubulars, particularly at the top of the well.*

7.4 Tubing Load Design

7.4.1 Completion Tubing/Work String Load and Design Consideration

All components in the completion should be designed for the anticipated service over the life cycle of the well, (e.g., tubing, drillpipe, connections, packers, polished bore receptacle [PBR], seals, nipples, mandrels, SCSSV, plugs).

Considerations for completion tubing and work string design include:

- Design the production casing in parallel with the completion tubing and work string;
- Verify that the design is fit-for-purpose with design margin;
- Investigate the most highly loaded and weak points throughout the tubing and work strings for burst, collapse, tensile, and compression strength (e.g., below the tubing hanger, at the production packer, and cross-overs throughout the string);
- The subsea completion tubing strings can be fixed to a production packer or have a seal assembly that can be inserted into a PBR above or below the production packer. Consider the change in loads on the production packer movement of the seals in the PBR.

Consider documenting the requirements for completion tubing and work string design, completion tubing procurement, maintenance, and preparation, as well as well installation/workover operations. Ensure documentation meets regulatory requirements.

Consider including the following steps during the design process.

a) Establish possible completion tubing string designs for the well after compiling the key well data and perform a first pass risk assessment;

b) Develop a conceptual completion tubing string design and review with all stake holders.

There are many design issues to consider when evaluating tubing, production casing and work strings for completions.

Verify that the conceptual completion tubing design(s) are able to accommodate anticipated flow performance for the well by using system analysis (i.e., inflow/outflow performance) software. Consider the following items:

- Flow rate is acceptable (i.e., pressure drop in tubing is acceptable);
- Fluid velocities are below erosional velocity (see API RP 14E for information about erosional velocity for carbon steel in a corrosive environment. Ensure tubing metallurgy is selected such that it is sufficient to handle the anticipated erosional and/or corrosion induced environment.);

- Tubing size results in proper flow regime (i.e., tubing small enough to minimize slugging or allow the necessary minimum velocity to unload liquids in a gas well).

A detailed well design (e.g., casing size, casing set points, cement tops, and others) is established that will accommodate the selected completion tubing string and work string concept. The profiles listed below are used to calculate the stresses along the depth of the completion string and associated selected downhole completion equipment:

- Temperature/pressure profiles may be developed along the depth of the completion strings under different well operations (including startup) using software with a rigorous thermal module that will provide the resultant analytical stress along the depth of the completion string. The stresses can be calculated using the following:
  - Temperature effects (axial);
  - Pressure (burst/collapse);
  - Weight (axial);
  - Tubing to packer force.

The computed stresses are compared to the minimum yield point of the selected downhole completion equipments' metallurgy at its associated depth in the well system. When comparing the actual stresses to the selected tubular material, consider the following criteria:

- The standard four-region API formulas for collapse (i.e., based on carbon steel). Collapse capacity in relatively thin-wall tubulars can be governed by geometric instability rather than by hoop stresses that approach yield stress. See API TR 5C3 for approaches to calculating collapse strength. (See API RP 5C5 for more information about geometric instability).
- Burst and tensile loads assume failure will occur due to stresses exceeding the yield strength of the material. The tubing design is based upon uniaxial, biaxial, or triaxial analysis. Triaxial design is the most common design method used for tubing design.

7.4.2 Data Collection

Use the data below that is relevant when developing a completion tubing/work string load evaluation and design:

Reservoir Data:	— Fluid – oil/gas/water composition — Pressure — Volume — Temperature
Interface or Compatibility of Fluids on Metallurgy:	— Formation fluids — Acid formulations — Frac fluids — Brines and completion fluids
Drilling Well Data:	— Mud density — Frac gradient (leakoff test/formation integrity test) — Casing dimensional data

Production and/or Injection Data:	— Field or well life expectancy — Early-, mid-, and late-life flow injection rates — Separator pressure/surface injection pressure
Artificial Lift Requirements:	— Gas lift — Electric submersible pump (ESP)
Well Control Actions:	— Well kill — Separator injection pressure/rate requirements
Intervention Methods and Treatment:	— OD/ID ratios for fishing — Post-completion acid/scale treatments — Surface pressure
Maximum Anticipated Tubing Pressure (at Subsea Wellhead):	— Surface pressure — Hydrocarbon gradient
Undisturbed Temperature Profile	— Temperature profile

7.4.3 Load Cases

Table 7.2 *Completion Tubing String Loads* and 7.3 *Completion Work String Loads* are examples of load cases that may occur in a given well. Section 9 *Completion Operation Considerations* discusses more detailed aspects of completion design to consider when evaluating loads for production casing, tubing string, and work string.

Table 7.2: Completion Tubing String Loads

Item	Load Case	Description of Load Case
1	Initial installation/testing condition	Buoyed weights of string plus set down weights, pressures, or pressure functions for completion string equipment.
2	Production rates – (production/ injection wells)	Early-, mid-, and late-life production rate modeling. Determine production/injection profile that provides the maximum or minimum temperature (APB consideration).
3	Hot shut-in (short term)	Well flowing at maximum internal tubing pressure and temperature and a surface shut-in or a downhole SCSSV closure occurs.
4	Cold shut-in (long term)	Well is in a static condition with maximum internal pressure and geothermal temperature.

Item	**Load Case**	**Description of Load Case**
5	Partially or completely evacuated tubing	Late-life production. Well is in a static condiditon; fluid level lower in tubing due to reservoir depletion (i.e., oil wells). Pressure reduction due to perforation plugging (i.e., gas wells).
6	Evacuated tubing by casing annulus	Well is flowing at maximum internal tubing pressure and temperature. “A” annulus loses hydrostatic head resulting in a lowered pressure condition to a known point in the “A” annulus (Collapse loading on production casing [with APB consideration]).
7	Hot kill – no tubing leak	Well is static with maximum pressure and temperature conditions in tubing string and “A” annulus. Injection pressure is greater than maximum shut-in tubing head pressure.
8	Cold kill – no tubing leak	Well is static with maximum pressure and geothermal temperature conditions in tubing string and minimum pressure at geothermal temperature in the “A” annulus. Injection pressure is greater than maximum shut-in tubing pressure.
9	Tubing leak hot shut-in	Well is shut-in with maximum internal tubing pressure and temperature. Tubing leak is located below the tubing hanger.
10	Hot kill with tubing leak	Well is static with maximum pressure and temperature conditions in tubing string and “A” annulus. Injection pressure is greater than maximum shut-in tubing head pressure. Tubing leak is located below the tubing hanger.
11	Matrix injection (acid/scale treatment)	Well is static with maximum pressure and minimum temperature conditions in tubing string and in the “A” annulus. Injection pressure is greater than maximum shut-in tubing pressure.
12	Overpull	Applied tension above string weight to provide ability to pull tubing string during workover or installation operation.

Table 7.3: Completion Work String Loads

Item	**Load Case**	**Description of Load Case**
1	Initial/testing condition (hook load)	Buoyed weights of work string plus set down weights, pressure tests, or pressure functions for lower completion equipment
2	Fracture simulation	Maximum expected pumping rate during frac operation
3	Fracture stimulation with leak	Work string connection leaks at the mudline during frac pac operation resulting in pressure transmitted to work string by casing annulus
4	Screenout during stimulation	Fracture operating load conditions with plugged perforations with no loss of pressure in work string; bottom of work string is exposed to full pump pressure and frac fluid hydrostatic pressure
5	Perforating through casing	Applied internal pressure to work string to trigger perforating gun firing head
6	Overpull	Applied tension above string weight to provide ability to pull work string during workover or installation operations

8 Special Considerations for Drilling

8.1 Wellheads

8.1.1 Basis for Rating Equipment Capacity

Subsea wellhead equipment is addressed by API SPEC 17D and provides requirements for performance, design, materials, testing, inspecting, welding, marking, handling, storing, and shipping. The original equipment manufacturer is consulted for specific equipment-rated design capacities and operating conditions.

8.1.2 Anti-Rotation Devices

Torsional loads may be transferred through the marine drilling riser to the subsea wellhead and conductor/surface casing connections during dynamically positioned rigs heading changes, especially when the slip ring malfunctions. It is recommended that subsea wellheads exposed to torsional loads include an anti-rotation feature. Consider using anti-rotation features for connectors used on all casing/conductor/structural strings welded to the HPWH or LPH. Consider performing a riser turn test upon landing the BOP stack.

8.1.3 Bending and Fatigue Loads

In the planning stages, consider the rig type and applied loads during the well construction, intended life cycle use of the well, and environmental conditions. These dictate the wellhead selection and well foundation design criteria necessary to meet the expected well's life cycle loading. Consider wellhead loading conditions during riser connected drilling and non-drilling operations and loss of stationkeeping (drift-off and drive-off). Installation of the containment stack (increasing the overall height and weight of BOPs) will increase the wellhead loads. Wells in harsh metocean conditions or wells that are intended to be operated with marine drilling riser installed for extended periods of time, such as those wells tied back to a TLP or spar, have the potential for damage or failure from long-term fatigue loading. Wells with the potential for long-term fatigue loading require a fatigue analysis. Considerations for fatigue-resistant wellhead design may include the following:

- Pre-loading the high-pressure/low-pressure housing interface;
- Special placement of the first connection (below point of fixity);
- Connections with optimized stress concentrations factors, (this is the ratio of the localized stress to the stress in adjacent material). This is also known as a stress amplification factor.
- An enhanced subsea production tree connector;
- Special care in the quality of welds and materials selected;
- Special attention to materials selected.

8.2 Casing Hanger/Seal Assembly Lockdown to Subsea Wellhead Systems

The casing strings in DW wells can be exposed to thermal and pressure conditions during the construction and operation of a well, which can cause subsea casing hangers/seal assemblies to lift off the landing seat. Movement in the subsea casing hanger/seal assembly can be detrimental to the ability of the seal assembly to hold pressure.

To minimize or prevent movement of the seal assembly, the subsea casing hanger shall be locked to the wellhead. To accomplish this, the casing hanger seal assembly components of subsea wellhead shall include a feature to lock the casing hanger/seal assembly into the wellhead housing, thus preventing upward movement in the casing hanger/seal assembly.

Consider performing an analysis of the forces on the casing hanger caused by thermal growth of the casing and the pressure differential loads across the seal assembly such as:

- Assessing the potential for casing hanger/seal assembly movement;
- Determining the lock down force necessary to keep the casing hanger in place.
- Verify the rating of the lock-down component is greater than the predicted necessary lock-down force.

Consider the installation of supplemental lockdown subs or bushings above the casing hanger/seal assembly for cases where the upward loading conditions of the casing string anticipated from the thermal and annulus pressure effects are expected to exceed the rating of the seal assembly lockring and is needed for long-term production service with its repeated thermal cycles. For some manufacturers, these lockdown subs or bushings may provide greater lockdown capacity than that available from lockdown features integral to a seal assembly. However, the lockdown capacity of the integral seal assembly, lockdown and a supplemental casing hanger lockdown bushing may not be additive. In this case, the lockdown capacity of a single device provides the locking capacity for the well.

Any casing hanger landed in the high pressure wellhead (HPWH) shall be locked down to the wellhead when installed or as the immediate next step. An exception is a tieback hanger landed in the HPWH (where the openhole is isolated by a liner hanger with packer or a cemented tested liner lap and cemented (or otherwise secured, such as with a swellable packer) annulus of the tieback string). In this case, the hanger shall be locked down, but not necessarily as the immediate next step.

Additionally, the casing hanger seal assembly shall be verified as having been installed and sufficiently pressure tested to indicate proper installation.

8.2.1 Casing Hanger Seal Assembly Verification

Casing hanger seal assemblies are designed to provide bidirectional sealing capability. An installed seal assembly can only be tested to maximum pressure from above. The assurance of the seal effectiveness from below is based on design and validation testing for the equipment, quality assurance (QA), and correct installation and pressure testing from above. Consequently, a wellhead seal assembly can be considered a verified barrier.

Casing hanger seal assembly designs are qualification tested following the requirements established in API Spec 17D. This includes testing at the rated pressure and temperature extremes in addition to functional load testing of the casing hanger/seal assembly lockdown.

The seal in the hanger is a barrier in the annulus flow path, and its proper landing shall be verified. Manufacturers may provide lead impression blocks or shear pins on the running tool to verify that the seal assembly was installed and positioned properly relative to the hanger.

8.2.2 Corrosion Prevention of Wellhead

Corrosion may occur over the life cycle of a well; (whether a short duration exploration well, or a multi-year production well /injection well). Corrosion protection is provided in these areas:

- Subsea wellhead inner and outer surfaces are protected by corrosion preventative fluids/coatings such as zinc or manganese phosphate or a fluoropolymer; inner surfaces may also be protected by corrosion preventative fluids and inhibited drilling/completion fluids;
- Wellhead seal preparations (ring gasket area) are overlaid with Inconel®[1] Alloy 625 for corrosion protection. Consideration should be given to overlaying other seal areas of the wellhead.

Consider the expected corrosive conditions over the life cycle of the well and how they affect external surfaces. Subsea wellhead surfaces can be protected by coating or cathodic protection. Consider the effect if temporary or permanent guide bases are installed and the well is intended for production service. Corrosion effects can be mitigated through qualities of the paint applied to the conductor or guide bases and/or the number and type of anodes that can be installed on the wellhead or guide bases. If anodes are installed on the guide bases, to protect the wellhead and guidebase, provide an electrical connection between the guide base and low pressure housing/structural casing. For further long term protection of a wellhead, consider attaching an anode “sled” to the wellhead to supplement initial corrosion protection methods.

8.2.3 Subsea Wellhead Ring Gasket

A ring gasket provides the seal between the subsea wellhead and BOP connector or subsea production tree connector. Some wellhead designs include a secondary independent sealing surface in case the primary sealing surface is damaged. Special ring gaskets are available to seal on the secondary sealing surface. Ring gaskets that provide a metal-to-metal seal are recommended for normal service. The normal requirement is for the gasket to seal against internal pressure. However, under specific conditions, sealing against external pressure can be required of the gasket such as during inflow testing or during production operations. Consider the effect of external versus internal pressure on the gasket to ensure that a proper gasket type is specified or other contingencies are planned.

For long-term production service, review the material composition of the ring gasket and inlay on the wellhead and wellhead connector to avoid galvanic corrosion issues.

8.2.4 Wellhead Growth

Wellhead growth is the term used for axial movement of the wellhead relative to its initial position at the mudline. Wellhead growth is caused by the forces exerted on the wellhead by:

a) Thermal expansion of tubulars tied back to the wellhead;
b) Increasing pressure within the annuli created between the tubulars.

The changes in tubular forces and pressure increases can be caused by thermal effects of increased temperature during production or drilling deeper. Water or gas injection may decrease temperatures.

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[1] Registered trademark of Special Metals Corporation. This term is used as an example only and does not constitute an endorsement of this product by API.

Changes in temperature from initial installed conditions will cause thermal stresses in the well casing. The casing is constrained axially at the top of cement and at the wellhead. The casing strings tied back to the wellhead are constrained axially at the top of cement and also at the wellhead. The temperature increase from production or additional drilling will elongate the steel casing and attempt to make the HPWH move axially upward relative to the LPWH. If the HPWH is locked to the LPWH, this axial constraint will cause a compressive force to be generated within the casing.

Increased wellbore temperatures during production or drilling also causes the expansion of fluids in the annuli between well tubulars. If these annuli are trapped, the annulus volume remains nearly constant and the fluid expansion is expressed as a pressure increase. The pressure increase is isotropic and acts on the underside of the casing hangers, as well as on the tubulars. The effect of the compressive stresses in individual tubulars and pressures in the annuli exerts an upward force on the wellhead. If the surface casing (attached to the high pressure wellhead housing [HPWHH]) is not cemented all the way to the mudline, then the HPWHH can move, relative to the LPH (if not latched together), rising above its initial position at the mudline. The axial forces that can act on the locking mechanism between the LPWH and HPWH need to be considered when choosing the rating of the locking mechanism.

The amount of axial movement is calculated as the amount that balances all forces on the wellhead and strains in the uncemented parts of the casing strings. The constraint that enables a solution to the calculation is that all tubular strings have the same displacement at the wellhead because the hangers remain in the same location relative to each other (or there may be significant forces acting on the lock down mechanism for the hangers).

8.2.4.1 Key Inputs

Examples of the key inputs used to predict wellhead growth are the cement tops for the casing strings (defines the amount of strain possible in each string), applied tension, and the production temperature condition (defines the temperature change from the initial conditions that causes thermal stresses and annulus fluid expansion).

8.2.4.2 Effects

If wellhead growth occurs, it can affect the flow line or other subsea equipment resting on the seafloor, but not attached to the well. Conversely, wellhead subsidence can be an issue to decrease tension on subsea hangers.

8.3 Structural (Conductor) Casing

Structural casing, normally in conjunction with the next fully cemented string, provides the foundation for a DW well and is designed and installed with the necessary structural capacity to withstand the expected loads. Two primary loads on structural pipe are axial or bearing load and bending loads.

8.3.1 Axial Loads

Installation methods impact the axial capacity of a structural pipe. In DW well construction, the most common method of installing structural pipe is jetting due to the soft sediments generally encountered near the mudline. If hard sediments or boulders are present then structural casing is installed by drilling and then grouting, similar to a conventional casing string. In more rare cases, the structural casing is installed by driving using a subsea hammer, similar to platform installations in shallow water. The method of installation methods impacts the initial and time-dependent development of axial capacity of the structural pipe. Jetting has the greatest degradation in axial capacity and, if the structural pipe is not designed and installed properly, there is potential to settle and fail under axial load.

The jetted structural pipe must initially support its own weight. If it is installed via drilling and grouting, a temporary guide base or mud mat may be used to support the weight of the string. Later, it also supports the buoyed weight of the next casing string that is landed in the low pressure wellhead housing to avoid wait-on-cement time.

After the first riserless casing string is cemented to the mudline and the cement has set, the axial load for the remainder of the well including all casings and the BOP stack is supported by the combined capacity of these two casing strings. The load that a given string may carry depends not only on its axial resistance, but also the degree to which that load is transferred to the surrounding formations. This may depend on the installation method used and how well it is executed. Axial capacity is dependent on soil strength and the disturbance done to the soil as the structural casing is jetted into place. The amount of disturbance depends on the rate of jetting (pumping), connector ODs and the time allowed for the soil to recover from the jetting operation. Externally flush connectors can improve skin friction development due to fewer disturbances. Refer to API RP 2A – working stress design for the methodology of axial capacity of piles.

8.3.2 Marine-Riser-Induced Bending Loads

The structural pipe withstands the expected bending moments imposed during the well construction and life cycle. The most severe bending loads occur during well construction and result from those loads imposed by the rig and marine riser system. Bending loads applied by the marine riser are a function of the height of the LMRP flex joint above the mudline, riser tension, and maximum angle of the flex joint. A marine riser and structural pipe analysis considers the metocean conditions, vessel offsets, marine drilling riser system, BOP stack, LMRP, mud-weight, and tensions to design the structural pipe. The structural pipe considerations are:

- The bending moment and shear force increase below the mudline and reach a maximum between 5 to 30 pipe diameters below the mudline, depending on soil strengths. The bending moment and shear force decrease below the maximum point and reduce to zero at depth. Consider the effect for the distance HPWH is above the mudline;
- Wellheads, structural pipe, conductor, pipe body, and connection capacities are designed to accommodate bending moments and shear forces;
- Wellhead and structural pipe deflection when drilling riser is removed;
- Additional bending load that may need to be considered now is the addition of a 'capping stack'. This weight, in addition to a tree and BOPs will likely be the worst possible free standing load;
- The maximum mud-weight expected in the well as it will affect the riser tension;
- The type of rig positioning system, DP or moored, and water depth as it will affect the maximum angle of the flex joint;
- The distance the HPWH is placed above the mudline as it affects the height of the flex joint;
- Deep currents near the mudline can increase bending moment loads;
- Soil strength effects on wellhead deflection and bending moment loads;
- Trawler snag loads need to be considered for bending calculations (depending on area and depth of water).

Note: A worst case scenario is a loss of station and failure to disconnect the LMRP (Drive off without disconnect). Consider performing a riser failure analysis to confirm that a loss of pressure integrity below the BOP stack will not occur in this situation.

8.3.3 Subsea Tree and Flow Line Induced Bending Loads

During completion execution, either a tubing spool or a tree may be attached to the subsea wellhead. This increases the height from the mudline to the flex joint on the BOP stack. The increase in height increases bending loads as compared to a drilling-only case.

Additionally, consider loads applied when pulling in a pipeline/flowline. This exerts a horizontal load that can create significant bending moments. The deflection of the wellhead due to BOP load may need to be considered for the wellhead stiffness or flowline flexibility.

8.4 Mudline Hangers

8.4.1 Open Water Mudline Hangers

Open water conductor strings may be installed and serve the following purposes:

- Isolation of shallow hazards;
- Additional support for structural casing when in soft soil conditions or very heavy surface casing loads are expected.

The mudline hanger has several variations with the seal-when-landed type being the most common. Mud circulation, after the hanger is landed for this configuration, is accomplished by opening and closing ball valves below the hanger with the ROV. Therefore the hanger profile is placed in the 36 in. above the mudline to allow for ball valve access.

8.4.2 Hangers Run Through the 18¾-in. BOP

Shallow liners are a special design consideration for DW wells. The common use of 18¾-in. BOP equipment and the corresponding HPWH, which is designed to incorporate three hangers, can present casing design challenges. This housing is installed on surface casing and its minimum ID sets the maximum diameter for subsequent strings. Well Depth, subsurface geology, and hazards are the primary drivers for well design which will dictate the total number of casing strings required during well construction. Additionally, the potential for narrow margins between pore pressure and fracture gradient often require installation of additional casing strings and can ultimately prevent reaching TD with the desired hole size in deep water. Installation of additional short shallow-casing strings helps to retain hole size thus allowing a DW well to reach its deep objectives when geologic conditions are difficult.

Short, shallow casings that are run as liners are landed in sub-mudline hanger profiles (18-in. and/or 16-in. casing) profiles to preserve the hanger profiles in the wellhead housing for the critical intermediate and production casing strings. These profiles are installed in the surface casing string when it is run. This configuration means that surface casing between the high pressure housing and the sub-mudline hanger profiles can be exposed to higher loads than those for surface casing installed in land or platform wells.

The shallow liner is designed like any other casing string in a DW well. However, the hanger is landed submudline, which adds complexity. The pipe between the HPWH and the submudline hanger is typically dual-submerged arc welded pipe and which is normally built to line pipe specifications and welded into place. Large OD connectors may be welded to the pipe, requiring welding procedures, weld qualifications, and weld testing for applications approaching yield strength. For the section of pipe between the hanger and HPWH, consider fatigue loads at the top of the pipe from BOP stack movement and while running this casing open water.

A quality control system ensures that the components are manufactured from materials having the mechanical and chemical properties and dimensional specifications required for the design.

8.5 Subsidence/Compaction

When reservoirs are depleted, there is a risk of downhole compaction and subsidence at the mudline. This downhole compaction can place considerable strains on the wellbore tubulars. Reservoir compaction due to depletion is effected by porosity, pressure drawdown, formation compressibility, and reservoir geometry. Consider designing wellbore tubulars to mitigate the expected subsidence/compaction loads during the well's service life cycle.

8.6 Salt Loading

Salt may create some of the most challenging casing collapse load conditions. Salt composition varies greatly. The types of salts include:

- Calcium rich salts – Calcite, Dolomite, Magnesite;
- Sulphates – Gypsum and Anhydrite;
- Sodium – Halite;
- Potassium – Sylvite and Carnalite.

There are three types of salt loading. They are:

a) Uniform loading – failure by direct uniform pressure because, over time, the magnitude of the load will equal the overburden pressure at that depth;

b) Non-Uniform loading – loading over a limited contact area when hole quality is poor (causing significant ovality), which is the most severe case because casing collapse resistance reduces rapidly with increased ovality;

c) Shear failure – occurs at the salt/formation interface caused by lateral movement of the salt relative to the formation. This could happen in a deep, hot salt section overlying a compacting reservoir, but in general, the chances of this occurring are small.

Salt creeps with time. Initial indications are stuck pipe and borehole constrictions during drilling operations. Casing collapse over the life cycle of the well is influenced by casing resistance (pipe geometry and cement), non-uniform loading, and salt movement.

The rate at which salt moves depends on:

- Burial depth;
- Formation temperature;
- Mineralogical composition;
- Water content;
- Presence of impurities (i.e., clay);
- Differential stresses applied to the salt.

Chloride and sulphate salts containing water are the most mobile. Halite is rather slow moving. Anhydrite is essentially immobile. Problem salts are those that have high creep rates, those with high moisture content, have a proportion of clay impurities, or are inter-bedded with shale.

Consider the possibility of production-induced heating of salt which can be an issue for subsea template developments with closely spaced production wells. This is especially true if the salt is near the producing interval.

Increasing the temperature accelerates salt movement (e.g., becomes more plastic). This decreases the time needed for the salt to contact the casing.

The considerations for mitigating salt problems are:

- The wellbore geometry: as smooth as possible and in gauge;
- The well trajectory through the salt: minimize doglegs;
- The mud density through the salt: as high as the salt and fracture pressure gradient will allow;
- Under-reaming unstable salt sections: to ensure clearance between the casing and salt;
- Cement system: properly designed for salt environments with adequate slurry properties to achieved compressive strength as quickly after placement as possible, and centralized to provide a continuous protective sheath;
- Lap strings in salt as soon as possible with an inner string that is either partially or fully cemented through the salt section;
- Using a low D/t ratio casing configuration through salt is recommended to resist salt collapse loading.

In summary, depending on the pressure, temperature, and mineralogy, salt may creep with time or it may remain stable. If there is no offset experience the conservative assumption is usually made that it will creep and eventually place a high collapse load on the casing.

8.7 Shallow Hazards Considerations

In many DW environments, shallow sediments were rapidly deposited and did not have time to bleedoff excess pressure and reach a normal hydrostatic gradient. This resulted in shallow sediments becoming pressured above a seawater gradient. When this occurs in shallow unconsolidated sediments, it can cause water and sediment flows if the formation is allowed to become underbalanced. This can:

a) Create instability of the structural or conductor pipe;

b) Prevent casing strings from reaching bottom;

c) Prevent successfully cementing a casing string;

d) Create subsequent buckling and casing wear, and lead to loss of a well or multiple wells in a template.

A limited areal extent site survey, that includes shallow seismic, is normally used to evaluate the depth interval down to the surface casing setting depth to confirm the absence of hydrocarbon accumulations at the planned location and to map the areal extent of any potential shallow water flow zones. When selecting the well location, the planning team assesses the shallow hazards risk. This includes shallow water flow, in-situ gas hydrates, shallow gas, or other potential hazards. If possible, drilling in sites with potential shallow water flow (SWF) zones will be avoided. If a SWF zone cannot be avoided, the recommended industry practice is to drill the interval overbalanced while pumping mud and taking returns to the mudline to prevent the sand from flowing or formation from failing (packoff). Pressure while drilling tools are often used while drilling to aid in kick detection or packoff detection.

In areas with severe SWF zones, an additional conductor casing string is often run and cemented above the SWF zone. This may reduce potential loads, such as subsidence, broaching, and severe washout, which enhances cement integrity on the conductor casing to which the HPWHH is attached. Another potential issue is the sediment buildup at the mudline, which can rise to a height greater than the wellhead and make it difficult to see the well or land the BOP stack in extreme cases.

Zonal isolation requires cement designed to prevent flow while the cement is setting. Zonal isolation is required to prevent sediment production on the annulus of the first cemented string which can cause severe buckling not only on the well, but also on nearby wells.

Reference APE IADC 52780 for more information on the impact of shallow flow on nearby wells. API RP 65 provides additional information on cementing SWF zones in DW wells.

8.8 Hydrates

Hydrates can be encountered in-situ in shallow formations, as well as from well control incidents in DW wells. Shallow sediments in DW often have a lower bottomhole static temperature (BHST) and higher pore pressure at a given depth than a similar depth in shallow water. This can allow hydrates to form in porous formations. After drilling the zone, the hydrate in the pore volume of the cuttings will be released. Additionally, if the bottomhole circulating temperature (BHCT) is high enough, it can continue to disassociate the hydrate formation and release additional gas. Figure 8.1 describes hydrate formation in 1200 meters of water.

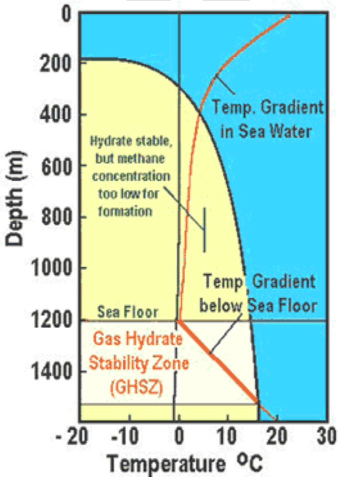


Figure 8.1: Example of Hydrate Formation

A given volume of hydrates releases a significant amount of gas when it disassociates. A cubic foot of hydrate can contain as much as 170 standard cubic feet of gas. When in-situ hydrates are detected on seismic, it may be possible to position surface locations of wells avoid penetrating a hydrate zone. If avoidance is not possible, then consider drilling the hydrates open water to avoid having hydrates in the riser. If hydrates are to be drilled with the riser in place, consider the hydrates affect on mud type, solids control, and cementing.

During well control events, gas can be trapped beneath closed BOPs or closed C/K valves. Near the mudline, the combination of cool temperatures and pressurized gas can cause the formation of hydrates, which can plug the C/K lines as well as the wellbore and prevent circulation. This problem normally does not occur in NAF because the water is emulsified in the oil phase and the water phase has a high salinity.

Documented incidences of hydrates forming during well control events have occurred in water-based muds (WBM). When using WBM, consider using a high salinity and/or glycol mud to inhibit the formation of hydrates. If WBM is used, or the upper portion of the well is displaced to seawater, consider spotting a high salinity glycol pill in the wellbore and across the BOP stack to inhibit the formation of hydrates during extended periods of non-circulation.

Hydrate formation should also be considered during completion operations. Completion operations are typically exposed to the formation and are often executed for long periods of time under static conditions. Static conditions present the potential for gas migration and allow the completion fluids to be cooled significantly. Completion fluids should be selected that are hydrate-inhibitive.

Hydrates can also collect below the connector and prevent release of the BOP stack. Mitigations may include hydrate diverters or connector ports to inject methanol. In areas of known hydrates, assess this risk.

8.9 Liner Hangers

Liner hangers provide the ability to hang the weight of a liner in the casing in which they are set. When equipped with an external packer element, they also provide a barrier to annular flow. The packer element isolates the annulus above from that below load cases for drilling liners essentially form a subset of load cases for intermediate/ long-string/ drilling casing. Despite the reduced footage, a deeper 'casing top' results in several key differences in design and installation which dictate a high level of diligence in well design. Worst-case discharge collapse loads may be very high at the bottom of the well. With respect to production liners, systems can be categorized as follows: (A) production liners hung off inside production casings and (B) production liners hung off inside drilling casings (liner to be tied back by production tieback casing). With respect to system (A), liner hanger integrity is determined foremost by the presence of cement in the liner lap if sufficient strength cannot be generated due to slim hole requirements. If there is no cement in the lap, then the system integrity is determined by the elastomer seal integrity, the capacity of the slips and holddown mechanism and the capacity of the various machined components/cylinders. These should be carefully considered by the well designer. With respect to system (B), seal integrity and redundancy is critical. Reliability of the system can be greatly enhanced if elastomer seals of the hanger can be isolated by stabbing the casing tieback string into a PBR below the liner hanger with a seal stem that includes multiple redundant seal stacks, including perhaps metal bump seals for some applications. Cementing will help prevent the seals from moving due to pressure or thermal loads. Production liners must have the long-term reliability to contain and control the produced fluids over the life cycle of the well. This requires that the string is adequately rated of a full shut-in load on a full column of reservoir fluid as well as collapse loads with APB. Production liners may also require different metallurgy appropriate for the produced fluid. Examples of liner hanger considerations include:

- Material selection for liner hanger equipment is similar to that used for the tubulars above and below the liner hanger system;
- In sour service applications, reference NACE® MR0175 for H_2S service;
- CRA materials may be considered if the liner hanger system is in the wetted flow path for water injection or CO_2 service;
- Design for liner hangers for expected pressures and combined loads;
- The burst and collapse rating of the packer body relative to the ratings of the liner and outer casing compared to design requirements;
    - In close tolerance liner hanger configurations (e.g., 13⅝ in. X 11⅞ in. and 11⅞ in. X 9⅜ in.), it is difficult to design for full burst and collapse ratings if high strength tubulars are used;

    - To increase the system reliability in these applications, consider positioning the PBR below the hanger body to isolate the hanger body when tying back the casing. Setting the hanger in the next larger string can also allow “room” to design the PBR with higher burst and collapse capability than in close tolerance applications.
- Collapse loads (including APB) on tieback sleeves and PRBs when tied back.

The packer sealing elements on liner hangers (and LTPs) are considered reliable if used within their design limits, service conditions, and installed successfully. If casing wear is expected in the outer string, consider running a caliper or casing evaluation log to help select the hanger setting depth. Avoid setting the hanger in worn casing or doglegs.

Some liner hangers (hydraulic) have internal ports and pistons with sealing areas that are used to set the hanger. These ports and seals may experience long-term exposure to wellbore fluids if they aren’t isolated. This reduces the reliability of the hanger packer as a barrier because it provides another pressure containment failure path. The reliability of a hanger packer as a barrier can be increased by eliminating the internal ports and sealing areas as a possible leak path. This is accomplished by using a liner/tieback combination that positions a tieback PBR below the hanger or one without internal ports (mechanical set or expandable).

The pressure and tensile load ratings of hanger system may be limited by the slip design. In many cases, the pressure that can be applied to the top element of a liner hanger packer is limited by the slip loading capacity. Slip capacity ratings are related to the weight and grade of the outer casing along with the status of backup in the outer annuli. Cemented casing provides some backup to slip loading, thus increasing the total load capacity.

Intermediate casing/liners must be isolated with a tieback string if subsequent shut-in loads could exceed the intermediate string’s rating (reservoir fluid in the intermediate string).

8.9.1 Expandable Liner Hangers

Expandable hangers are built from a solid hanger body and may have bonded elastomeric elements on the outside. These types of hangers are expanded after they are run in place. The expanded hanger body and bonded elastomeric elements provide a bi-directional annular seal with multiple redundant seal elements. These seal elements also support the liner weight and tensile/compressive loads on the liner hanger as the result of various life cycle operating conditions.

8.9.2 Seals and Seal Stem

Seals used in the tieback receptacle must have long-term reliability to contain and control the produced fluids over the life cycle of the well. Material is selected based on well conditions and compatibility with well fluids. Seal movement from changing thermal or pressure loads can reduce reliability. Consider cementing the tieback to prevent these movements.

The seal stem and tieback polished bore receptacle (PBR) may have a reduced burst and collapse capacity. Positioning the seal stem in the PBR, so that it fully engages or bottoms out in the PBR, may increase the collapse rating of the PBR/tieback stem system by reducing the exposed length of unsupported PBR. Consider the impact of a telescoping joint, which allows seals to land out, on system reliability.

8.10 Expandable Tubular Goods

Expandable tubular goods (ETG) may be used for well construction, including DW well designs, when conventional well designs are not adequate to maintain objective hole size at TD. ETG are most commonly used as drilling liners, although other applications include cased hole cladding to protect damaged casing and openhole cladding to isolate a troublesome interval. An ETG is run as a tight tolerance liner below a conventional protective casing or liner. When on bottom, the ETG liner is expanded from the interval TD into the last exposed casing or liner to preserve hole size.

ETG material is a thin-wall steel tubular that has reduced burst, collapse, and tensile capacities over conventional casing. As a result, the ETG drilling liner is treated as a “casing shoe extension” to increase effective shoe strength or case off a troublesome interval. Therefore, the load cases evaluated when designing an ETG are reduced to only those functional loads required to run and install the ETG, test ETG and liner shoe integrity, and drill to the next casing/liner point.

While nested ETG have been installed, a single ETG liner is typically installed and then is cased off by a conventional liner or casing as soon as practical to protect the well from the reduced ETG load ratings. In all cases, conventionally designed casing and/or liners above the ETG will provide the final well control barrier as the ETG is considered a shoe extension.

When designing the ETG drilling liner, consider the following loads:

- Running;
- Cementing;
- Expanding;
- Pressure testing;
- Shoe testing;
- Drilling loads.

The collapse rating of ETG liners is low when compared to conventional casing or liners. Therefore, the collapse load case evaluated is the maximum evacuation that can be achieved while maintaining the target collapse design factor. These design limits will be documented and well operations conducted to stay below these design limits. For more information, reference API RP 5-EX *Recommended Practice for Solid Expandable Systems* (in progress).

8.11 Alloys in a Cracking or Corrosive Environment

Consider these conditions in corrosive or cracking environments:

- Cracking environment – be aware there are multiple practices and standards available addressing the qualification of downhole tubular alloys specifically NACE-TM0177, API SPEC 5CT; API SPEC 5CRA; NACE-MR0175. Furthermore, API SPEC 5CT provides criteria for passing both NACE Method-A and NACE Method-D testing to qualify carbon alloy. Always review regulatory requirements for metallurgical properties in cracking or corrosive environment.
- When the reservoir is classified as sour by NACE-MR0175/ISO-15156, the production casing, tubing and accessories (casing/liner hangers, PBRs, seals, etc) refer to NACE for sour service specifications and maximum limits of environmental exposure.

- If intermediate casing is exposed in or across an environment outside the casing, which may cause pitting or wall loss corrosion, consider fully cementing the exposed casing and/or using thicker pipe. CO_2 contributes to corrosiveness of the fluids.
- ISO-TR-10400 provides limit formulas to accurately calculate the tubular du$_{ct}$ile rupture pressure, in excess of the yield pressure, in a non-sour environment. For carbon casing in H_2S, do not consider using the ductile rupture formula cited in ISO-TR-10400 unless the pipe has appropriate fracture toughness in the sour environment as described in Annex D of ISO-TR-10400. Even sour grade casing can fail when loaded just to the yield pressure in a sour environment.
- Internal pitting corrosion may initiate cracks and allowing for pitting corrosion with wall thickness in these environments may be problematic.

8.12 Downhole Threaded Connections

Consider the following for the selection of downhole threaded connections:

- Metal-to-metal seal connections when exposed to hydrocarbon zones, especially for gas zones below surface casing.
- Intermediate casing connection wear while drilling: Flush or semi-flush connections can have less wear tolerance than threaded and coupled connections. Consider wear mitigations (e.g. thread design/metal-to-metal seal placement, modeling, thread compound type).
- Consider API RP 5C5 testing of the intermediate connection for wells with casing connections potentially exposed to hydrocarbons (e.g., during a well control situation).
- Production casing **–** consider a connection that was successfully evaluated to either of the two most severe connection application levels of API RP 5C5. This is particularly important where pressure sealing from the back side is required. Sufficient field experience with appropriate production casing loads and conditions can be a substitute for physical testing. Consider survival type loading when using field experience.
- API RP 5C5 testing to either of the two most severe connection application levels is recommended for all production tubing connections. The combination of field experience and physical testing can be used to demonstrate that a connection design is fit for specific applications.
- The API RP 5C5 laboratory testing provides discriminating qualification of the connection product within its manufacturing and makeup tolerances. Equally important are manufacturing process control, quality assurance process, and a field deployment procedure consistent with the product that was qualified. These processes are essential in assuring that the connection that is manufactured and installed in the well is consistent with the product qualified in laboratory testing. Elements to consider include:
  - Quality system;
  - Quality control and inspection;
  - Consistency between first and last articles manufactured;
  - Thread compound;
  - Field deployment procedures (including torque turn, if applicable);
  - History of successful deployment.

  NOTE: Consult the connection supplier to confirm the application conforms when extrapolating tests across different sizes, weights, and/or grades.

8.13 Casing Landing Strings

DW well designs normally incorporate numerous casings and liners that are run on drillpipe running strings or dedicated landing strings. The design and inspection of the landing strings is critical because the well depths can create extreme casing and liner loads. Failure to properly design and inspect landing strings and hoisting equipment can result in dropped casings and possible loss of well control.

8.13.1 Static and Dynamic Axial Loads

The landing string is used to run all DW casing strings and designed with adequate tensile capacity, including:

- A design factor to support the expected static weight casing and the landing string;
- A margin of over pull plus those dynamic loads associated with acceleration loads while running the casing;
- The acceleration load associated with DW floating rig's response to metocean conditions.

The static casing running load and designed margin of overpull calculations, addressed in API RP 7G Section 7.4, can be calculated manually or by using engineering design software. The dynamic loads associated with the running of casing are calculated by using engineering design software while making assumptions on pipe running speeds and deceleration as the landing string is set in the slips.

Floating vessel motion also impacts dynamic loads on the landing string. These loads are dependent on the vessel response amplitude operators and the sea state. Analyze the casing and landing string for the allowable sea state analyzed to avoid dynamic failure of the landing string. Additionally, consider open-water versus through-marine-drilling-riser deployment in the design.

8.13.2 Slip Crushing

Slip crushing is the deformation of the landing string caused by axial loading of the tube in the slip contact area. Slip crushing occurs when the combined axial loading on the tube and the transverse force caused by the slips begin to yield the pipe ID at the slips. Slip crushing is a complex failure mechanism and the equations describing slip crushing have uncertainty. Therefore, it is recommended that a design factor be applied to ensure that the expected landing string load does not exceed the yield strength of the landing string.

Slip crushing can be especially severe when running casing in DW wells because all casing strings are run and landed with drillpipe. Slip crushing is dependent on many factors including the friction in the slips and bowl, wear between the slips and bowl, geometry, and the design of the slips and bowl. Slip crushing of landing strings may be mitigated through the use of high capacity slips and bowl systems.

Slip crushing enhancement alternatives include the use of dual-shouldered landing strings, (eliminating the need for slips) or using slip crush-proof tube drillpipe. For more information on slip crushing, reference API RP 7G-2/ISO 10407-2 and API RP 7G-1/ISO 10407-1 (a work in progress).

8.13.3 Inspection of Hoisting Equipment and Components

Running heavy casing strings can put high loads, relative to rated capacities, on the entire hoisting system, which includes the landing string, bowl and slips, elevators, bails, block, and top drive system assemblies. Periodically inspect the dedicated landing string, as described in API RP 7G-2 Appendix E, for the expected service conditions to ensure the equipment is fit for purpose. Inspect the other hoisting equipment in accordance with information in API RP 8B.

8.14 Tension Leg Platforms/Spar Considerations

The majority of well operations conducted from DW floating platforms (spars, TLPs) are conducted with a surface BOP stack that is integrated into the marine drilling riser tensioning system. These systems are often platform specific and require a separate load analysis, thus load considerations for these types of well systems are not addressed in this document. However, many of these systems use a drilling riser that is removed after drilling and replaced with a production riser.

During the transition from removal of the drilling riser to the installation of the production riser, the well is exposed to the same temporary abandonment conditions as a well drilled with a subsea BOP stack Consider the downhole loads, barriers, and controls below the surface wellheads.

8.14.1 Collapse

Some completion designs for TLPs and spars use only a production riser and tubing above the mudline. To minimize heat transfer from the producing fluid into the seawater column, the production riser by the tubing annulus is, in some cases, filled with low pressure nitrogen. This creates a collapse load nearly equivalent to full evacuation at the mudline. Consider this load condition during the design of the production casing, any exposed liner tops, and tubing. Refer to API RP 2RD for more information on riser types and design.

8.14.2 Transfer of Axial Loads

Wells completed with dry trees to a spar or TLP, in some designs, try to minimize the weight of tubulars supported by the floating facility. In these cases, the below mudline weight of production casing and tubing is carried by the next outer casing string. The production casing carries the load of the tubing, and the protective casing carries the load of the production casing. The mechanism used to transfer the axial load also imparts a radial load to the outer casing string. In the design of the protective and production casing strings consider the additional axial and radial loads that can be imparted. This may require thicker wall casing to resist radial loads or to carry additional axial loads and higher potential collapse loads.

8.14.3 Fatigue/Bending Loads

Wells completed with dry trees to a spar or TLP usually use a tapered stress joint instead of a flex joint or ball joint at the bottom of the drilling or production riser. The bending moment imparted by the tapered stress joint is different than that normally imparted by a flex joint. TLP/spar designs normally leave the drilling or production riser attached during extreme storm events such as hurricanes. This can create higher static bending loads, as well as impart more cyclic bending loads that can cause fatigue damage. Consider additional loads and load history when designing the subsea wellhead and tubulars connected to the subsea wellhead.

8.15 Annular Pressure Buildup Considerations

8.15.1 Background

Subsea wellheads used to drill in DW do not have access to most outer annuli in the well. Typically, only the tubing by the production casing annulus, known as the "A" annulus, can be monitored and pressure bled down. The pressures occurring in the other annuli cannot be monitored. Consider the well's capacity to withstand the pressure changes during the design of the well. Calculations of potential pressure changes can be considered to determine the severity of the issue and whether mitigation needs to be undertaken. Due to the potential multiple annuli exposed, computerized multi-string analysis is often used to determine the severity of the problem. The casing design should reflect the APB mitigation strategy.

8.15.2 Trapped Annulus Pressure

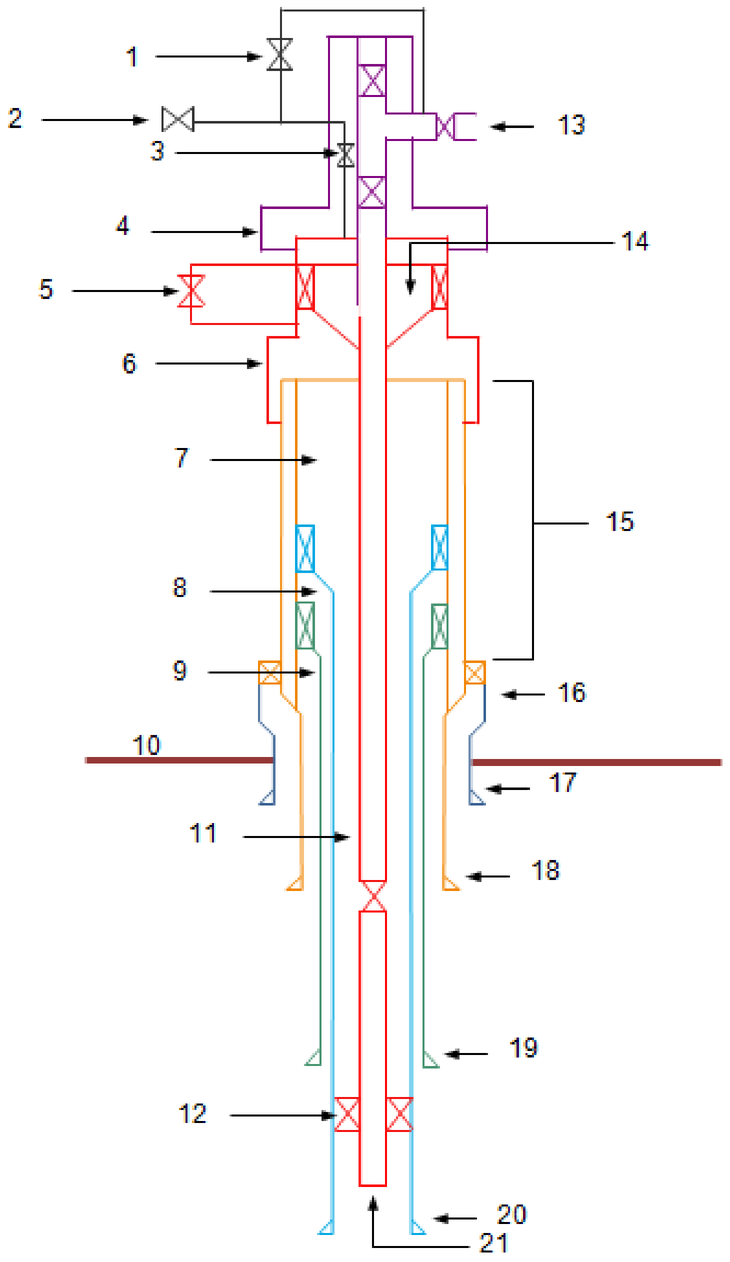
If the annulus is sealed from pressure in the openhole below the deepest shoe, the increased temperature of trapped fluid will cause the fluid or gas to expand. The amount of pressure increase depends on the fluid in the annulus and the change in temperature from initial conditions. This situation is often referred to as trapped annulus pressure or annular pressure buildup (APB).

In addition to trapped casing annuli (shown as the "B" and "C" annuli in Figure 8.2), there are other areas that may contain trapped fluid volumes. Consider the fluid trapped between tubing hanger plugs in a horizontal tree or other similar areas in subsea trees, tubing hangers, and wellhead connectors which may see a large temperature differential between initial installed condition and temperature during production flowing conditions. This temperature increase can cause a significant pressure increase. Considerations should be taken to managing or mitigating this pressure increase.

DW wells can be susceptible to large temperature increases since the initial installed temperature may as low as the mudline temperature, 38-40º F. Many DW well formation temperatures exceed 200º F and can produce at very high flow rates which can bring BHST to near the mudline. Over time, the fluid gradient in an unsealed annulus can change from initial conditions at time of placement for the following reasons:

- Gas migration due to imperfect cement job. This can cause partial or full replacement of mud in the annulus with gas. The maximum resulting pressure would then be limited by either the reservoir pressure less a gas gradient or the fracture gradient at the deepest shoe less a gas gradient.
- Over time, a percentage of solids suspended in annulus fluid may settle. This could cause the annulus fluid to exert a pressure gradient as low as the density of the base fluid.

Figure 8.2 shows a subsea tree with a tubing head and "A" annulus access.



Key

1. annulus crossover valve
2. annulus monitor valve
3. annulus master valve
4. vertical subsea production tree
5. annulus isolation valve
6. tubing tree
7. “A” annulus (tubing to production)
8. “B” annulus (production casing)
9. “C” annulus (interior casing)
10. mudline
11. SCSSV
12. packer
13. production outlet
14. tubing hanger
15. high pressure wellhead
16. low pressure housing
17. conductor pipe
18. surface casing
19. intermediate casing
20. production casing
21. production tubing

Figure 8.2: Subsea Tree with Tubing Head and “A,” “B,” and “C” Annuli

8.15.3 Design Considerations

Annular pressure buildup (APB) can cause both a burst load on the outer casing and a collapse load on the inner casing string. The increased annulus pressure can also cause a piston-effect axial load to be exerted on the hanger. The backup fluid gradient for the burst or collapse case could be as high the original mud or as low as the solids-free fluid.

8.15.4 Mitigations

Some of the potential mitigation options are:

- Avoid a sealed annulus by:
  a) Leaving the top of cement (TOC) a sufficient depth below the previous casing shoe to prevent the annulus from being trapped from the open hole by either cement or settled mud solids. (Refer to regulatory requirements to ensure conformance.)

  b) Using a solids-free fluid, such as a weighted brine, in the cased hole annulus to avoid solids settling and potential plugging.
- Install a compressible fluid in the annulus, which allows fluid expansion without increasing pressure, by:
  a) Adding a compressible fluid, such as nitrogen, so that as the fluid expands and the nitrogen volume contracts, the increase in nitrogen pressure is less than the burst or collapse rating of the casing;

  b) Using compressible liquids (or shrinking fluids); compressibility of these liquids are generally much lower than nitrogen.
- Using crushable material, such as syntactic foam, as another potential solution. A sufficient amount of the material must be run so that it crushes when pressures increases. As the material crushes, the additional volume provides room for the fluid to expand without increasing pressure. However, crushable material does not fully expand after it is crushed; hence, it is a single-cycle solution.
- Using rupture disks in the casing to protect either the outer or inner casing string. Rupture disks can be designed to fail either with an internal or external pressure. They are manufactured to fail at a specific pressure for a given temperature with a very tight tolerance on their design capacity. Rupture disks shall not be exposed to hydrocarbons. A strict quality control (QC) program is essential for manufacturing and installation and deployment of the rupture disks to ensure that the casing, deployed sub, and installed disk or disks provide the specified pressure containment.
- Using insulation methods to limit the transfer of heat from the production flow stream to the casing annuli. Examples include vacuum insulated tubing which limits heat transfer to the annulus and insulating packer fluids which limit heat transfer due to convection in the annulus.

9 Special Considerations for Completions

9.1 Completion Fluids

Solids-free completion fluids are often used in the wellbore to minimize damage to the formation during cased hole completions. In openhole completions, a variety of solids-laden and solids-free fluids are used in the cased hole portion of the wellbore before running any screens that will be placed in the openhole. Check the compatibility of the completion fluid with:

- Various materials of the upper and lower completion equipment;
- Formations exposed in the openhole or from perforations;
- Stimulation fluids.

The density of a brine will vary depending on its temperature and may affect the resulting bottom hole pressure. Depending on the operation being performed, the brine can be heated up through exposure to below mudline temperatures or cooled down due to exposure to the cooling effect of the seawater column.

Completion brines exposed to low temperatures and/or high pressures can crystallize. This situation can occur at the mudline when testing the BOP stack, tubing hanger, subsea production tree, or during a well control event. The designer specifies environmental criteria and required test pressure when choosing a brine. This ensures that the pressurized crystallization temperature for the chosen brine is equal to, or cooler than, the temperature of seawater at the mudline when exposed to pressures equivalent to the hydrostatic pressure of the brine at the mudline plus the maximum test pressure or anticipated shut-in pressure at the mudline. There have been cases where the brine has crystallized when pressure testing a DW BOP stack.

9.2 Materials

Consider differences in material properties of the completion components for tubing mechanics analysis. Different materials may have different properties such as Young's modulus, Poisson's ratio and thermal coefficient, and anisotropy variables.

Also consider potential fluids introduced into the well (and through the well's life cycle) and the interaction between the fluids and selected materials. Corrosion-resistant alloy (CRA) materials may have different properties for the same alloy based upon the process used in manufacturing.

9.2.1 Erosion/Corrosion

Corrosion of tubing ID can occur depending on the tubing material type, compositional properties of the produced fluid, and the chemicals used during its completion and production life. The flow of fluid inside the tubing can erode product surfaces. In some cases, it can continue to expose new surfaces to corrosion, which leads to pitting or even loss of wall thickness. This can also occur in the portion of the production casing exposed to flow during production.

When designing for these issues, the designer considers the full life cycle of the well. Some methods for addressing these issues are to use more CRA or include additional wall thickness to account for potential wall loss depending on metallurgy selection.

9.2.2 External Corrosion

The external tubing surface is exposed to packer fluid and/or lifting gas in the "A" annulus and could be exposed to fluids produced during the producing life cycle of the well. Consider the corrosion rate of the tubing material in the selected packer fluid and/or lifting gas when designing the wall thickness and material type used for the tubing.

9.2.3 Corrosion Resistant Alloy Materials

The proper use of CRA materials is critical in corrosive environments and is addressed in API SPEC 5CRA. However many CRA materials are not addressed by current API specifications. Consider the following:

- Non-isotropic minimum yield strength (MYS) properties (axial, hoop, radial);
- De-ration of MYS with temperature;
- Non-uniform MYS in thick sections (for connection design);
- Tubular wall variability;
- Grade range.

9.2.4 Temperature Cycling

Address temperature cycling effects, between cold and hot temperatures in the design of the tubing and, elastomers. Due to the cool temperatures seen near the mudline in DW, temperature extremes can be more severe than those in shallow water or onshore wells.

The temperature can vary from cold injection temperatures at mudline seawater temperatures to reservoir bottomhole static temperature (BHST) during production. These absolute changes in temperature can affect tubing stresses and movements in varying ways such as compression, tension, and triaxial loads. Consider material ratings when designing for the anticipated temperature ranges.

9.2.5 Liquid/Gas Fluid Effect on Elastomers

In the design, consider these liquid/gas fluid effects on elastomers:

- The effect of different fluids used during the well construction process and producing life (acid, completion brine, produced fluids, and frac fluids, etc.) on elastomer properties and reliability;
- If elastomers are exposed to gases, the gas can migrate into the elastomer. If the pressure of the wellbore is suddenly decreased, the gas can rapidly expand and cause damage to the elastomer. This issue may be more critical for barriers in the subsea production tree than elastomers located deeper in the well.

9.3 Tubing/Work String Connections

Tubing connections are subjected to varying loads over the life cycle of the well. Consider these load cases:

- Life cycle loads such as tension/compression, burst/collapse, and bending loads in the design;

- Cyclic loads that can occur during the life cycle of a well.

Consider the following features when selecting/designing tubing/work string connections:

- Connection sealing type:
    - Metal-to-metal radial seal;
    - Wedge-type;
    - API (LTC, STC);
    - API (LTC or STC) plus elastomer;
    - Alternatives.
- Tubing connection qualification: Consider using either field experience or physical testing to demonstrate that a connection design is fit for a specific application. When physical testing is done, reference API RP 5C5 connection application testing III and IV for all production tubing.

Additional information for the protocol used to qualify the connection or connections is found in API RP 5C5.

9.4 Flow Assurance

Flow assurance is the control or remediation of the deposition/formation of hydrates, wax, asphaltenes, and scale. Many factors affect flow assurance such as fluid composition, pressure, and temperature. Flow assurance is provided either chemically or by thermal management or a combination of the two. Due to the reduction in temperature above the mudline and in the water column, fluids in the wellbore annuli can experience significant heat loss. In long-term shut-in conditions, these areas can cool to the ambient temperature. Consider methods of minimizing heat loss above the mudline when designing the well system.

Some methods of prevention used in industry are:

- Vacuum insulated tubing;
- Gas-filled “A” annulus near/above the mudline;
- Low heat transfer fluid in the annulus;
- Tying back the “A” and “B” annuli from the mudline to a surface structure;
- Injection of fluids to minimize / prevent the effects of hydrates, paraffin, scale etc. through “control lines” strapped to the outside of the tubing,

9.4.1 Vacuum Insulated Tubing

Use vacuum insulated tubing (VIT), which consists of a double tubing wall welded together on either the ID or OD of the joint. The vacuum between the two pipes achieves very low thermal conductivity to reduce heat transfer from the tubing to the surrounding annuli. When using VIT, consider the following issues:

- Proper design of outer (collapse) and inner (burst) tubing. Using burst, collapse, and tensile design for the pipes, welds, and connections composing the string of vacuum tubing. It is important to remember that VIT does not have the typical backup gradient due to the vacuum between outer and inner pipes per design;

- Proper weld design to ensure that the weld maintains vacuum between the two pipes under the applied loads and potential corrosion;
- Qualification testing (mechanical and thermal);
- Determining if the well production fluid potentially is sour, and consider the possible impact that the combination of a sour fluid environment and service loads may have on cracking failure of the welds of internally welded vacuum tubing. In a sour well environment, consider the possibility of using externally welded vacuum tubing and the effectiveness of isolating the tubing annulus from the production environment in cases where potential leak paths are present (e.g., gas-lift mandrels);
- Planning for the significant heat transfer that occurs at the couplings used to connect the vacuum insulated pipe. The thermal conductivity of the coupling can be significantly higher than the vacuum pipes.

9.4.2 Surface Controlled Subsurface Safety Valve

The SCSSV should, if practical, be set below the deepest hydrate formation depth to prevent the formation of hydrates below the valve under long-term shut-in conditions if the temperature cools to the ambient temperature at the valve depth. When set below this depth, and with proper operational hydrate mitigation of the tubing above the SCSSV (i.e. loading the tubing with methanol), hydrates are not likely to form in the tubing. Consult government regulations for setting depth requirements.

The top section of production casing may need to accommodate the large OD SCSSV and control lines. Give additional consideration to these conditions when choosing a setting depth:

- Expected surface and mudline operating pressure;
- Pressure rating of control lines and control line connections at tubing hanger;
- SCSSV operating system type.

9.5 Wellbore Considerations

9.5.1 Wellbore Geometry

Wellpath type (vertical or directional) and casing size relative to tubing size can affect the design of the well. Larger ID production casing and more vertical wellbores make it easier for tubing and work strings to buckle. The effect of wellbore curvature/dogleg severity causes bending stresses on the casing, tubing, and work string. Friction loads also vary based upon the geometry of the wellbore and lubricity of the fluid in the wellbore.

9.5.2 Cement Supported and Unsupported Casing

Setting slip-type tools in casing that is unsupported by cement can lead to casing failures. Additionally, casing unsupported by cement can buckle when subjected to higher internal pressures (either hydrostatic or induced) and temperature changes versus other conditions. Consider the effect of cementing on compaction loading.

9.5.3 Depletion

One load case that should be considered is casing collapse due to low pressure in the wellbore due to depletion. The assumed pressure in the wellbore at well abandonment will result in collapse loads for the production casing and tubing. The type of reservoir being produced and its producing method may affect this value. An oil reservoir that is planned to be artificially lifted may be depleted to a much lower pressure than one being produced under natural depletion. Gas reservoirs can generally be produced to a much lower reservoir pressure than oil reservoirs.

The effect of formation compaction may cause abandonment of the well prior to reaching the predicted minimum abandonment pressure.

9.5.4 Artificial Lift

Artificial lift methods may be used to increase production from DW wells. It may cause increased collapse loads on the tubing, casing, and accessories. These artificial lift methods will affect well design loads:

- Gas Lift

  The depth of gas injection into the production flow stream may change over the life cycle of the well The injection point may start near the mudline and move down the well to near the producing reservoir late in the life cycle of the well. The gas will remain pressurized during normal operating conditions. The gas pressure in the “A” annulus can drop, which can cause the pressure at the lowest gas injection point downhole in the “A” annulus to fall to near-atmospheric pressure. Consider the potential collapse load when designing the production casing and production tubing.

  NOTE: Consider the effect of wet injection gas causing hydrates or corrosion in the annulus.

- ESP

  A method of increasing production from DW wells is to install downhole electric submersible pumps. Hanger and packer penetrations can be a key concern for long-term power cable reliability. System reliability for cable and connections is crucial in DW due to the high cost of intervention. Downhole ESP packers can leak, resulting in a falling fluid level in “A” annulus. This can cause a potential collapse issue for the production casing.

- Seabed Pumping Downstream of the Subsea Production Tree

  Subsea pumping can increase the drawdown on the well. Consider the potential collapse load.

9.5.5 Subsidence/Compaction/Salt Creep

The properties of the formation near the wellbore may change during long-term production. Salt creep may cause point loading or collapse. Depletion may cause compaction in the producing reservoir and subsidence at the seabed. It may also induce fault movement. Formation movement may induce additional loads on the well. This can cause radial, tensile, compressive, point loading, and/or shear forces to the casing and tubing components.

9.5.6 Backup Gradient Allowance for Load Evaluation

Backup gradients can change depending on well operations over time. Consider all backup fluid gradients to properly design the tubing, work string, and completion equipment such as:

- Gas lift backup gradient;
- Completion packer fluid;
- Completion fluid gradient,
- Cement backup gradient (look at drilling section);
- Applied backup pressure during fracturing;
- Operational control of pressure envelope on “A” annulus.

9.5.7 Annular Pressure Buildup

Temperature in the various annuli can change due to production or injection flow over the life cycle of the well. The changes in temperature can affect the pressures in these annuli. These pressures may lead to tubular failure. See Section 8.15 *APB Considerations* for additional information.

9.6 Deepwater Sandface Completion Techniques

Deepwater sandface completion techniques are selected based on the probability of producing solids.

For conditions of little or no sand production, completion techniques may include:

- Openhole completions;
- Casing and perforations;
- Uncemented slotted or pre-drilled liners;
- Cased hole low-perm fracturing (very high pumping pressures).

For conditions where sand production is likely, completion techniques may include:

- Openhole with standalone screens;
- Openhole with expandable screens;
- Openhole gravel packs with screens;
- Cased hole frac packs with screens (high pressure during treatment, screen-out, and reversing);
- Cased hole gravel packs with screens.

9.6.1 Fracturing Considerations

Reservoir fracturing may be used as a technique to increase wellbore productivity by improving near-wellbore productivity. Fracturing creates unique loads due to the high pressures, thermal cooling, and erosion if proppants are used. Consider the following issues:

- Reservoir supercharging

  During fracturing operations, low-perm formations may be slow to bleed off. This effect may lead to charging the reservoir to a pressure higher than initial conditions on a temporary basis. The new (temporary) pressure may exceed the hydrostatic pressure of the completion fluid. This can cause flow from the formation into the wellbore, which may result in well control issues and/or damage to sand control equipment installed in the well.

- Fracturing treating pressures

  The fracture treatment operation may induce additional loads on the well due to creation of a near wellbore fracture. These loads include increased burst loads and increased tensile loads due to cooling. High production casing pressure may occur during reverse-out operation post-screen out.

- Proppant and fluid erosion

  During fracturing operations, high pump rates can be used to create the fracture. The production casing and fracturing service tools can experience minor to extreme erosion, depending on the:

  - concentration of proppant used;
  - proppant type;
  - clearance between casing and base pipe;
  - volume of the frac job.

9.7 Intelligent Wells

An intelligent well is a system to comingle, selectively produce, or inject into multiple zones without rig intervention. This completion technique is used to vary the flow from one formation and flow or shutoff one of several sandface completions. It may reduce the number of wells or rig intervention requirements. Consider the impact of intelligent wells on barriers. Some design considerations for intelligent wells are:

- Complexity;
- Reliability;
- Well architecture:
  - Possibility of larger production casing;
  - Hydraulic fluid systems;
  - Electrical components – power requirements;
  - Control systems – standalone or integrated;
  - Requires additional penetrations for packers and wellhead.

9.8 Fishability of Tubing and Work String Components

The proposed tubing and work string can be determined after achieving the conceptual completion design. Consider the proposed size, weight, and grade of the production casing to accommodate fishability of the completion tubing and work string before final selection of the production casing.

9.9 Injector Well Considerations

Consider the potential for trapped pressure to buildup and collapse tubing in a dedicated injection well. This can occur when the annulus behind the tubing (“A” annulus) is kept filled with fluid and injection is terminated. As the fluid heats up it approaches BHST at depth and the pressure in the annulus can increase if the fluid is not allowed to expand.

Consider performing trapped pressure calculations and using them to reinforce the need to vent the tubing annulus while the shut-in injector is warming toward in-situ temperature. If the injector well will also be placed on production, such as for initial cleanup, then consider making routine APB calculations for production heating (not injection cooling) of the casing annuli.

Additionally, consider the potential for cooling of annulus fluids during injection, especially upon initial startup and startup after a shutdown. High rate injection wells can cause significant cooling which can cause the annulus fluids to contract. Therefore, it is not uncommon for the annulus pressure to drop significantly, even to the extent where 0 psi is seen on the annulus.

For horizontal subsea production trees with two tubing hanger plugs, the annulus access line is exposed to ambient seawater above the top tubing hanger plug. The annulus fluid contraction can create a significant pressure differential across the annulus access valve (AAV). The annulus pressure could go from above ambient sea pressure (creating a positive pressure across the AAV) to significantly below ambient sea pressure (creating a negative pressure across the AAV). Cycling the AAV in this manner could lead to seawater ingress over time.

10 Drilling Operations Considerations

10.1 Riserless Operations

During the initial phase of DW well construction, operations are conducted in open water without a marine drilling riser installed. These operations include installation of the structural casing with the Low Pressure Wellhead (LPWH), any conductor casing required, and the surface casing with the High Pressure Wellhead (HPWH), to which the BOP stack and riser will subsequently be connected. These operations are conducted through the open water column without the protection and restraints of the riser, so all tubulars run are subject to loads resulting from current and other metocean forces. Therefore, consider bending and fatigue loads in tubular and connection selection for all conductor casing, surface casing, and drill string components run through the water column.

In areas with soft, homogeneous near-surface clay, the installation of the structural casing string (including the LPWH) includes drilling or jetting the casing to depth. In areas with firmer clays and/or heterogeneous near-surface soils (e.g., sand or gravel layers), the structural casing is usually run into a pre-drilled hole and cemented in place.

The wellhead should be installed as near to vertical as possible to minimize bending loads induced by the subsea BOP stack, prevent internal wellhead and BOP stack wear as a result of drill string side-loading, and help to ensure operation of equipment such as running tools and connectors. Therefore, monitor the inclination of the LPWH during structural casing installation to verify it is within the required range. This is typically accomplished with slope indicators mounted to the wellhead extension joint. This inclination is routinely monitored for change after the subsea BOP stack and riser are connected to the wellhead.

Riserless operations continue for the drilling of the hole sections and installation of the conductor casing (if required) and the surface casing. In riserless operations, circulated fluids (seawater and mud) along with any associated drill cuttings are not returned to the surface, and therefore discharged at the mudline adjacent to the well location.

Well control during openhole riserless operations is provided by the hydrostatic pressure of the seawater column to the mudline along with the drilling fluid and cuttings column below the mudline. A real-time video monitoring system, provided as either part of the rig package or by an ROV, is a key part of the well control monitoring system during riserless operations. The video system provides a means to quickly detect abnormal situations and assist in determining the correct response by:

- Observing the well and surrounding areas at the mudline during drilling, tripping, and re-entry of the well with tubulars;
- Monitoring returns to mudline during drilling and cementing observing for such things as excess returns, loss of returns, cement returns, flow checks, etc.

Open water operations end upon installation of the subsea BOP stack and marine drilling riser system. Open water activities may also occur following wellbore abandonment and during completion operations. Upon temporary abandoned, a corrosion cap may be installed on the wellhead after the BOP stack is disconnected. If the well is to be completed, a subsea production tree will be installed on the wellhead prior to or during completion activities, thus requiring the BOP stack and riser system to be disconnected.

10.2 Operations with Subsea BOP and Riser Installed

After the subsea BOP stack and marine drilling riser system are run, all subsequent well operations are conducted through the BOP stack and riser, which connect the drilling rig to the subsea wellhead and provides a conduit for circulated fluids. Primary well control for this system is provided by the hydrostatic pressure of the fluid column back to the rig. If the fluid column weight or height is inadequate to prevent an influx of formation fluids, the subsea BOP stack can be closed to stop the flow and, if necessary, to circulate the well to a higher density (kill-weight) fluid to allow normal well operations to continue.

10.2.1 Displacement to Non-Kill-Weight Fluids

During some phases of well construction, particularly for completion or abandonment, it is common to displace the overbalanced well construction fluid (e.g., kill-weight fluid) with a lower density fluid which renders the hydrostatic physical barrier ineffective at providing primary well control. Prior to removing the hydrostatic overbalance, it is important that a replacement physical barrier be installed, typically a mechanical barrier, and that this replacement barrier be verified prior to displacing the kill-weight fluid. As part of the verification process, the remaining physical barriers should be inflow tested to simulate the expected load on them during the displacement from the kill-weight fluid. If testing is not possible, such as with annulus barriers or when a second barrier has been set within the wellbore, their physical placement is to be verified as described in Section 7.2.

Upon securing a satisfactory inflow test, fluid displacement shall be accomplished with appropriate controls in place to ensure detection and isolation of a well kick should a barrier fail. This includes, but is not limited to, accurate monitoring of fluid volumes in and out of the wellbore during displacement to detect an influx, if taken. Consideration should be given to include closing the BOPs on drillpipe and establishing circulation through the drillpipe and the service lines (choke, kill, or boost line). This isolates the riser from an influx, enhancing shutting the well in if there is a loss of barrier integrity. Careful consideration of the barrier reliability, planning, and consequence is necessary if the non-kill-weight fluid displacement is to be made with BOP open.

10.2.1.1 Marine Drilling Riser Displacement

During DW well construction, the subsea BOP stack and marine riser normally remain attached to the subsea wellhead after the surface casing is installed until such time as well construction operations are completed. It is the marine drilling riser system that permits kill-weight fluids to be maintained within the wellbore and through the water column to the rig which allows a hydrostatic pressure overbalance to be maintained thus preventing flow from the well. In addition, it is the subsea BOPs that, when actuated to shut in a well annulus, provide a replacement physical barrier to control a well in the event of loss of the hydrostatic pressure overbalance.

During some upsets (e.g. stationkeeping failure) or planned events during well construction (e.g. hurricane evacuation with LMRP disconnection from lower BOP stack) and at the conclusion of well construction operations (e.g. TA, PA, production), the marine riser and/or subsea BOP stack must be disconnected and removed from the subsea well. The disconnection of the marine drilling riser and/or the removal of the subsea BOP stack significantly alter the well control barrier envelope for the well, and hence the operations must be carefully planned and executed to ensure well control is maintained.

Upset conditions that require the marine drilling riser to be disconnected from the subsea BOP stack (e.g. stationkeeping failure) do not allow time to displace the kill-weight fluid from the riser prior to executing the EDS and is addressed in Section 6.

For planned events during the well construction operations for which removal of the subsea BOP stack and/or the marine drilling riser, the displacement of kill-weight fluid from the marine drilling riser and some portion of the cased wellbore must occur. Displacement of fluid below the marine drilling riser is known as a casing displacement. As the kill-weight fluid is a physical barrier, fluid displacements of kill-weight fluid should be preceded by the installation and verification of a different, substitute physical barrier (e.g. cement plug, bridge plug, storm packer, etc).

Riser margin mud can also be applied within the well below the subsea wellhead as an additional, partial barrier. Riser margin mud is a fluid of increased density over normal kill-weight mud which applies a hydrostatic pressure overbalance deep in the well to offset the loss of head from removal of the riser and mud above the wellhead and its replacement with a column of sea water. It is important to note that riser margin mud has a reduced hydrostatic effect at shallow true vertical depths within the wellbore and no effect at applying an overbalance at the subsea wellhead.

10.2.1.2 Completion Displacements

In addition to marine drilling riser and casing displacements, DW completions generally use two other displacement types that can result in underbalanced fluid columns. These are drilling fluid displacements and packer fluid displacements.

10.2.1.3 Drilling Fluid Displacements for Completions

DW completions are typically accomplished in a brine environment; therefore, displacement of the drilling fluid to completion brine is necessary. This displacement can be “weighted;” that is, it maintains an overbalance to formation fluids throughout the displacement. Other methods result in a potential underbalance to formation pressures. The underbalance introduced may be the result of spacers included in the displacement program or may be the result of an indirect displacement involving an initial displacement of the marine drilling riser and casing to seawater. The method chosen is based on the operator’s specific conditions.

10.2.1.4 Packer Fluid Displacement for Completions

Completion brine is commonly displaced to an underbalanced packer fluid, which may be necessary for casing burst mitigation in the event of a near-surface tubing leak. This operation is performed during installation of the upper completion, typically after landing and testing the tubing hanger. An adjustable choke to hold sufficient back-pressure to maintain overbalance to the formation can be utilized to avoid application of negative differential pressure across the downhole physical barrier (e.g., the gravel pack packer and fluid loss valve capable of holding pressure in the direction of hydrocarbon flow). Verified barriers must be in place on the tubing side (e.g., SCSSV) and on the annular side (e.g., BOP stack, annular valve(s) on the HXT or other) prior to removal of the hydrostatic barrier.

Following a successful inflow test period of the physical barrier, operations continue to finalize the completion installation, including closure of downhole flow paths (such as setting the production packer, closing downhole flow control valves, etc.), thereby securing the underbalanced fluid in place and ensuring isolation of downhole formation pressures. In the absence of a successful inflow test, remedial action is to be implemented to correct for the loss of barrier integrity.

10.2.1.5 Riser and Casing Displacement Procedures

A marine drilling riser and/or casing displacement procedure shall be developed and agreed upon by the operator, the rig contractor, and relevant third-party contractors. This helps ensure that all personnel involved in well operations (including appropriate governmental authorities) understand the procedure and its implications on maintaining well control.

Due to the variety of BOP equipment configurations in use and the physical attributes of the wells (e.g., water depth, well architecture, displacement fluids, and displacement depths) the riser and casing displacement procedure shall be rig specific. Careful consideration and planning including understanding the impact on barriers and well control are necessary prior to displacing the well construction fluids from a well. The planning should include modeling the pressure, volumes, pump rates, flow rates, and pit levels for the fluids to be pumped during the displacement. These predicted parameters can then be used during displacement to identify anomalies that may indicate threats to barrier integrity and well control.

The displacement procedure to non-kill weight fluids should be a function of barrier replacements. For example, in an abandonment operation (refer to 7.2 and Annex A), hydrostatic barrier (kill-weight mud) and the BOP stack are to be removed. Install verified replacement barriers prior to displacement such that at least two physical barriers remain in all flowpaths after BOP stack removal, one of which must be mechanical.

For drilling and completion operations, displacement of the riser and well to a fluid that creates an underbalance in the well may be performed with the BOP stack open if the following conditions are met:

- The well has passed an inflow test that subjected each exposed component to a pressure equal to or lower than the pressure it will be exposed to during or after the displacement is complete.
- Two verified physical barriers (one is mechanical) isolate any hydrocarbon zone that could flow if exposed to the hydrostatic reduction in the well after the displacement. Refer to Annex A for barrier requirements.

Note: An abandonment surface plug is not considered a barrier. Also, conventional float equipment installed in the shoetrack is not considered a barrier; the cement in that shoe track, however, may be considered a single, physical barrier.

Consider the following items when developing the displacement procedure:

- When planning the displacement, verify that the barriers meet the minimum standard set forth in section 7.2.
- Confirm that only shearable components are across the BSR (i.e., avoiding tool joints or other heavy wall tools) upon space-out of tubulars prior to and during for an inflow test and/or displacement.
- Verify that physical barriers meet the minimum acceptance criteria (e.g. positive pressure and inflow tests) prior to beginning riser and or casing displacement. If it is not possible to test an individual barrier, as in the case of a second barrier, its physical placement may be verified by a variety of means.
- It is generally insufficient to displace the riser through just the boost, choke and kill lines as the point of disconnect is below these lines and drilling fluid will remain between the circulation point and the disconnect point. Therefore, drillpipe is generally used as an additional conduit.
- Maintain an appropriate method for determining fluid volumes in and out of the wellbore to allow early detection of an influx (if taken) during displacement. Designate the appropriate indicators, verify indicators are monitored, maintain, and utilized
    a. A transfer plan must be in place to displace fluid off the rig and onto other vessels concurrent with the displacement.
    b. Direct displacement from the wellbore to the boat tanks with no other measurements does not allow for accurate monitoring of fluids.
    c. Note that because most displacements are not closed loop systems (as in drilling operations) pit volume measurements may be less accurate than those associated with drilling operations, thus requiring the additional planning.

10.2.1.6 Considerations for Inflow Testing of Barriers Prior to Displacement

Inflow tests are an integral part of demonstrating the integrity of the barrier system prior to the displacing to underbalanced fluids. The inflow test of physical barriers should be of sufficient magnitude to simulate the well construction loads anticipated (e.g. underbalance during riser or casing displacements, packer fluids, etc.). The inflow test may use the work string or the C/K lines to establish the underbalance desired. This is accomplished by displacing the choke, kill, or work string with the underbalanced fluid resulting in the desired differential (i.e., u-tube) pressure. The wellbore is then isolated above all barriers to be tested using a BOP, packer, valve, wellhead test tool, etc. The displacement pressure is bled off, imposing a differential underbalance pressure on the barriers to be tested. The well is then monitored for flow or pressure for a period of time, and the test results are recorded and compared to those expected to determine the success of the test.

For an inflow test, consider the following activities:

- Ensure that all mechanical barriers inflow tested are rated for anticipated pressures. Perform an analysis to ensure that the collapse rating of barriers is not exceeded (e.g., casing collapse, liner packer, body or PBR collapse):
    1. When using test ram or bi-directional ram in the BOP, the test places differential pressure across the BOP in the proper direction. However, if a test ram is used, consider closing a conventional BOP to prevent an influx from entering the marine drilling riser in the event of a barrier failure.
    2. When using a conventional BOP, the test places differential pressure across the BOP in the improper direction. Contact the BOP's manufacturer for the amount of inflow (if any) that the BOP can withstand or other mitigating methods.
    3. When using a BOP, verify the collapse pressure the BOP ring gaskets will be exposed to does not exceed their rated collapse capacity.
- If performing an inflow test under a retrievable test tool set in the casing below the wellhead additional testing may be required to test the casing hanger seals.
- Monitor inflow tests for sufficient time period (refer to 7.2.3.2 Verification by Pressure Testing) after stabilization to adequately evaluate mechanical integrity. Monitor annuli for pressure or fluid level changes, which may indicate BOP or other barrier leakage.
- Compare test results to those expected to determine the success of the test. Retain a dated, permanent record of the test.
- Equalize pressure differential across a valve, ram, or annular preventer before opening to avoid damage to the seal.
- Inflow test production casings and liners, including the casing hanger seal assembly and liner hanger/tieback seals, to prove integrity of the seals before abandonment or as required for completion operations. The test shall be made to a pressure level equal to the maximum pressure differential during displacement or, if that is not physically possible, to a level sufficient to indicate barrier integrity.
- Include contingency plan on how to handle potential influx and return well to overbalanced condition in the case of a failed inflow test.

10.2.2 Riser Operational Considerations

10.2.2.1 Running Non-Shearable Items through the BOP

Because of operational and technology limitations, there are cases when non-shearable tubulars are run through the subsea BOP stack such as:

- Drill collars and stabilizers;
- Drillpipe tool joints;
- Large OD and/or thick-walled casing;

- Casing string components such as float collars, stage collars, liner hangers and associated running tools;
- Casing hangers and associated running tools;
- Retrievable casing bridge plugs and storm packers;
- BOP test plugs;
- VIT;
- Completion components such as packers, mandrels, hangers and sand control screens.

When a non-shearable tubular or component is run or pulled through the subsea BOP stack, additional operational precautions shall be used to minimize the likelihood of a well influx or a loss of stationkeeping (requiring a marine drilling riser disconnect). These may include:

- Additional supervision on rig floor (toolpusher, company rep, etc.);
- Heightened sense of awareness on bridge (DP Operator, thruster adjustments, etc.);
- Heightened sense of awareness throughout rig (announcement over Public Address system, etc.);
- Additional verification of well stability;
- Additional verification of weather window.

  Note: Refer to API RP 53 on non-shearable items.

10.2.2.2 Marine Drilling Riser Operating Limits

It is essential to analyze and establish marine drilling riser operating limits for expected metocean conditions. Managing marine drilling riser system integrity is a vital part of managing well control in DW well designs. Consider the following in the marine drilling riser analysis:

- The minimum and maximum allowable tension for safe operation of the marine drilling riser. For DP rigs, the minimum marine drilling riser top tension provides sufficient tension at the connector between the LMRP and BOP stack so that the LMRP is lifted off the lower BOP stack in an emergency disconnect situation. The minimum top tension also prevents buckling at the bottom of the marine drilling riser. The maximum marine drilling riser top tension is governed by marine drilling riser, connector, and marine drilling riser tensioner capacities, and marine drilling riser recoil issues.
- The maximum weather conditions under which the marine drilling riser can be run, retrieved, or hung-off. See API RP 16Q for additional information about marine drilling risers and maximum weather conditions.
- Riser hang off calculations at various of deployed riser;
- Fatigue analysis for the marine drilling riser if high currents are expected at the location. In some cases, using vortex-induced vibration suppression devices (strakes or fairings) over the depth interval of the highest currents can be necessary for the marine drilling riser to achieve an acceptable marine drilling riser system fatigue life. Note that the use of vortex-induced vibration suppression devices will increase riser deployment/retrieval time which can be an important consideration for hurricane evacuation planning.

Additionally, supplement the marine drilling riser analysis with a marine drilling riser inspection and maintenance program to help ensure integrity of the system.

10.2.2.3 Marine Drilling Riser Disconnect

If the drilling rig experiences a loss of stationkeeping ability, an emergency disconnect of the marine drilling riser system can be required to prevent serious damage to the marine drilling riser system, subsea BOP stack, or both systems. An emergency disconnect involves executing a pre-programmed BOP control system sequence. The EDS function is pre-programmed to close the BSR(s), and release the LMRP connector. Consider the time required to complete all of the EDS-related functions, as part of the site-specific marine drilling riser analysis.

For dynamically positioned rigs, the rate a powerless vessel will drift is used to establish the distance from the wellhead at which the EDS must be initiated to ensure the LMRP is disconnected prior to damaging the marine drilling riser system or subsea BOP stack. This distance indicates when the EDS must be initiated to complete the disconnect process before the rig reaches the point of disconnect. Watch circles are established to ensure the offset distance for EDS initiation is clearly communicated to all rig operations staff. A well-specific operating guide for the DP operators provides additional detail to ensure that any variations in a DP rig's stationkeeping ability are considered.

Certain well construction activities can impact the watch circles for DP rigs. For example, if a subsea test tree is installed in the subsea BOP stack for the purpose of a well flow back to a DP rig, the operator may elect to function the subsea test tree to isolate the tubing flow path before the normal EDS can begin. Assuming that the same control pod is still appropriate in this example, the use of the subsea test tree requires defining a smaller operating circle to accommodate the associated longer EDS time.

10.2.2.4 Riser Wear Considerations

Marine drilling riser operating limits for routine drilling or completion operations in DW are established to prevent wear within the marine drilling riser system for tripping pipe or pipe rotation. This starts by establishing the maximum allowable inclination for the subsea wellhead. After the marine drilling riser and BOP stack are run and latched to the wellhead, BOP stack inclination and marine drilling riser angle sensor data from the lower flex joint or ball joint are monitored as part of the marine drilling riser integrity management system to ensure that operations are not conducted if the flex joint angle exceeds established limits.

Subsea currents acting on the marine drilling riser can affect the shape of the marine drilling riser and cause increased wear. The use of loop current tracking services or acoustic Doppler current meters may be used for measuring surface currents and current profile versus depth at a specific location.

During drilling operations, avoid shallow testing of logging while drilling tools with motors or reamers in the BHA to avoid damaging the ID of the marine drilling riser. Rotating tools with strong side-cutting action (such as some bit types, bi-center bits, and hole opening reamers) inside the marine drilling riser can gouge the marine drilling riser.

During well operations, a ditch magnet is normally placed in the mud return flow path to collect steel particles. Daily weighing of the collected steel particles provides a way to detect abnormal wear in the well or marine drilling riser system. A best practice is to periodically inspect all marine drilling riser system components for internal wear. This can be done between wells or if the marine drilling riser is retrieved for temporary abandonment. Alternatively, caliper surveys or other evaluation logs can be run to periodically measure wear.

10.2.2.5 Potential for Gas in the Riser

In general, the solubility of gas in formation fluids and drilling mud increases with the pressure of the fluid and the type of fluid system used. NAF mud systems have higher gas solubility than water-base mud. In DW drilling and completion operations, detection of a small gas influx into the wellbore that goes into solution can be masked. The gas influx only becomes apparent (e.g., from an increase in return flow rate or pit gain) when it starts breaking out of solution above the subsea BOP stack inside the marine drilling riser.

The bubblepoint of the formation fluid may occur at a depth above the BOPs and in the riser. After the gas starts coming out of solution, expands, and is circulated higher in the marine drilling riser, the volume to which the gas expands may unload the drilling fluids in the marine drilling riser. To prevent expanding gas from being vented onto the rig floor, a diverter system and its associated overboard vent lines provide a way to safely vent expelled mud and gas through the downwind vent lines away from the rig. Any time the diverter system is activated in a well control situation, close the subsea BOP to seal the wellbore and prevent further influx of formation fluids. When activated for well control, the diverter system is set to divert flow overboard through large diameter flowlines. Routing the marine drilling riser fluids to another location, such as the mud gas separator, is possible on some rigs; however, this should only be done in a non-emergency situation and never during a well control event. Routing mud returns from the diverter lines through the mud gas separator should be an activity carried out under the strict controls of a work permit, as it interferes with a safety system. Valves should be returned to the default overboard position on conclusion of the permit activity.

Because the typical marine drilling riser telescopic joint sealing element is not a pressure rated sealing element, the diverter and vent line system is designed to allow large liquid and/or gas flow rates while exerting minimal backpressure on the telescopic joint sealing elements.

10.2.3 Casing Wear

Casing/liners are a fundamental element in the well control barrier system. Proper design, quality assurance, installation, and cementation of the casing must be addressed for it to be a viable well control barrier. However, when installed, it is crucial that operations are conducted in a manner that protects the integrity of the casing.

Casing wear is caused by pipe movement (axial and rotational) and side loads of a tool joint against the casing. Drillpipe sideloads are a function of dogleg severity and drillstring tension at the point of the dogleg. Other factors that can increase the wear rate are drilling fluid composition and lubricity, the drillstring hard banding, and total rotating hours.

Consider the following risk mitigations for casing wear:

a) Directional plans that avoid shallow doglegs, especially in deep wells;

b) Analysis to avoid buckling caused by thermal effects and mud-weight changes in the well design. Buckling can be severe when the casing passes into an enlarged hole size wash out, or rathole;

c) Select tool joint hard banding that offers a reduction in casing wear;

d) Include casing wear predictions in the casing design and include casing wear tolerance in the casing program. Run thicker walled casing to allow for casing wear where wear is expected;

e) Use non-rotating drillpipe standoff devices or rotating drillpipe rubber protectors;

f) Monitor the effect of wear on connections, including a review of the amount of wear that would cause the connection to leak This is especially critical for flush or semi-flush connections, which usually have a metal-to-metal seal on a formed pin that has a reduced ID;

g) Reducing abrasive solids in mud;

h) Increasing casing hardness;

i) Mud composition for lubricity.

If casing wear is believed to be a concern, monitor casing for wear during well construction activities. While drilling, ditch magnets can be installed and the weight of steel cuttings recovered can be measured, recorded and plotted versus rotating hours to develop a qualitative measure of the wear rate and if changes in wear rate occur.

Periodically (or as specified by regulation), the casing can be callipered or pressure tested to ensure that it remains a viable barrier. While pressure testing may offer evidence of the casing viability as a barrier at the time of the pressure test, the casing caliper is able to measure the wear and compare actual wear rate and location of casing wear. The casing caliper data offers the ability to take action to mitigate future casing wear.

NOTE: For machined surfaces, such as formed pin connections, a very accurate reading of ID can be obtained whenever the caliper is run though the connection. Therefore, a baseline log for pipe with this kind of connection may not be required.

10.2.4 Heat Checking

During the drilling and well services process, mechanical and metallurgical degradation of the casing integrity can occur from drillstem interaction with the casing. This interaction may result in casing wall loss from wear or cracking due to heat checking. Heat checking in casing is thought to be a result of the drillpipe rubbing against the ID of casing during normal drilling operations. Friction associated with the rubbing action causes shallow, localized contact points in the ID of the casing to heat to extremely high temperatures (±1,500°F). As the drilling fluid contacts the heated region, the contact points rapidly cool, which transforms the microstructure of the casing ID and results in localized brittle areas and cracking. High drillpipe side loads are present in the regions where the heat checking cracks form, the cracks can continue to grow and cause a casing leak

Heat checking is most prevalent in sections of a well where high drillstring side loads occur. These conditions are especially prevalent in the upper casing sections of very deep wells (30,000 ft+) with high dogleg severity.

Heat checking has also been reported in the first 50 ft to 80 feet below the casing hanger. In this area, it is directly related to the drillpipe side loading from transitioning from the marine drilling riser into the wellhead/intermediate casing. Minimizing the angle between the flex joint and the BOP stack reduces potential side loads at or near the wellhead. The inherent effects of surface and subsea loop and eddy currents on MODU rig positioning may cause the drillstring to develop greater side loads in the wellbore, which is often at or directly below the wellhead or casing hanger joint.

Heat checking occurs independent of the yield strength of the material. It is a result of heating to the austenization temperature which negates effect of previous quench and tempering. However, limited field experience with higher strength casing has shown that V150 casing and above appears to be more susceptible to heat checking. A number of drilling conditions can impact drillpipe side loading such as:

- Wellhead alignment (affected by vessel offset);

- Wellbore deviations (dogleg severity, abrupt doglegs);
- Marine drilling riser/wellhead alignment with the BOP stack;
- Drillstring tension.

To mitigate the risk of heat checking, consider:

- Running thick-wall casing immediately below the casing hanger on long protective casing strings installed in deep wells;
- Using non-rotating drillpipe standoff devices;
- Designing the drillstring to minimize drillpipe side loads;
- Ensuring the compatibility of hard banding on drillpipe with higher-grade casing materials;
- Running a wear bushing with an ID less than the casing ID or nested wear bushing assembly to protect the area most likely to encounter heat checking;
- Reducing rotating time and rotary speed;
- Using fluid lubricity agents;
- Monitoring the drillstring tool joints for evidence of excessive heating.

11 Completion Operations Considerations

11.1 Completion Operation Phases

The four general phases of a completion operation are:

a) Wellbore preparation;

b) Lower completion;

c) Upper completion;

d) Cleanup or flow initiation.

Physical barriers installed during temporary abandonment of a drilled well are removed and then replaced with other barriers during the wellbore preparation and re-entry phases. Operations, such as wellbore displacements, sand control, stimulation perforating, and circulating packer fluid, often place non-kill-weight fluids in the wellbore. At or near the end of the completion process, additional physical barriers are installed in the well before kill-weight fluid is removed from the riser and the BOP stack removed. The removal of previously tested barriers and removal of kill-weight fluids creates the potential for well control incidents; therefore, during the well completion process, the appropriate barriers shall be in place at all times.

11.1.1 Wellbore Preparation

The first phase of a completion is the wellbore preparation phase. This phase may include re-entry of a suspended or temporarily abandoned well, BOP installation and testing, drilling cement plugs, wellbore displacement, electric line operations, and remedial cement operations.

Before beginning the wellbore preparation phase, the BOP ram configuration shall be confirmed to be suitable for all planned completion operations. The confirmation includes verifying the ability of the BOP to shear all planned drillpipe and conventional tubing to be used and the pressure rating of the ram BOP's are greater than MAWP for all anticipated completion operations. Refer to API RP 53 for more information on determining shearing pressures.

11.1.1.1 Well Re-Entry

Re-entry in a well involves removing physical barriers installed during drilling operations. These barriers consist of:

- Retrievable mechanical devices, such as storm packers;
- Drillable barriers, such as cement plugs, cement retainers, or bridge plugs.

The potential exists for trapped pressure or hydrocarbons to be present below the barrier. Confirm well integrity above the barrier before removing a barrier.

11.1.1.2 Wellbore Displacement

For information, see Section 10.2.1.

11.1.1.3 Remedial Cement Operations

When remedial cement operations are required, revise the barrier plan to consider possible squeeze perforations, as well as the suitability of any new barriers. The wellbore integrity must be validated for all remaining completion operations.

11.1.2 Lower Completion

The lower completion phase may include perforating, stimulation, and/or sand control operations. During this phase, barriers may be removed and non-kill-weight fluids may be used. As in the wellbore preparation phase, review the barrier plan for any changes to barriers during this process.

11.1.2.1 Perforating

Perforating can be done with wireline- or tubing-conveyed perforating guns. DW perforating operations typically use tubing-conveyed perforating systems, which consist of these primary components:

Perforating assembly:	Includes the perforating guns, which are hollow steel carriers with perforating charges along with the firing systems
Retrievable packer and downhole circulating tool:	Used to provide a way to circulate the well in a controlled manner, help control fluid loss, and facilitate placement of fluid loss pills

Tubing conveyed perforating guns may be non-shearable items or may impede the ability to shut in the well if they are positioned across the BOP. See Section 10.2.2.1 *Running Non-Shearable Items through the BOP* for mitigation measures used to deploy and recover the tubing conveyed perforating assembly. A barrier plan to mitigate risk during perforating gun running and retrieval should be developed.

Perforating can be carried out with either an underbalanced or overbalanced hydrostatic column. Consider the following issues that may occur after perforating:

- Trapped gun gas;
- Circulating out and handling hydrocarbons at the surface;
- Plans for fluid loss control and maximum accepted fluid loss rate prior to tripping the guns out of the hole;
- Trip margins.

11.1.2.2 Stimulation

Numerous types of stimulation operations and sand control techniques are employed in DW completions. These operations involve pumping fluids of varying densities, pumping different types of acids, pumping fluids that can be corrosive or have adverse effects on sealing elements, pumping abrasive proppant, and pumping with high treating pressures.

Gravel pack screens and completion equipment may be non-shearable items or may impede the ability to shut in the well if they are positioned across the BOP. See Section 10.2.2.1 *Running Non-Shearable*

Items through the BOP for mitigation measures used to deploy or recover completion equipment. A barrier plan to mitigate risk should be developed.

Pumping operations often incorporate downhole tools that require surface manipulation during different steps in the job. The position of tool joints relative to the pipe rams, shear rams, and annular BOP shall be addressed when spacing out the tools to account for different tool joint location due to surface manipulation of the downhole tools.

The mixing and pumping of fluids may be done from equipment mounted on the rig or from a separate stimulation vessel. When utilizing a separate stimulation vessel, coordination between the rig and the stimulation vessels is necessary when monitoring annulus and drillpipe pressures, when shifting the position of the downhole tool, during pumping operations, bleeding off pressures, and when deciding what to do if the stimulation vessel is not able to keep station next to the rig. A coordinated effort shall be made between rig personnel, service providers, and the operator to examine all aspects of the operation related to well control.

When performing certain stimulation operations, the annular preventers or pipe rams are often closed to allow annular pressure monitoring. Casing and work string designs shall consider anticipated treating conditions and pressures. Annular preventers and pipe rams shall also be tested using the maximum anticipated treating pressures they will receive.

While performing stimulation activities, it is important to accurately monitor fluid volumes and rates. During stimulation and sand control operations, it is often necessary to forward- or reverse-circulate treating fluids in the wellbore. The stimulation fluids can be non-kill-weight and, if not monitored closely, these operations can create an influx of reservoir fluids into the wellbore. The well condition should be confirmed before pulling out of the hole following a stimulation or sand control operation.

NOTE: Post-stimulation fluid loss rates can be high.

11.1.3 Upper Completion

The uphole completion phase operations include running and landing the production tubing. The production tubing string will consist of joints of tubing and some or all of the following completion components:

- Production packer;
- Flow control devices;
- Pressure gauges;
- Chemical injection mandrels;
- Surface controlled subsurface safety valve (SCSSV);
- Vacuum insulated tubing;
- Tubing hanger.

Most downhole completion components use encapsulated control lines for hydraulic or electric power. These encapsulated lines are externally clamped to the production tubing. While running the uphole completion through the BOP stack, it is important to note that the pipe rams and annulars will not reliably seal on the production tubing and encapsulated control lines. The shear rams may also not be able to shear certain components of the tubing string.

An inhibited packer fluid is usually circulated in the well following running of the production tubing. The packer fluid may be a non-kill-weight fluid. Before displacing the packer fluid, confirm the integrity of the tubing hanger locking mechanism and seal. This may be done on initial installation by the shearing of shear pins or lead impression block imprints. After installation, pressure tests may be used to confirm integrity. Typical parameters that are monitored during displacements operations to help detect a well control event are:

- Pump pressure;
- Flow rate in and out;
- Pit volume.

The production packer is also set and tested during this phase following displacement of the packer fluid.

After the tubing hanger is landed and tested and the tubing hanger running tool is connected to the tubing hanger, the pipe rams, or annulars are no longer primary well control devices.

11.1.4 Flow Initiation

The final phase of the completion may be well flow initiation. After the uphole completion is run and landed, a final assurance should be made of the operability of all completion components. This includes verifying all barriers such as packers, seals, tubing hanger, SCSSV, and any flow control devices. After the tubing hanger is landed and tested, the pipe rams and annulars are no longer primary well control devices.

After the tubing hanger is landed and tested, the pipe rams and annulars are no longer primary well control devices. Well initiation operations may include flowing through temporary production facility located on the rig downstream of the surface test tree. The temporary facility shall be designed to manage the anticipated flow rates and pressures according to all regulatory requirements. Once pressure and integrity testing have been completed, flow is initiated. Operating parameters are monitored during the flow test. It is common for the production casing by tubing annulus to have an increase in pressure due to the higher temperatures of the produced reservoir fluids. A means to maintain this pressure below well design limits will be required.

A subsea test tree (SSTT), EDP, or LRMP of a completion riser is deployed to allow an emergency disconnect. An emergency disconnect plan should be established prior to initiating well flow. These allow the well to be shut in at the mudline.

The SSTT can be disconnected below the BSRs, which acts as a physical barrier. The SSTT will contain a retainer valve that can be closed to prevent hydrocarbons from escaping the landing string following the disconnect sequence. An emergency shutdown plan and EDS plan should be established for all tree types.

11.1.5 BOP Stack Removal

Before removing the BOP stack, the physical barriers to flow on the annulus and production bore shall be verified. On the annulus side this would include the tubing hanger annulus seal and production packer.

The physical barriers shall be tested in the direction of flow if possible. If a fluid loss device is isolating the producing formation, both the tubing hanger annulus seal and production packer can be tested from below, although only to the pressure rating of the fluid loss device. Pressure ratings of items such as downhole pressure temperature gauges may limit the test pressure that can be applied. The tubing hanger annulus seal shall be tested to MASP from above prior to removing the BOP stack.

The tubing string can be pressure tested when setting the production packer. The SCSSV can be inflow tested in the direction of flow by closing the SCSSV, bleeding off pressure above the SCSSV, and monitoring the fluid volume.

If a horizontal subsea production tree is used in the completion, each of the dual crown plugs shall be independently pressure tested to MAWP before displacing the riser and removing the BOP stack. Some designs allow inflow testing of the crown plugs.

11.2 Well Testing and Unloading Considerations

The following items should be considered for well testing and unloading hydrocarbons to a floating rig with a subsea BOP stack:

- Barriers;
- Completion/work string and high pressure riser components;
- Surface well control equipment;
- Conditions monitoring while flowing the well;
- Considerations for rig motion on a floating rig;
- Emergency shut-down and disconnect plan.

11.2.1 Well Testing Barriers

When flowing hydrocarbons to the rig, the appropriate barriers shall be in place per section 7*.2 Barrier Philosophy* and Annex B in this recommended practice.

The process for unloading the well to the rig during completions is determined by the type of tree used. Historical examples include the following:

Conventional drillstem test	Performed with the subsea test tree landed in the subsea wellhead. The subsea BOP stack and marine riser are attached to the wellhead. The test string consists of the following items: — Retrievable packer, tubing string with annulus pressure activated tester valve and annulus pressure activated circulating valve, and subsea test tree is landed in the subsea wellhead. BOP pipe rams are closed on the subsea test tree. — SSTT, landing/test string, surface flow head.
Completions with a horizontal tree	Performed with the tubing hanger landed in the horizontal tree. The subsea BOP stack and marine drilling riser are attached to the horizontal tree. The test string consists of the following items: — Production packer, tubing string with SCSSV, tubing hanger landed in the horizontal tree;

	— SSTT, landing string, high pressure tubing riser, and surface flow head.
Conventional drillstem test	Performed with the subsea test tree landed in the subsea wellhead. The subsea BOP stack and marine riser are attached to the wellhead. The test string consists of the following items: — Retrievable packer, tubing string with annulus pressure activated tester valve and annulus pressure activated circulating valve, slip joint, and subsea test tree is landed in the subsea wellhead. BOP pipe rams are closed on the subsea test tree. — SSTT, landing/test string, surface flow head.
Completions with a vertical tree	Performed with the subsea production tree attached to the wellhead (or tubing spool). A LMRP and EDS are used to install the vertical tree and: — Production packer, tubing string with SCSSV, tubing hanger landed in the wellhead or tubing spool; — LMRP, EDS, high pressure riser, surface flow head, and surface well control equipment.

11.2.2 Well Testing Operations

For well testing operations without subsea production trees, the typical configuration may include:

- Packer, tubing string with circulating valve, downhole shut-off valve, and fluted hanger in subsea wellhead;
- SSTT, high pressure test (tubing) riser, surface flow head, and surface wellhead equipment;
- Completion/work string.

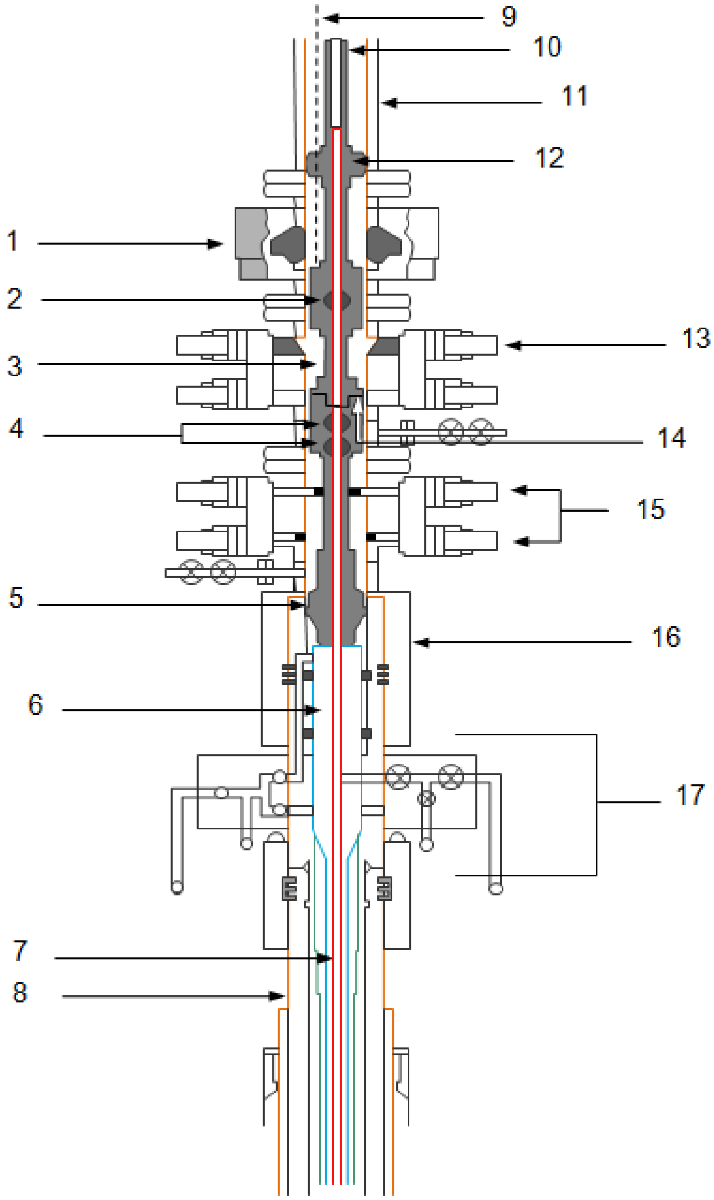
The following guidelines apply to the completion work string and high pressure tubing riser components:

- All components in the completion string and high pressure tubing riser should have gas-tight premium connections.
- For completions, the SCSSV shall be placed at an appropriate depth below the mudline, be of failsafe closed type, and controlled from the surface.

Verify these component conditions to ensure well control at all times during testing before bringing the well on stream:

- All defined barriers and surface test system shall be tested and verified according to plan.
- The SSTT should be positioned so that the BSR can be closed, shearing the shear joint and sealing the well.
- As part of DP rig’s emergency disconnect sequence: 1) the SSTT should be capable of closing and disconnecting prior to BSR closure; 2) a passive motion compensation system should be

capable of lifting the high pressure riser after the SSTT disconnect or shearing of the SSTT shear joint.



Key

1. annular BOP
2. retainer valve
3. shear sub
4. ball valve
5. tubing hanger running tool
6. tubing hanger
7. production tubing
8. wellhead
9. hydraulic control lines
10. landing string
11. riser
12. centralizer
13. BSR BOP
14. latch connector
15. pipe ram BOP
16. BOP connector
17. subsea production tree

Figure 11.1: Subsea Test Tree

11.2.3 Surface Well Control Components

11.2.3.1 Surface Flow Head

A typical arrangement for a surface flow head is shown in Figure 11.2.

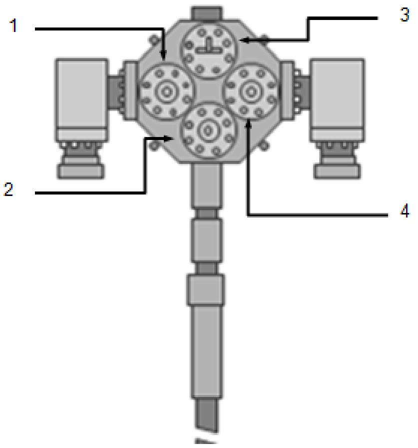


Figure 11.2: Surface Flow Head

Key

1	kill valve	3	swab valve
2	master valve	4	production valve

11.2.3.2 Slickline, Wireline, and Coil Tubing

When wireline and/or coil tubing is used, additional lubricator valves and surface wireline BOP systems are installed on top of the surface flow head.

11.2.3.3 Slickline

Slickline rig-up (RU) uses these components:

- Stuffing box, including a blowout plug or a ball check valve (for live well intervention);
- Tool catcher;
- Lubricator;
- Cable ram (maintaining pressure from below);
- Shear seal ram (independent hydraulic operated for live well intervention).

11.2.3.4 Wireline

A braided or electric line RU consists of:

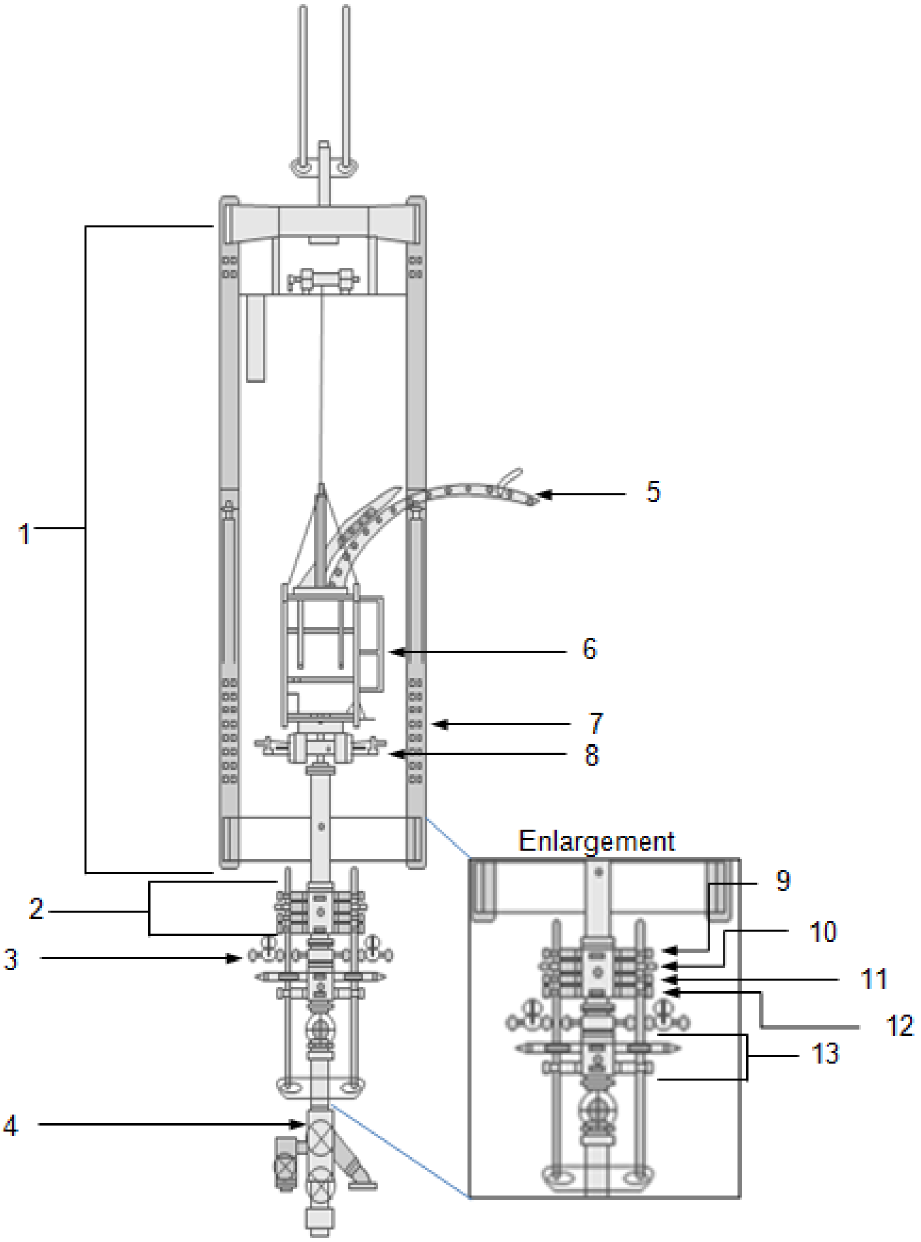
- Packoff head for dead well intervention of grease injection head for live well intervention, including integral ball check valve, and a minimum of three for each flow tubes;
- Tool catcher;
- Lubricator;
- Cable ram (maintaining pressure from below);
- Cable ram (maintaining pressure from above);
- Shear seal ram (independent hydraulic operated for live well intervention).

11.2.3.5 Coil Tubing

A coil tubing (CT) RU operation on a floating rig uses:

- Dual strippers with rubbers and bushings for the intended size of CT;
- Triple CT BOP dressed with (from top): shear ram, pipe ram, and slip ram or;
- Triple CT BOP dressed with (from top): shear or seal ram, pipe ram, and slip ram.

Note: Reference API RP 16ST.



Key

1	lifting frame	6	injector	11	slip ram
2	coiled tubing quad BOP	7	coiled tubing lift frame	12	tubing ram
3	flowcross	8	stripper packer	13	dual combo BOP
4	frac head	9	blind ram		
5	coiled tubing guide	10	shear ram		

Figure 11.3: Coil Tubing and Lift Frame

11.2.4 Monitoring of Conditions While Flowing the Well

Monitor these conditions while flowing the well:

- Annulus pressure and trip tank level;
- Disconnect capability in the event of a stationkeeping loss;
- Potential for hydrate formation. Make sure that the appropriate mitigation measures are in place.

Monitor the annulus pressure and trip tank level during flowing and shut-in periods, including the following:

- Providing ability to reverse circulate;
- Bleeding-off fluid to a calibrated tank.

Prepare operation plans for these scenarios:

- Killing the well;
- Preventing of hydrates;
- Providing safety guidelines for personnel in the event of poisonous gas in the well stream.

11.2.5 Floating Rig Motions

Consider rig motion to provide appropriate motion compensation for the surface flow head, surface well control equipment, and high pressure riser. This compensation may include a lift frame. Note: the proximity of the surface flow head and flowlines to the drill floor may also limit allowable rig offset, and it is considered in developing watch circles for well flowback/testing operations.

12 Management of Change

12.1 Unexpected Events

Unexpected events or circumstances may require a change to the well design during execution of activities. In some situations, these changes can affect the integrity of the well and/or barriers.

Each operating company shall develop its own practices and policies regarding management of change (MOC). The MOC process should include a clear description of the change, evaluation of risk, and approval of the MOC commensurate with the impact of the change. In some situations, changes to well conditions or equipment may also require regulatory approval to continue operations.

Risk management processes shall be used during well design, planning and execution activities, and are critical to safe management of changes associated with unexpected events. Risk assessments should identify failure modes, consequences, the actions and equipment necessary to secure the well at any time during the operation, required controls and safeguards, and a process by which these risks can be mitigated or managed. Refer to DNV-RP-H101, API RP 75, and API Bull 97 (work in progress) for more information on risk management.

Implementing an MOC process as part of the well planning and execution process, allows a company to effectively manage, track, review, and approve changes of the drilling and completion process.

Examples that may use the MOC process are:

- Assumptions or data in the original well design that is no longer valid.

  Pore pressure or fracture gradient is different than the pre-drill prediction which may result in a well design change. These changes often result in different loads and design factors for the well.

- Failure of equipment used in the original well design (or the original equipment is not available).

  The equipment and components used in well construction occasionally fail. These failures can compromise the well integrity.

- Other types of operational difficulties encountered during DW drilling and completion operations.

  Lost returns, either while drilling ahead or while installing casing/liner, is common. In some situations, these problems can ultimately require a change in well design to accomplish the original well objectives or to meet policy/regulatory requirements.

- Change in well scope.

  An expendable exploration well changes to a production well or a well designed for production is used as an injection well. Changes of this type need to be carefully managed to avoid adversely affecting well integrity.

12.2 Contingency Well Plans

The well engineer generates contingencies during planning to address scenarios that may require a deviation from the original well design. When the options are sufficiently developed and vetted with stakeholders, then the MOC process may use these plans to support the changes.

12.3 Stakeholder Interface

Stakeholder alignment and agreement, down to the detail of the well design and procedures, enhances the well delivery process. The well operator interfaces with the rig contractor and other third-party equipment and service suppliers as determined by well-specific information. Interfacing with stakeholders facilitates management of any changes that may occur. Refer to API Bulletin 97 (work in progress) for more information on management of change and contractor interface regarding well design.

12.4 Stop Work Authority

The rig management system shall include a stop work authority (SWA) process with a “non-reprisal” policy to allow all personnel to freely express their concerns. The SWA process provides all operator and contractor/service personnel directly or indirectly involved with the operation the responsibility to pause operations until the appropriate review of the activity can be concluded. This may include review by an independent supervisor (one not involved in the job) or implementation of an MOC before operations are resumed. An example may progress as follows:

- Stopping the possible at-risk act, behavior or event;
- Notifying the supervisor or appropriate authority;
- Addressing the issue;
- Resuming work;
- Documenting the lessons learned.

Annex A

(Informative)

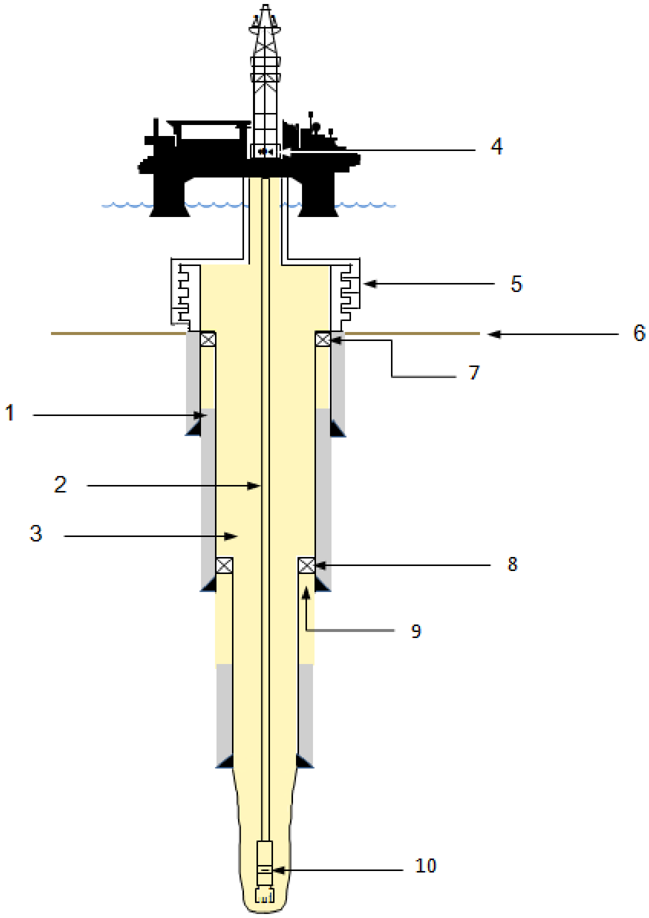
Examples of Barriers Employed During Operations

The tables in Annex A represent examples of operations conducted during the drilling and completion of DW wells. The tables list well barriers that may be used in the wells to maintain control by preventing flow through the alternative pathways that are present during that particular operation. The tables also describe some details about the well barriers.

Annex A is not intended to capture every possible operation or well configuration. The well barriers that are listed represent only one alternative configuration, and the tables in Annex A do not preclude other configurations of barriers. Similarly, the tabulated verification methods that ensure that the well barrier was properly installed represent only one way to perform the verification.

The following operations are described in this annex:

- Table A.1: Drilling Ahead
- Table A.2: Emergency Evacuation/Disconnect/BOP Repair (LMRP Removal only)
- Table A.3: Abandonment (Full BOP Stack Removal)
- Table A.4: Tripping After Tubing-Conveyed Perforating
- Table A.5: Flowback through Production Tubing to Rig



Key

1 casing to casing annuli
2 drillpipe
3 drillpipe to casing annulus
4 stab-in FOSV
5 BOP stack
6 mudline
7 casing hanger seal
8 liner hanger packer
9 liner to casing annulus
10 drill string float valve

Yellow shading indicates drilling mud.

NOTE 1 A flowpath scenario inside the drillpipe would encounter the following barriers: drillstring float (if present), drilling fluid (hydrostatic only if overbalanced), drillpipe, and a stab-in full-opening safety valve (FOSV) or internal BOP in the top drive. Operationally, influx detection, recognition, and response occur inside the drillpipe.

NOTE 2 A flowpath inside the drillpipe-to-casing annulus would encounter the following barriers: drilling fluid (hydrostatic barrier only if overbalanced), liner shoe, liner, liner hanger seal, intermediate casing, wellhead casing hanger seal, and BOP. Operationally, influx detection, recognition, and response occur from drillpipe to casing annulus.

NOTE 3 A flowpath up the liner and casing annuli to the mudline would encounter the following barriers: liner cement, liner hanger seal, casing cement, outer casing and cement, and wellhead hanger seal.

Figure A.1: Drilling Ahead

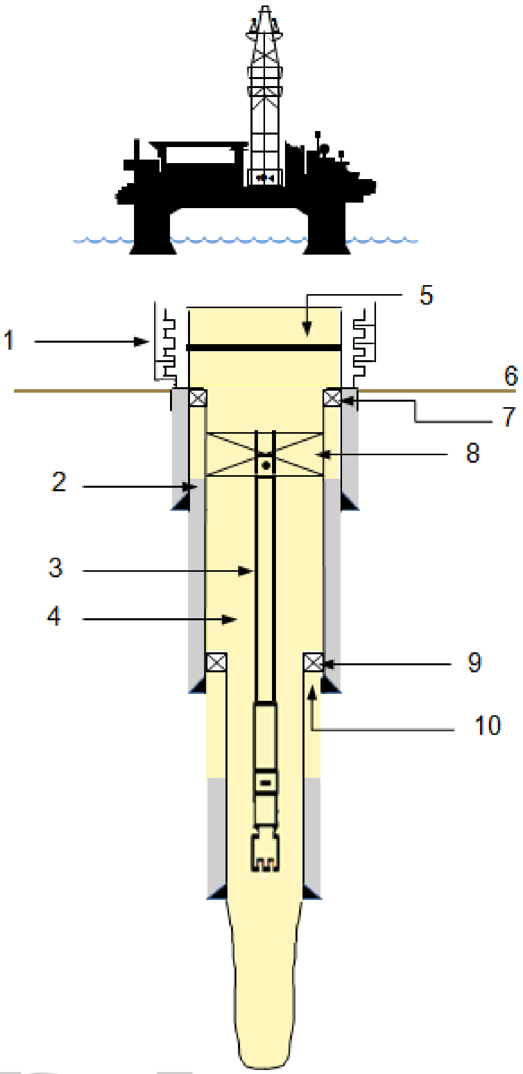
See Table A.1 for a description of available barriers for this operation.

Table A.1: Drilling Ahead

Casing Configuration / Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Barrier Type	Special Considerations
Inside drillpipe	Drillpipe float	Function check during trip into hole.	Mechanical	— Not routinely pressure tested. — Suggest recording function check in tourly reports. — Some rigs may use ported floats that communicate pressure at a very small flow rate. Other rigs may use non-ported floats.
	Drilling fluid	Mud checks confirm density.	Hydrostatic	Adjust mud-weight as needed
	Drillpipe	Function check during circulation operations.	Mechanical	— Not routinely pressure tested. — Periodically inspected for body and thread condition.
	FOSV or internal BOP (Kelly valve)	— Pressure tested with BOPs. — Stab-in drills performed to assess operational readiness.	Mechanical, requires operational barrier	— FOSV can be installed on a drillpipe connection at the rig floor and then closed. Top drive may have internal BOP. — Ensure thread compatibility or cross-overs to the drillpipe. — Minimizing the time required to install the FOSV is critical.
	If actuated, BOP BSRs are designed to seal above the drillpipe that they shear	Sealing capability of BSR is tested along with BOPs.	Mechanical, requires operational barrier	— Capability to shear and subsequently seal is not routinely tested once installed. — Good practice to position drill string so tool joint is not across BSR(s) during well control response. — Not all shear rams are designed to seal.
Inside casing	Drilling fluid	Mud checks confirm density.	Hydrostatic	— Adjust mudweight, as needed. — Monitor fluid level in annulus for lost returns. — A trip tank is used during trips into and out of the hole with the drilling assembly. It is filled and continuously monitored. Drills are conducted to assess timely and appropriate response.
	Casing or liner	Pressure test before drillout.	Mechanical	
	Liner top or lap seal (if a liner configuration)	Pressure test before drillout.	Mechanical or cement	— Use of a dedicated liner-top packer represents a mechanical barrier. — The overlapping casing-by-liner annulus can be sealed with set cement.

Casing Configuration / Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Barrier Type	Special Considerations
Inside casing *(continued)*	Casing hanger seal in wellhead	Pressure test upon installation of casing.	Mechanical	— Refer to 7.2.3.2 for more detail. — Lockdown feature should be engaged before resuming drilling.
	Wellhead	Pressure test upon installation of surface casing.	Mechanical	Include testing of ring gasket between wellhead and BOP stack.
	BOP	Pressure test upon installation and periodically thereafter.	Mechanical, requires operational barrier	— Actuation and proper functioning are required to close the BOP. — Timely actuation of the BOP also requires the detection of an influx and response (i.e., actuation of the BOP). Detection is an operational intervention that combines measurement systems requiring calibration and maintenance (e.g., flow-show and pit volume totalizer) with practices such as the driller flow checks. — Crew recognition and crew response are operational interventions involving training and periodic drills. — C/K line system is considered part of the BOP system. Ensure the barrier will be effective by the periodic circulation of drilling fluid through the C/K lines to prevent plugging.
Outside casing – Long-string configuration	Cement behind casing	— Verified as shown in Table B.3. — Formation integrity test (FIT) after drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify cement placement success.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.
	Casing hanger seal assembly	— Pressure test upon installation. — Inflow test may be performed for production casing hanger.	Mechanical	The seal assembly running tool may also provide an operational indication that the assembly is engaged to the proper location within the wellhead housing.
Outside casing and liner - Liner configuration	Cement behind liner	— FIT after drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify cement placement sucess.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.

Casing Configuration / Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Barrier Type	Special Considerations
	Liner top or lap seal	— Pressure test. — Proper installation. — Monitor cement job placement parameters	Mechanical or cement	— Use of a dedicated liner-top packer represents a mechanical barrier. — The overlapping casing-by-liner annulus can be sealed with set cement. — Consider inflow test for a production liner. — Placement parameters for liners include looking for cement after disconnecting from the liner and circulating at the liner top.
	Cement behind previous casing	— FIT after drillout — Monitor cement job placement parameters — Cement evaluation log techniques can be used to identify cement placement success	Cement	— Test of previous shoe verifies flow from liner annulus will not enter previous casing annulus. — Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.



Key

1 lower BOP stack
2 casing to casing annuli
3 drillpipe
4 drillpipe to casing annulus

5 BSRs (closed position)
6 mudline
7 casing hanger seal
8 storm packer and check valve

9 liner hanger packer
10 liner to casing annulus

Yellow shading indicates drilling mud.

NOTE 1 A flowpath inside the drillpipe is not relevant because of a check valve inside the storm packer.

NOTE 2 A flowpath inside the casing annulus would encounter the following barriers: drilling fluid (hydrostatic barrier only if overbalanced with riser removed), storm packer, and closed BSRs.

NOTE 3 A flowpath up the liner and casing annuli would encounter the following barriers: liner cement, liner, liner hanger seal, casing cement, outer casing and cement, and wellhead hanger seal.

Figure A. 2: Emergency Evacuation/Disconnect/BOP Repair (LMRP Removed Only)

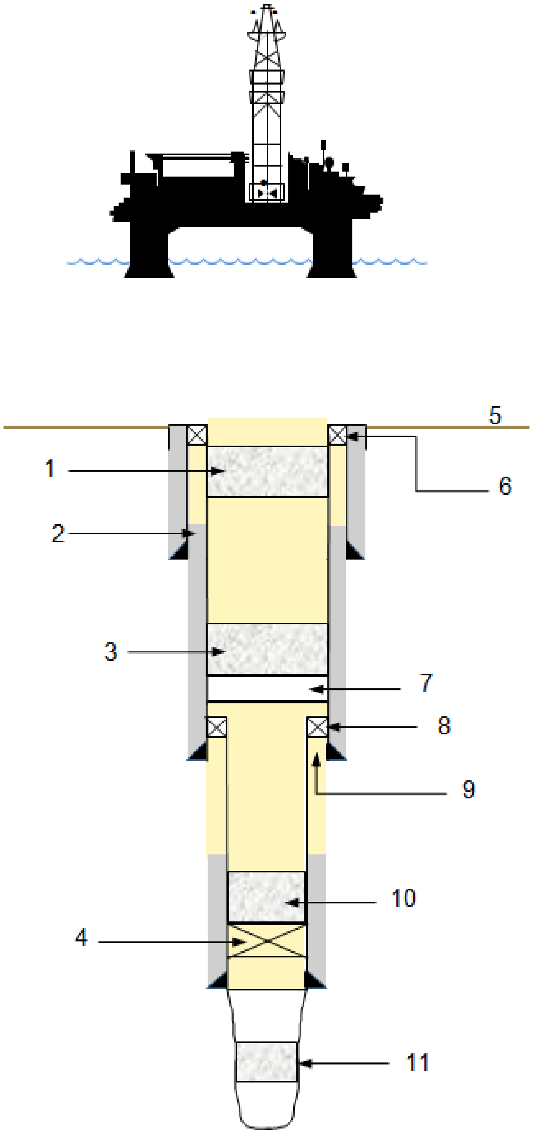
See Table A.2 for a more detailed description of the barriers available for this operation.

Table A.2: Emergency Evacuation/Disconnect/BOP Repair (LMRP Removal Only)

Emergency evacuation or some BOP repairs require removing the LMRP and marine riser only. BOP BSRs remain as a physical barrier. However, the hydrostatic barrier can be lost if the fluid density does not include riser margin. This requires reconsideration of the annular and inner-casing flow paths.

Casing Configuration/ Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Barrier Type	Special Considerations
Inside Casing	Shoetrack (if not yet drilled out)	Verified as indicated in Table B.4 and inflow tested.	Cement	— Conduct inflow test to the maximum hydrostatic differential expected (e.g., marine drilling riser margin loss) prior to disconnecting LMRP. — Cement plug may replace a mechanical plug only if no hydrocarbons are present in the open hole section or in large-bore casings with no mechanical device available. — A check valve inside the storm packer shuts off a potential flow path up the drillpipe.
	Storm packer or Bridge plug	Pressure test	Mechanical	
	Cement plug	Verified as indicated in Table B.5.	Cement	
	Drilling fluid Completion fluid	Mud checks confirm density	Hydrostatic	— Mud checks are relevant only before disconnection. — A hydrostatic barrier can be compromised by “riser margin” loss. The density of the fluid left in the well can be increased to compensate for the loss of the riser hydrostatic in shallower water depths.
	BOP (BSR)	Pressure test upon installation and periodically therafter.	Mechanical, requires operational barrier	— Actuation and proper functioning are required to close the BOP. — For a disconnect, closure of the BSR may be an automatic part of the sequence.
Outside casing – Long-string configuration	Cement behind casing	— Verified as indaicated in Table B.3. — Formation integrity test upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to qualitatively assess the cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time. — Cement evaluation logs are qualitative and subject to interpretation. — If no hydrocarbon reservoir is present in the annulus, it is not necessary to verify the annular cement.

Casing Configuration/ Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Barrier Type	Special Considerations
Outside casing – Long-string configuration *(continued)*	Casing hanger seal assembly	— Pressure test upon installation. — Inflow test (typically only for the production casing hanger).	Mechanical	The seal assembly running tool may also provide an operational indication that the assembly is engaged to the proper location within the wellhead housing.
Outside Casing - Liner	Cement behind liner	— Verified as indicated in Table B.3. — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to qualitatively assess the cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation. — If no hydrocarbon reservoir is in annulus, verification can be a FIT.
	Liner top or lap seal	— Pressure test — Proper installation	Mechanical or cement	— Use of a dedicated liner-top packer represents a mechanical barrier. — The overlapping casing-by-liner annulus can be sealed with set cement. — Consider inflow test for a production liner.



Key

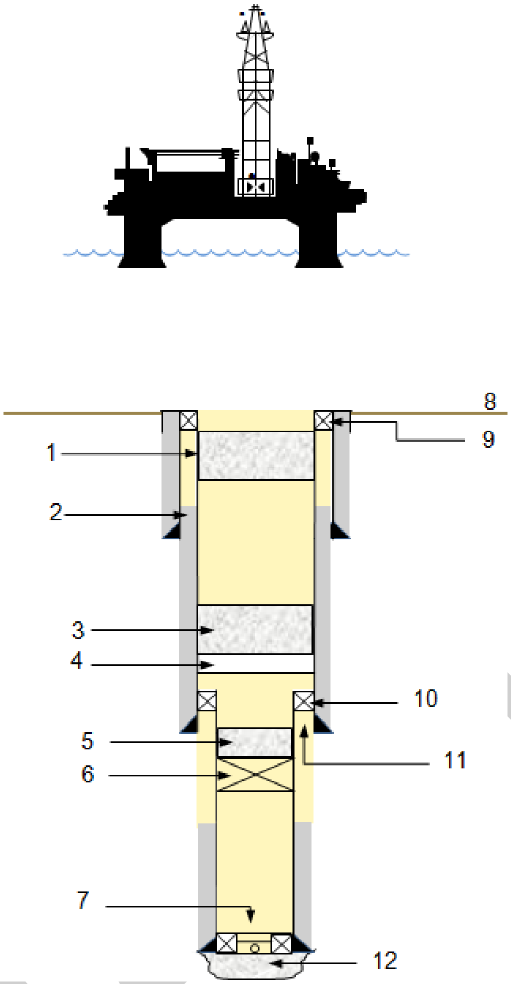
1	surface plug
2	casing to casing annuli
3	cement to top of cement basket
4	cement retainer
5	mudline
6	casing hanger seal
7	cement basket or thick gel pill
8	liner hanger packer
9	liner to casing annulus
10	cement on top of retainer
11	open hole plug

Yellow shading indicates drilling mud.

NOTE 1 A flowpath inside the wellbore would encounter the following barriers: open hole plug, bridge plug or cement retainer inside liner with cement above, liner, retainer above liner top with cement above, casing, and surface cement plug.

NOTE 2 A flowpath up the liner and the casing annuli would encounter the following barriers: liner cement, liner hanger seal, casing cement, outer casing and cement, and wellhead hanger seal.

Figure A.3.1: Abandonment (Full BOP Stack Removal)



Key

1 surface plug
2 casing to casing annuli
3 cement to top of cement basket
4 cement basket or thick gel pill
5 cement to top of retainer
6 cement retainer
7 shoetrack
8 mudline
9 casing hanger seal
10 liner hanger packer
11 liner to casing annulus
12 rat hole

Yellow shading indicates drilling mud.

NOTE 1 A flowpath inside the wellbore would encounter the following barriers: open hole plug, bridge plug or cement retainer inside liner with cement above, liner, retainer above liner top with cement above, casing, and surface cement plug.

NOTE 2 A flowpath up the liner and the casing annuli would encounter the following barriers: liner cement, liner hanger seal, casing cement, outer casing and cement, and wellhead hanger seal.

Figure A.3.2: Abandonment Without Drilling Out the Shoetrack (Full BOP Stack Removal)

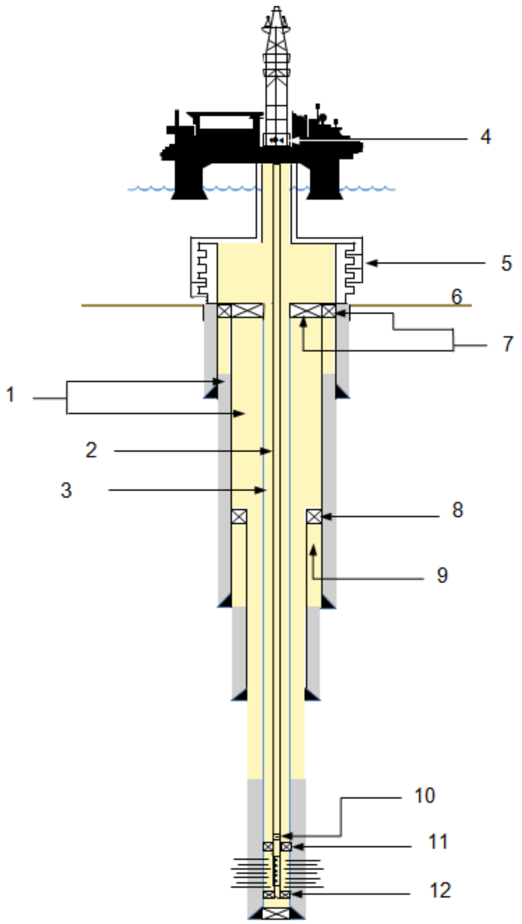
See Table A.3 for additional detail about the barriers available for this operation

Table A.3: Abandonment (Full BOP Stack Removal)

Permanent or temporary abandonment operations require removing the BOP stack and marine drilling riser. This will result in the loss of at least one and probably two physical barriers (the ability to have a closed BOP and the hydrostatic barrier if the fluid density does not include riser margin). Therefore, this operation requires reconsideration of the annular and inner-casing flow paths.

Casing Configuration/Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Inside casing	Shoetrack (as installed)	Verified as indicated in Table B.4 and inflow tested.	Cement	A mechanical barrier shall be used to isolate the shoetrack from the mudline.
	Liner top or lap seal	— Pressure test upon installation. — Monitor cement job placement paramenters. — Proper installation.	Mechanical or cement	— A dedicated liner-top packer represents a mechanical barrier. — The overlapping casing-by-liner annulus can be sealed with set cement. — Consider inflow test for a permanent abandonment. — Placement parameters for liners include looking for cement after disconnecting from the liner and circulating at the liner top.
	Cement plug	Verified as indicated in Table B.5.	Cement	— If multiple cement plugs are installed, only the shallowest cement plug requires pressure and inflow testing. Subsequent plugs should be weight-tested rather than pressure tested. — A cement basket or thick gel pill may be used to provide a base for a cement plug to enhance the quality of the resulting plug.
	Bridge plug or cement retainer	Pressure test upon installation.	Mechanical	Set and tested below balanced cement plug. If the shoe is drilled out then a bridge plug/retainer shall be run as shown in Figure A.3.1.
	Casing	Pressure test before drillout.	Mechanical	
	Drilling fluid	Mud checks confirm density.	Hydrostatic	— Unable to maintain density after rig moves off of well. Weight material may settle out of mud or sag to the low side of the well. — Consider riser margin loss when designing the density to be left in the well. — Ensure that corrosion inhibitor and/or oxygen scavenger is added to fluid left in well if well is to be re-entered.

Casing Configuration/Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Inside casing *(continued)*	Cement plug (surface)	Placement is verified by displacement volumes.	Cement	Does not require pressure or inflow test.
Outside casing – Long-string	Cement behind casing	— Verified as indicated in Table B.3. — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to qualitatively assess the cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation. — If no hydrocarbon reservoir is present in the annulus, the annular cement is not verified.
	Casing hanger seal assembly	— Pressure test upon installation — Inflow test	Mechanical	— The seal assembly running tool may also provide an operational indication that the assembly is engaged to the proper location within the wellhead housing. — Prior to final abandonment, conduct inflow test to the maximum hydrostatic differential expected (e.g., marine drilling riser margin loss or greater). Consider running in conjunction with inner-casing barrier inflow test.
Outside Casing - Liner	Cement behind liner	— Verified as indicated in Table B.3 — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to qualitatively assess the cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation. — If no hydrocarbon reservoir is in annulus, verification can be a formation integrity test.



Key

1	casing to casing annuli	5	BOP stack	9	lining to casing annulus
2	work string	6	mudline	10	circulating valve
3	work string to casing annulus	7	casing hanger seals	11	released packer (not sealing)
4	stab-in FOSV	8	liner hanger packer	12	sump packer

Yellow shading indicates drilling mud or completion fluid.

NOTE 1 A flowpath inside the work string would encounter the following barriers: completion fluid (hydrostatic barrier only if overbalanced), work string, and stab-in FOSV or internal BOP. Operationally, influx detection, recognition, and response occur inside the work string.

NOTE 2 A flowpath inside the work string-to-casing annulus would encounter the following barriers: completion fluid (hydrostatic barrier only if overbalanced), casing, and BOP. Operationally, influx detection, recognition, and response occur for the work string to casing annulus.

NOTE 3 A flowpath up the liner and casing annuli to the mudline would encounter the following barriers: liner cement, liner, liner hanger seal, casing cement, outer casing and cement, and wellhead hanger seal.

Figure A.4: Tripping After Tubing-Conveyed Perforating

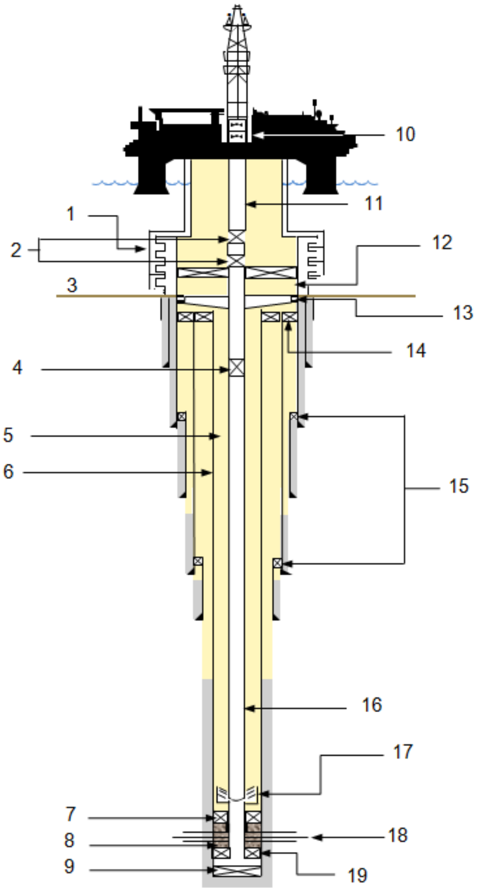
See Table A.4 for a more detailed description of the barriers available for this operation.

Table A.4: Tripping After Tubing-Conveyed Perforating

Casing Configuration /Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Inside work string	Completion fluid	Fluid checks confirm density.	Hydrostatic	— Adjust fluid density as needed. — Review resevior pressure data to ensure completion fluid weight provides adequate overbalance pressure for the perforated zone.
	FOSV or internal BOP (Kelly valve)	— Pressure test with BOPs. — Stab-in drills performed to assess operational readiness.	Mechanical, requires operational barrier	— FOSV can be installed on a drillpipe connection at the rig floor and then closed. Top drive may have internal BOP. — Ensure thread compatibility or cross-overs to the drillpipe. — Minimizing the time required to install the FOSV is critical.
	Work string	Periodic inspection of tube body and threads; not typically tested.	Mechanical	
	If actuated, BOP BSRs are designed to seal above the drillpipe that they shear	Sealing capability of BSR is tested. The BOP's capability to shear and subsequently seal is not routinely tested.	Mechanical, requires operational barrier	— Part of the completion assembly (e.g., the perforating guns) may not be shearable. — Capability to shear and subsequently seal is not routinely tested. — Good practice to position drill string so tool joint is not across shear rams during well control response. — Not all shear rams are designed to seal.
Inside casing	Completion fluid	Fluid checks confirm density.	Hydrostatic	Adjust fluid density as needed, monitor hole volume during trips using trip tank.
	Casing	Pressure test upon installation.	Mechanical	
	Work string	Not typically tested.	Mechanical	
	Wellhead	Pressure test upon installation of surface casing.	Mechanical	Include testing of ring gasket between wellhead and BOP stack.

Casing Configuration /Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Inside casing *(continued)*	BOP	Pressure test upon installation and periodically thereafter.	Mechanical, requires operational barrier	— Actuation and proper functioning required to close BOP. — Consider risk of tripping spent guns past BOP. (BOPs will not seal around spent guns). — Crew recognition and crew response are operational barriers involving training and periodic drills. — C/K line system is considered part of the BOP system. An operational barrier is the periodic circulation of drilling fluid through the C/K lines to ensure they are not plugged.
	Influx detection	Periodic function check of equipment.	Operational – Rig equipment	Trip tank; flow-show; pit volume totalizer; and driller flow check.
	Influx recognition and response	Periodic drill, certification.	Operational – Personnel	Well control training, certification, and drills.
Outside casing – Long-string configuration	Production casing cement	— Verified as shown in Table B.3. — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to qualitatively assess the cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.
	Casing	Pressure test upon installation	Mechanical	
	Casing hanger seal	— Pressure test upon installation. — Inflow test may be performed for production casing hanger.	Mechanical	— The seal assembly running tool may also provide an operational indication that the assembly is engaged to the proper location within the wellhead housing. — Lock down that prevents seal movement required on production casing hanger when hanger movement is possible.
Outside casing and liner – Liner configuration	Cement behind liner	— FIT after drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify cement placement success.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.

Casing Configuration /Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Outside casing and liner – Liner configuration *(continued)*	Liner top or lap seal	— Pressure test — Proper installation — Monitor cement job placement parameters	Mechanical or cement	— A dedicated liner-top packer represents a mechanical barrier. — The overlapping casing-by-liner annulus can be sealed with set cement. — Consider inflow test for a production liner. — Placement parameters for liners include looking for cement after disconnecting from the liner and circulating at the liner top.
	Cement behind previous casing	— FIT after drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify cement placement success.	Cement	— Test of previous shoe verifies flow from liner annulus will not enter previous casing annulus. — Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.



Key

1	BOP stack	6	production casing	11	landing string	16	tubing
2	SSTT (details in Figure 11.1)	7	packer	12	pipe rams	17	PBR seals
3	mudline	8	gravel pack sand	13	tubing hanger (if run)	18	perforations
4	SCSSV	9	retainer	14	casing hanger seal	19	sump packer
5	tubing/casing annulus	10	stab-in FOSV	15	liner hanger packers		

Yellow shading indicates drilling mud or completion fluid.

NOTE 1 A flowpath inside the tubing would encounter the following barriers: tubing string, SCSSV (if closed), SSTT (if closed), surface test tree (if closed), and valves in choke manifold (if closed). Note that the operation being described is intended to flow through this path, while a series of valves is available to shut-in the flow if necessary.

NOTE 2 A flowpath inside the tubing to casing annulus would encounter the following barriers: packer or PBR seals, completion fluid (hydrostatic barrier only if overbalanced), casing and tubing, tubing hanger seals, and BOP rams closed on the SSTT.

NOTE 3 A flowpath up the liner and casing annuli would encounter the following barriers: production casing cement, liner cement, liner, liner hanger seal, casing cement, production casing, intermediate casing and cement, and wellhead hanger seal.

Figure A.5: Flowback through Production Tubing to Rig

See Table A.5 for a more detailed description of the barriers available for this operation.

Table A.5 Flowback through Production Tubing to Rig

Casing Configuration/ Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Inside tubing	Tubing	Pressure test upon installation	Mechanical	Multiple sliding sleeves can be run opened or closed mechanically depending on the operation.
	SCSSV (if closed)	SCSSVs are tested during manufacture and in the shop, not upon installation.	Mechanical	— Self-equalizing SCSSV designs allow pressure on both sides of the valve. — Ensure annulus pressure during operation is not sufficient to hold SCSSV open if control line leaks.
	SSTT (if closed)	SSTT valves are tested during manufacture and in the shop, not upon installation. The SSTT body can be tested with the tubing.	Mechanical	Default position on the subsea test tree is closed position, which can be held if emergency disconnect is enacted and tree is split.
	Surface test tree (if closed)	Surface test trees are typically tested during manufacture and in the shop. May be tested upon installation.	Mechanical	Surface test trees typically include alternative flowpaths and redundancy of valves to enhance reliability.
	Choke manifold valves (if closed)	Pressure tested with BOPs.	Mechanical	Choke manifolds typically include alternative flowpaths and redundancy of valves to enhance reliability.
Tubing/casing annulus	— Gravel-pack packer (used only with certain completions) — Packer — PBR	Pressure test upon installation.	Mechanical	— An isolation packer may or may not be run in addition to a gravel-pack packer. — Packer seals are generally the limiting factor for pressure tests.
	Completion fluid (if overbalanced to the formation pore pressure)	Completion fluid density verified before pumping.	Hydrostatic	— Adjust completion fluid density as needed. — Brines are not typically affected by “sag” of weighting material. — Account for effects of downhole temperature on density.
	Casing	Pressure test upon installation.	Mechanical	
	Tubing hanger	Pressure test upon installation.	Mechanical	

Casing Configuration/ Flow Path	Barriers (Bottom to Top)	Example Confirmation Methods	Type	Special Considerations
Tubing/casing annulus *(continued)*	BOP	Pressure test upon installation and before flow test.	Mechanical, requires operational barrier	— During typical flowback operations a BOP element is closed on the SSTT to anchor the assembly. If flow was detected, it might be possible to close the BSRs or the annular to keep the flow out of the riser. (Good practice to space out above SSTT so tool joint is not across shear rams). — Watch circles for dynamically positioned rigs may be smaller for well flowback operations.
Outside casing – Long-string configuration	Production casing cement	— Verified as described in Table B.3. — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify the extent of cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.
	Production casing	— Pressure test upon installation	Mechanical	
	Casing/Liner(Intermediate /outer)	Presure test upon installation	Mechanical Cement	Consider APB. Use of rupture disks as a mitigation will remove an external barrier. They shall not be exposed to hydrocarbon zones. Refer to section 8.15.4.
	Cement for intermediate casing/liner	— Verified as described in Table B.3. — FIT upon drillout. — Monitor cement job placement parameters. — Cement evaluation log techniques can be used to identify the extent of cement placement.	Cement	— Evaluation of FIT results includes the shape of the curve of pressure versus time and not simply the maximum pressure. — Some placement parameters measured during job include lift pressure and returns. — Cement evaluation logs are qualitative and subject to interpretation.

Annex B

(Informative)

Examples Barrier Definitions

The tables included in Annex B represent example descriptions of well barriers used during the drilling, completion, operation, and abandonment of DW wells. The tables list considerations associated with the selection and use of the well barriers.

Annex B is not intended to capture every possible type of barrier or to describe every consideration relevant to using the barriers that are included. The design and use considerations, suggested verification methods, and suggested approach to re-establishing the barrier do not preclude other alternatives.

The following well barriers are described in this Annex:

- B.1: Hydrostatic Fluid
- B.2: Casing
- B.3: Cement Behind Casing or Liner
- B.4: Shoetrack
- B.5: Cement Plugs
- B.6: Subsea Wellhead
- B.7: Subsea BOP System
- B.8: Subsea Tree
- B.9: Production Tubing String
- B.10: Production Packer
- B.11: Surface-Controlled Subsurface Safety Valve (SCSSV)
- B.12: Vertical Tree Tubing Hanger Plug
- B.13: Horizontal Tree Crown Plug

Table B.1: Hydrostatic Fluid

	Definition	Special Considerations	Relevant Standards
Description	Fluid in the well	Mud, brine, or water typically circulated during drilling or completion operations.	— API RP 13B-1 — API RP 13B-2
Design considerations	To consider hydrostatic pressure as a barrier, it shall exceed the pore pressure of exposed formation zones, including a design margin.	— Hydrostatic pressure is the normal pressure exerted by a continuous column of fluid, caused by gravity exerted on the fluid. — Dynamic effects from pipe movement can change the pressure exerted by the fluid on the formation. — Temperature, solids settling, and compressibility affect the density of a fluid and thus the pressure it exerts on the formation. — Consider a trip margin.	
Barrier confirmation	— Confirm density and other key fluid properties before circulating the fluid into the wellbore and monitored by periodic checks as dictated by the application. — Fluid level should be continuously monitored during well operations.	— Check the density of fluid coming out of the well during any circulation operation and compare to the density of the fluid going into the well. Any reduction in the density shall be assessed. — Mud viscosity affects the magnitude of surge and swab effects arising from pipe movement, and the salinity of the water phase affects hydrate formation. — During drilling operations, the daily or tourly mud check reconfirms the key fluid properties.	
Barrier use	— Fluid level should be continuously monitored during well operations. — Fluid inflow and outflow should be continuously monitored during well operations. — Fluid suspensions (e.g., mud) should be checked and maintained periodically (daily or tourly) during well operations.	— Adequate materials and liquid volumes should be available to maintain the proper density. — Fluid level can be confirmed via flowline returns. If there are no returns during circulation attempts, alternative means to confirm fluid level should be implemented. — A fluid loss rate that is acceptable should be defined during well planning. Note: during displacement operations, pit volumes shall be monitored	

	Definition	Special Considerations	Relevant Standards
Barrier failure	The hydrostatic fluid barrier has failed if hydrostatic pressure of the fluid is less than formation pressure.	Failure may be triggered by the following: — Pore pressure is higher than anticipated; — Fluid density is reduced due to loss of suspended solids or influx of gas; — Height of fluid column is reduced due to lost returns or failure to maintain fluid level during tripping out of hole; — Dynamic effects of pipe movement (swab); — Loss of ability of cement to transmit hydrostatic pressure as it sets. Note: In a producing well, the packer fluid density might be overbalanced at the depth of the formation; however, at a shallower depth, the tubing pressure might be higher.	
Barrier re-establishment	Adjust the density in the hydrostatic fluid column to re-establish fluid pressure so that it is greater than the formation pressure.	— If an influx is detected, invoke well control response and increase the fluid density throughout the well. — If the fluid level cannot be maintained, consider reducing the fluid density to regain circulation. — If it is not possible to maintain circulation and well control, consider installing a casing barrier.	

Table B.2: Casing

	Definition	Special Considerations	Relevant Standards
Description	Tubular installed and cemented in the well	Typically made from steel, with threaded connection every ~40 ft (~12 m)	— API SPEC 5CT
Design considerations	Casing strings should be designed to withstand all loads and environments anticipated throughout the life cycle of the well.	— Include burst, collapse, axial loads, and triaxial stress calculation. — Loads in DW wells include the potential for annulus pressure buildup if the annulus is trapped. — Consider bending and fatigue loads when designing structural and surface casing strings. — Consider wall loss from corrosion or wear when determining the capacity of the casing. — Consider the performance of the connections used to assemble the casing string.	— API SPEC 5CT — API TR 5C3 — API RP 5C5
Barrier confirmation	Pressure test the casing string upon installation, before drilling out, or beginning completion operations.	— Consider anticipated loads when determining the test pressure. — Acceptance criteria (e.g., loads, hold time, pressure stability) are sometimes dictated by regulatory requirements. — Changing temperature conditions continually affect density of the fluid.	
Barrier use	— Consider changes in design premise that may impact tubular barrier (loads, changes in fluids such as H_2S). — Periodic reverification of the casing barrier may be required as conditions change (e.g., wear during drilling operations, corrosion, greater design loads).	— Consider evaluating casing at periodic intervals during ongoing operations (i.e., every 30 days while drilling) or when re-entering the well. — Evaluation log techniques (including mechanical, electromagnetic, and ultrasonic) may assess the extent of tubular degradation due to wear or corrosion. — Consider the effect of reduced wall thickness designing the casing, and consider measures to reduce wear or to quantify the loss. — The use of a ditch magnet to collect and weigh metal shavings can be used as a qualitative indicator of casing wear.	

	Definition	Special Considerations	Relevant Standards
Barrier failure	The casing barrier has failed if the hydrostatic pressure test acceptance criteria are not met or there is other evidence of an integrity loss during normal operations or during the periodic casing re-evalution.	Failure can be triggered by: — Connection leak; — Damage to pipe body caused by wear, corrosion, or manufacturing defect; — Application of a service load that exceeds the tubular capacity.	— API RP 90
Barrier re-establishment	Verify that any repair of a tubular barrier is successful with a pressure integrity test.	A tubular can be repaired by installing a patch across the location of lost integrity, by squeezing cement or other materials at the location of the integrity loss, or by installing additional casing.	

Table B.3: Cement Behind Casing or Liner

	Definition	Special Considerations	Relevant Standards
Description	Set cement located between openhole and casing/liner or between two concentric strings of casing/liner	— The cement should be qualified with laboratory testing and QA/QC measures using field representative material. — Blends with other materials can be used to give required slurry properties and set mechanical properties.	— API Spec 10A — ASTM C-150
Design considerations	— Develop a cement job placement design that considers specific well conditions (e.g., pore and fracture pressure gradients, estimated hole volumes, drilling fluid density, target cement placement height). — Develop a cement job placement plan that includes a pre-job circuation plan, mechanical separation of fluids, and pipe movement, and a displacement plan that addresses rates and volumes. — All fluids (e.g., mud, spacer, cement) must be designed to maximize mud displacement and cement placement efficiency. Considerations include rheological and density hierarchy as well as ECDs and their effect on well control. — Design slurry properties (e.g., fluid loss control, thickening time, compressive strength, rheology, etc.) to maintain well control during placement, transition, and final set. — Slurry properties must be confirmed by lab testing using representative temperatures and pressure schedules. — Use industry practices to perform slurry testing. Modifications to meet specific well conditions are permitted.	— Job placement can be modeled using computer simulations that can incorporate u-tube analysis, mud removal, centralization, pipe movement, and fluids design. — Slurries with specialized additives or cement blends address specific well challenges such as long permeable intervals, flow hazards, lost circulation zones, tight annular clearances, and reservoir characteristics. Various regulatory or company requirements specify the necessary length of cement in an annulus to obtain a barrier seal. — Spacers must be designed using field representative samples. — Address fluid compressibility in the displacement plan when using non-aqueous fluids. — Contingency plans should address issues such as slow flowback, float equipment failure, dart failure, liner hanger or seal failure, and surface equipment failure.	— API RP 65 — API RP 65-2 — API RP 10B-2 — API RP 10B-3 — API RP 10B-4 — API RP 10B-5 — ISO 10426-5 — API RP10D-2 — ISO 10427-2 — API TR 10TR-4

	Definition	**Special Considerations**	**Relevant Standards**
Barrier confirmation	Proper execution highlighting the following: — Fluid returns are as expected; — Placement pressures follow predicted pressures and indicate proper lift pressure; — Density control and additive (e.g., liquid) addition are properly maintained; — No flow observed after releasing the displacement pressure; — Compare post-job simulation estimate of cement top and placement efficiency to pre-job targets; — The cement after placement remains undisturbed and no flow occurs while waiting on cement (WOC); — WOC time associated with the cement achieving a compressive strength target (such as 50 psi); — Successful shoe test (FIT or leakoff test) if the shoetrack is drilled out.	— Proper execution can be evaluated using the cementing matrix in API RP 65-2. — Spacer properties can be confirmed by the mud engineer in the field. — Effects of contamination on fluid properties must be addressed (e.g., rheology, thicking times, and compressive strength development). — Care should be taken when interpreting placement pressure data and job simulations as they may not provide an accurate position of the cement in the well. — Compressive strength continues to develop following the cement slurry's initial set and the first "time to 50 psi" reading is not an artifact of the initial temperature and pressure ramp used in the testing. — Consider using cement evaluation logs to verify cement top and sufficient isolation when surface execution data indicates questionable cement placement. Note: Cement evaluation logs have limitations and rely on subjective interpretation. An interval with a log response that appears to indicate good isolation may not be isolated, and one with a log response indicating lack of isolation may be isolated.	— API TR 10TR-1
Barrier use	— For well control, WOC until the cement achieves sufficient compressive strength (e.g., 50 psi). For pressure testing or drillout, WOC until the cement achieves sufficient compressive strength (e.g. 500 psi) and meets regulatory requirements. — For completion and production, WOC until cement properties are sufficient for the anticipated stress.	Do not disturb the cement until sufficient compressive strength is achieved.	
Barrier failure	Indications of cement failure include: — Formation integrity test/leakoff test (FIT/LOT) results are less than anticipated values; — Lost circulation during or after placement; — Annular flow observed after placement; — Annulus pressure increase over time in excess of thermal expansion.	— Another potential cause of a low FIT/LOT result is the formation itself. — If lost circulation does not prevent cement from covering a potential flow zone, then it is not a concern. — Refer to RP 90 for the evaluation of sustained casing pressure.	— API RP 90
Barrier re-establishment	Consider re-establishing the cement barrier by remedial operations such as squeezing cement or other sealing materials into the annulus.	Requires re-verification to consider as a barrier.	

Table B.4: Shoetrack

	Definition	Special Considerations	Relevant Standards
Description	Combination of the set cement and float equipment found between the landing collar and the casing shoe.		
Design considerations	The shoetrack functions as a single barrier. Initially the float valves prevent flowback of the cement after the cement job. Once the cement sets, the cement within the shoetrack is the barrier isolating the casing from formation pressures.	— The shoetrack should allow sufficient volume to contain the wiped mud film ahead of the wiper plug and allow for set cement of sufficient strength to provide a pressure barrier. Factors affecting the shoetrack volume include total displacement volume, number and type of wiper plugs, casing string geometry, and fluid type. — The reliability of the shoetrack system can be increased through the use of multiple float valves, multiple wiper plugs, and increased volume between the casing shoe and landing collar. — The shoetrack is considered a cement barrier. When hydrocarbons are present, a verified shoetrack capable of holding reservior pressure loads and fluids without cement may be considered a mechanical barrier. The ability of the shoetrack to seal after cementing must be validated for the production pressure differentials prior to initial use.	— API RP 10F — API RP 65-2
	Float valves shall be designed to withstand the flow rates and volumes of the fluids pumped during circulation and cementing of the casing string.	Refer to API RP 10F for determining service class corresponding to anticipated service requirements. Float valves are typically designed for liquid service (mud and cement).	
	Float valves shall be designed to withstand the differential pressure between the minimum anticipated hydrostatic column above the shoetrack and the maximum hydrostatic column in the casing annulus.	Consider the inflow load on the shoetrack from the reduced hydrostatic column due to mud displacement when used as an abandonment barrier.	
	Float valves can be configured to allow the casing to fill automatically while run into the hole, thereby reducing the surge pressure exerted on the wellbore. If configured, these auto-fill devices must be deactivated prior to beginning cementing operations.	— The impact of auto-fill tools on well control while running casing and the procedures for auto-fill conversion must be thoroughly understood. — Lost circulation material may be trapped in the valve and prevent it from converting. — It may be difficult to assess if the auto-fill floats have successfully converted as pressure spikes may be hard to interpret. Surge pressures, bouyancy, and mud pressure differentials may help validate conversion. — Contingency procedures should be prepared in case the auto-fill system does not deactivate.	
	Ensure the float or landing collar has suffficient load capacity for the casing test pressure.	— Verify compatibility between plugs and float/landing collars. — Float collar valves are not designed to provide a gas-tight seal.	

	Definition	Special Considerations	Relevant Standards
Barrier confirmation	— A successful casing test before drill-out is a positive test of the shoetrack. — If the shoetrack is intended as an abandonment barrier, perform a inflow test to a pressure equal or greater to maximum anticipated differential pressure	— Checking for "no flow" by releasing the displacement pressure after the end of the displacement provides an inflow pressure limited to the hydrostatic imbalance at the shoe (i.e., u-tube pressure from annulus). — If the floats do not hold upon release of the displacement pressure, the final displacement pressure should be reapplied and held while the cement sets. — "No flow" observed after release of the displacement pressure after the end of displacement may confirm that the float equipment functioned properly. It does not confirm that the cement has set in the shoetrack or that the shoetrack system is a verified barrier.	
Barrier use	After the casing is cemented, keep the casing full of fluid and monitor the fluid level for any indication of flow back or losses during all subsequent operations (including cased hole operations).		
Barrier failure	The shoetrack barrier has failed if either of the barrier confirmation tests have failed or they are not performed, or there is other evidence of an integrity loss.		
Barrier re-establishment	— The shoe can be squeezed with cement. Required barrier confirmation tests shall be re-performed. — A mechanical bridge plug can be installed and validated as above to replace the shoetrack as a barrier.	Consider the well application when evaluating the appropriate bridge plug design.	

Table B.5: Cement Plugs

	Definition	Special Considerations	Relevant Standards
Description	Set cement located in openhole or inside casing/liner to prevent formation fluid flow between zones or flow up the wellbore.	Make sure that the cement supply is a suitable type of cement for use in well cementing. The cement may be consistent with published specifications or it may be other cements that have been qualified with laboratory testing and QA/QC measures. Blends with other materials can be used to give required slurry properties and set mechanical properties.	— API SPEC 10A — ASTM C150
Design considerations	— Develop a cement job placement design that considers specific well conditions (pore and fracture pressure gradients, estimated hole volumes, drilling fluid density, target plug height). — Design slurry properties (fluid loss control, thickening time, compressive strength, rheology) to maintain well control during placement, transition, and final set. — Use industry practices to perform slurry testing. — Implement appropriate plug placement practices when possible such as establishing a base for the plug, rotating the pipe, selecting an appropriate stinger size, underdisplacing and designing a spacer volume and properties for mud removal.	Setting a cement plug above a mechanical plug such as a bridge plug or retainer increasing te chance of obtaining a barrier.	— API RP 65 — API RP 65-Part 2 — API RP 10B-2 — API RP 10B-3 — API RP 10B-4 — API RP 10B-5 — API RP 10D-2 — API TR 10TR-4
Barrier confirmation	Proper execution highlighting the following: — Fluid returns are as expected. — Placement pressures follow predicted pressures. — Density control and additive addition (e.g., liquid) are properly maintained. — Compare post job simulation estimate of cement top to pre-job target. — Pipe pulls dry as expected after the plug is placed.	Care should be taken when interpreting placement pressure data and job simulations as they may not provide an accurate position of the cement in the well	

	Definition	Special Considerations	Relevant Standards
Barrier confirmation (*continued*)	— Monitor wellbore fluid levels after placement for signs of inflow. — Openhole Plug: weight test cement after sufficient WOC time.		
	Inner-Casing Plug: — Slack-off weight to confirm location and cement set — Pressure test	If a mechanical plug is installed below the cement plug, a pressure test is not definitive and the slack-off confirmation is preferred.	
	Inner-Casing Abandonment/ Evacuation Plug: — Pressure test — Inflow test	When planning an inflow test, consider the maximum hydrostatic differential expected for all well operations that affect the cement plug.	
Barrier use	— Avoid pressure testing of casing or other pressure fluctuations during cement transition time. — Allow proper cement setting time before continuing operations.		
Barrier failure	Cement failure is possible if: — Slurry is contaminated because no support base is used to reduce slumping of slurry or fluid swapping. — Soft cement is tagged.	"Soft" cement is commonly tagged at the top of the plug because of contamination. Establish an acceptance criterion *(e.g., find hard cement no deeper than 1/3 of the way into the planned plug length)*.	
Barrier re-establishment	Additional or replacement plugs or barriers are required in the event of a cement plug failure.		

Table B.6: Subsea Wellhead

	Definition	Special Considerations	Relevant Standards
Description	Pressure containing and load-bearing element with casing/tubing hangers landed inside - each with an annular seal assembly installed	Typically manufactured from alloy steel with a top profile and sealing area to accept the BOP/wellhead connector, and a surface casing string (typically ~ 20- to 22-in.) is attached on bottom. Internal bore has provisions to land and seal multiple casing hangers and seal assemblies.	— API Spec 17D
Design considerations	Design wellhead to withstand mechanical/pressure loads and environments anticipated throughout the life cycle of the well.	Design guidelines provided in API Spec 17D and ASME boiler and pressure vessel codes. In addition, all anticipated mechanical loading from external sources must be included in design considerations.	— API Spec 17D — ASME Boiler & Pressure Vessel Codes — API TR 17TR-3
Barrier confirmation	Wellhead housing is hydro-tested to 1.5 times maximum working pressure during manufacturing. The subsea wellhead is pressure tested upon installation with the surface casing.	— Define the test pressure based on anticipated loads or as dictated by regulatory requirements. — Acceptance criteria (e.g., hold time, pressure stability) may be dictated by regulatory requirements. — The entire wellhead housing is not typically tested to its working pressure upon installation. If a BOP test plug is landed in the wellhead housing, then the part of the housing above the plug and the connection to the BOP are tested. Otherwise, the housing will be tested to the surface casing test pressure.	— API SPEC 17D
Barrier use	The continuing integrity of the subsea wellhead is assessed by repeated testing.	Conduct tests each time a new string of casing or tubing is installed and when re-establishing the BOP stack. If desired, additional tests can be obtained during routine BOP stack tests by using a seal within the casing rather than a test ram.	
Barrier failure	The wellhead system barrier has failed if the casing hanger/seal assembly gasket test fails to meet acceptance criteria or there is other evidence of integrity loss.	Failure may be triggered by the following: — Damage and/or movement of the annulus seal element; — Damage/washout of wellhead gasket prep; — Damage to ID of wellhead housing seal area or areas; — Damage to casing hanger/seal area/casing.	
Barrier re-establishment	— If possible, re-install the seal assembly or a new seal assembly after a cleanout run. — Verification that any repair or replacement of seals/seal areas/wellhead gaskets was successful via a positive pressure integrity test.	The subsea wellhead may be repaired by installing multiple variations of emergency or contingency seals and wellhead gaskets.	

Table B.7: Subsea Blowout Prevention Equipment

	Definition	Special Considerations	Relevant Standards
Description	System of hardware installed at the mudline above the subsea wellhead that is capable of sealing the open wellbore, sealing around some tubulars in the wellbore, and shearing some tubulars in the wellbore, subsequently sealing. Includes high pressure C/K lines, C/K valves, and a choke manifold at the surface on the rig. Also includes control system.	To function as a physical barrier, the BOP system must be actuated by control from the rig floor (or by automated fail-closed logic). This actuation step represents an operational barrier.	— API SPEC 16A — API SPEC 16D — API RP 53 — API RP 59
Design considerations	— The BOP equipment shall be designed and constructed to contain the pressures expected during well control operations. — The BSR capability shall be demonstrated and known before beginning drilling operations.	— Various regulatory and company standards define minimum BOP configurations. — BOPs typically include one or more ram BOPs (e.g., pipe rams, variable bore rams, test rams, BSRs, or shear rams) and one or more annular BOPs. Annular BOPs may be rated to a lower pressure than the ram BOPs because they are designed to seal on a wide range of equipment sizes. Ram BOPs may have a higher pressure rating than annular BOPs, but may have limitations on the pipe size range they can close on, or the hangoff capacity. BSRs also have capacity limits.	
Barrier confirmation	The BOP shall be function- and pressure-tested upon installation on the wellhead. The BOP elements shall be periodically tested thereafter.	— Define the test pressure based on anticipated loads or as dictated by regulatory requirements. — Acceptance criteria (e.g., hold time, pressure stability) may be dictated by regulatory requirements. — In addition to testing upon installation, consider stump testing the BOP system to the MASP for the well before initially running and latching the stack to the subsea wellhead. — Consider function testing secondary control systems (e.g., deadman, autoshear, acoustic, ROV function) prior to deployment.	

	Definition	Special Considerations	Relevant Standards
Barrier use	— The BOP system is actuated when there is evidence of a fluid influx into the well. — A BOP seal element can be closed as a precaution during the removal of other barriers from the well.	— Actuation and proper functioning are required to close the BOP. — Timely actuation of the BOP in a well control event also requires the detection of an influx and recognition and response (i.e., actuation of the BOP). Detection is an operational barrier that combines measurement systems requiring calibration and maintenance (e.g., trip tank), with practices such as the driller flow check. Crew recognition and crew response are operational barriers involving training and periodic drills. — If the BSR(s) are used to shear pipe, consider inspecting and pressure-testing BSRs before resuming normal operations.	
Barrier failure	The BOP equipment has failed if not able to seal test pressure or well pressure when it is closed or if unable to close from a particular actuation location.	BOP systems have redundancy, such that the loss of a single function might not require suspension of operations; however, the operator and drilling contractor should discuss this at appropriate levels.	
Barrier re-establishment	— Verify system components individually and retest to confirm that the failure has been corrected. — If necessary, secure the well according to the guidance in Annex A.2 or A.3 and retrieve the BOP to the rig for repairs.	On some BOP systems, service or repair of the primary control systems requires pulling the riser; however, some systems allow the control pod to be retrieved alone.	

Table B.8: Subsea Production Tree

	Definition	Special Considerations	Relevant Standards
Description	Pressure containing and load-bearing element located on the mudline with bores that are fitted with production and annulus master, wing valves, and swab valves in a vertical tree configuration. Lower end of the assembly has a connector to attach tree to wellhead and upper end has a closure cap.	— Typically manufactured from alloy steel with cladding in seal areas. Production and annulus bores in subsea production tree contain valves to allow hydrocarbon flow to be controlled. Bores provide vertical access for passing plugs and performing workover operations. — Swab valves are not available for horizontal trees.	— API SPEC 17D — API SPEC 6A
Design considerations	Should be designed to: — Withstand all loads and environments anticipated throughout the life cycle of the well, including production, completion, and workover loads. — Provide a flow conduit for hydrocarbons from the tubing into the subsea-to-surface lines with the ability to stop the flow by closing the wing valve and/or master valve. — Provide monitoring and pressure adjustment of the “A” annulus. — Provide a seal to the wellhead high pressure housing.	Design guidelines are provided in API Spec 17D and ASME Boiler and Pressure Vessel Codes. Additionally, consider possible mechanical loading from external sources, such as snag and pull-in loads and loads from workover operations.	— API SPEC 17D — ASME Boiler and Pressure Vessel Codes
Barrier confirmation	Subsea tree body is hydro-tested to 1.5 times maximum working pressure during manufacturing .The subsea tree may be pressure tested upon installation, onshore, or on a vessel prior to installation.	— Define the test pressure based on anticipated loads or as directed by regulators. — Acceptance criteria (e.g., hold time, pressure stability) may be directed by regulators.	
Barrier use	The continuing integrity of the subsea tree can be assessed by repeated testing. The principal valves in the tree are the acting barriers.	Conduct tests at periodic intervals as directed by regulators or the operator. Test frequency can be incrementally decreased as consecutive qualified/ successful tests have been performed.	
Barrier failure	The subsea production tree barrier has failed if the pressure test fails to meet acceptance criteria or there is other evidence of an integrity loss.	Failure can be triggered by: — Damage or washout of a valve — Damage or washout of a wellhead gasket seal — Damage or washout of a plug/seat — Other	
Barrier re-establishment	Verify successful repair or replacement of tree components (e.g., valves, seals, or other parts) through a pressure integrity test.	Subsea tree barrier repair (e.g., valves, seals, etc.) usually requires retrieval of the tree to surface.	

Table B.9: Production Tubing String

	Definition	Special Considerations	Relevant Standards
Description	Final tubular installed in the wellbore; used as the flow path for all fluid and gas produced from the reservoir to the wellhead.	Typically made with coupled joints of tubular steel landed at the wellhead and set downhole in a polished-bore receptacle or a packer.	
Design considerations	Tubing strings should be designed to withstand all loads and environments anticipated throughout the life cycle of the well, including production, completion, and workover loads and associated corrosion.	— Include burst, collapse, axial loads, and triaxial stress calculation. — Consider axial load changes due to temperature changes and buckling. — Annulus pressure buildup is a specific consideration for tubing design in subsea wells. — Consider the performance of connections used to assemble the tubing string.	— API SPEC 5CT — API TR 5C3 — API RP 5C5
Barrier confirmation	Pressure test the tubing string after installation.	— Consider anticipated loads when determining the test pressure. — Acceptance criteria (e.g., loads,hold time, pressure stability) are sometimes dictated by regulatory requirements. Changing temperature conditions continually affect density of the fluid. — Consider the effects of the pressure test on PBR seals, if present.	
Barrier use	Onging use of this barrier requires monitoring of its backside pressure to detect any communication.	— Consider establishing alarms on the production sensor data monitoring system that indicate potential integrity issues. — Consider the effect of reduced wall thickness when planning any well maintenance or workover whose operation can cause tubular wear. Consider measures to reduce wear or to quantify the loss and its detriment. — Consider re-testing tubing when re-entering the well. — Evaluation log techniques (including mechanical, electromagnetic, and ultrasonic) may assess the extent of tubular degradation due to wear or corrosion.	

	Definition	**Special Considerations**	**Relevant Standards**
Barrier failure	The tubing barrier has failed if the hydrostatic pressure test acceptance criteria are not met or there is other evidence of communication with the annulus.	Failure examples and causes include: — Connection leak; — Insufficient engagement with PBR ; — Damage to pipe body caused by wear, corrosion, or manufacturing defect; — Application of a service load exceeding capacity.	— API RP 90
Barrier re-establishment	Repair or replace the tubing. Pressure test the repaired or replaced tubing after installation.	— If tubing is not intended as a pressure-holding barrier and is merely a flow path, pressure testing is not required. — A well can still function as a system of barriers if a tubing leak occurs. Assess the need for pressure isolation at the time of the leak.	

Table B.10: Production Packer

	Definition	Special Considerations	Relevant Standards
Description	A completion component to which the production tubing string attaches. When deployed, it provides a seal between the outside of the production tubing and the inside of the casing or liner for the well's life cycle.	Normally run near the lower end of the production tubing	

Design considerations	Production packers should be designed to withstand all loads and environments anticipated throughout the life cycle of the well, including production, completion, and service loads and associated corrosion.	— Include tension, compression, and differential pressure loads.
		— Include the metallurgy of flow-wetted surfaces and elastomer selecion for the installation and well envionment.
		— Consider the effects of temperature.
		— Feed-through packoffs sometimes included for access to hydraulic or electrical functions below packer.
		— Potential leak path in setting mechanism.
		— Casing wear and uncemented casing are both detrimental to packer performance.
		— Packer engagement to the casing exerts hoop stress on the casing:
		  — Set packer away from a casing connection if possible.
		  — Cement outside the casing increases the casing's ability to withstand hoop stress.
			— ISO 14310
			— API SPEC 11D1

Barrier confirmation	— Normal practice is a test from above by pressurization of tubing by casing annulus. — Packer can be tested from below upon installation in some situations (e.g., an unperforated completion).	— Consider anticipated loads when determining the test pressure. — Acceptance criteria (e.g., loads, hold time, pressure stability) are sometimes dictated by regulatory requirements.	
Barrier use	Monitor tubing by casing annulus pressure	Consider establishing alarms on the production sensor data monitoring system that indicate potential integrity issues.	
Barrier failure	The production casing barrier has failed if the pressure test acceptance criteria are not met or there is other evidence of communication in the "A" annulus.	Diagnostics can sometimes differentiate between packer leakage and other causes of annulus pressure.	
Barrier re-establishment	A major intervention is normally required to replace a failed production packer	The failed packer does not always need to be removed; another packer may be installed above it.	

Table B.11: Surface-Controlled Subsurface Safety Valve (SCSSV)

	Definition	Special Considerations	Relevant Standards
Description	A mechanical well barrier installed with production tubing in the upper completion whose purpose is to seal the tubing bore and to prevent or severely restrict the flow of fluid up the tubing when closed by command or by fail-safe function.	The SCSSV has a critical emergency function to close automatically. The production casing barrier has failed if the pressure-test acceptance criteria are not met or there is other evidence of communication in the "A" annulus.	
Design considerations	— SCSSV is: — Surface controlled; — Hydraulically operated; — Fail-safe closed upon loss of hydraulic pressure. — Regulations often dictate minimum setting depth below seabed. — It is prudent to set the SCSSV at a depth at which conditions (pressure and temperature) preclude formation of hydrates.	— Ensure sufficient operating pressure is available to operate the SCSSV. — Ensure that annulus pressure is not high enough to keep the SCSSV open if the control line leaks. — Verify control line fluid compatibility with SCSSV seals. — Cleanliness of the control line fluid is critical for operation of the SCSSV. Consider proper filtration.	— API RP 14B — API SPEC 14A
Barrier confirmation	The SCSSV is statically tested in the direction of flow.	— Consider increasing the testing frequecy when the SCSSV is exposed to high velocities or abrasive fluid. — Regulations often specify testing frequency and protocol. — Consider a low-pressure test for initial qualification.	— API RP 14B
Barrier use	— The valve should be leak-tested at regular intervals. — Allowable leakage rates are specified in API RP 14B or by regulators.	— If the leak rate cannot be measured directly, an indirect measurement can be performed by monitoring the pressure of an enclosed volume downstream of the valve. — An SCSSV that meets criteria for minimum leakage rate may be used as a barrier, unless prohibited by regulation or company policy. If a non-zero leakage rate SCSSV is used as a barrier, it is critical to understand that the pressure above the SCSSV will eventually equalize with the pressure below. This pressure will be exerted below the next barrier above the SCSSV. This does not mean the SCSSV has failed as a barrier. It does mean that when removing the barrier above the SCSSV, the full pressure from below the SCSSV must be expected below the barrier above the SCSSV. Appropriate measures to handle this pressure must be taken when removing the barrier above the SCSSV.	— API RP 14B
Barrier failure	The SCSSV has failed if the maximum allowable leak rate is exceeded.	See discussion of leak rate and pressure communication in the Barrier Use row of Table B.11 (row above).	
Barrier re-establishment	A major workover is required to retrieve the SCSSV.	If feasible, an insert SCSSV can be run on wireline inside the failed tubing-mounted SCSSV to re-establish the barrier without a major workover. However, the production bore will be reduced resulting in higher velocity for the same flow rate.	

Table B.12: Vertical Tree Tubing Hanger Plug

	Definition	Special Considerations	Relevant Standards
Description	A wireline-set bi-directional sealing plug locked in a profile in the subsea tubing hanger.	Often used during BOP removal and vertical tree installation.	— API SPEC 14L — ISO 16070
Design considerations	— Keys on plug locking mandrel must match profile in tubing hanger. — Elastomeric seal against a polished bore. — Method of equalizing pressure across plug before releasing.	— After BOP removal, the rig may leave location, leaving tree installation by another vessel at a later date. — Polished bore is subject to damage during in-well work through tubing hanger.	
Barrier confirmation	— Inflow test method: pressurize wellbore before setting plug, bleed pressure above plug, and monitor for buildup. — Pressure test from above. — Use check-set tool to confirm proper lock engagement.	— Direct pressure test from below is not possible on dead well. — When attempting to test from below after pressurizing the well, consider whether it is feasible to distinguish between sealing of this plug and the SCSSV.	
Barrier use	— Can be pressure-tested from above. — After BOP removal, monitor for leakage visually via ROV. — Can also be used to facilitate pressure test of tree upon installation.	— Debris atop plug complicates recovery. — Trapped volume between this plug and another downhole plug can lead to thermal pressure buildup in the tubing as a cool well returns to geothermal.	
Barrier failure	The vertical tree tubing hanger plug has failed if: — Leakage past plug seals is detected. — The plug lock unlatches.	Plug could be ejected from tubing hanger by pressure from below if lock fails or releases.	
Barrier re-establishment	Plug can be pulled and replaced with wireline if indication of failure exists.		

Table B.13: Horizontal Tree Crown Plugs

	Definition	Special Considerations	Relevant Standards
Description	— A wireline-set bi-directional sealing plug locked in a profile above the flow outlet in the horizontal tubing hanger (HTH). — A second crown plug is set above the first, in the internal tree cap (ITC), or in the HTH if ITC is integral to HTH.	The crown plug in a horizontal tree is a well barrier between the production tubing flow path and the subsea environment designed for the well's life cycle.	
Design considerations	— Keys on plug-locking mandrel must match profile in tubing hanger. — Typically metal-to-metal seal against a polished bore within the tree.	— Metal-to-metal seal requires a zero-backlash locking mechanism. — Pressure across plug can be equalized through horizontal tree porting before releasing plug. — Polished bore subject to damage during in-well work through tubing hanger. — Some tree design provide a port between plugs to allow venting; otherwise, pressure buildup between the plugs from the thermal effects of production can exceed the tree rating. — Internal sealing tree caps can be retrieved through the BOP.	
Barrier confirmation	— Horizontal tree provides pathways to pressure test each crown plug from below. — Pressure test from above. — Use the check-set tool to confirm proper lock engagement.	Pressure test of lower crown plug from below is not possible if fluid is being lost downhole.	
Barrier use	— May be periodically pressure-tested from above — Pressure between crown plugs may be monitored.	— Crown plug must be pulled before through-tubing well intervention. — Debris atop plug complicates recovery. — Pressure across plug can be equalized through horizontal tree porting before releasing plug.	
Barrier failure	The horizontal tree crown plug has failed if: — Leakage past plug seals is detected. — The plug lock unlatches. — The HTH unlocks.	— If both crown plugs are installed in the HTH and the HTH latch releases, flow can bypass both crown plugs. — Plug could be ejected from tubing hanger by pressure from below if lock fails or releases.	
Barrier re-establishment	Plug can be pulled and replaced with wireline if indication of failure exists.	A sealing cap may be installed over the tree top hub while mobilizing intervention equipment for plug replacement.	

Bibliography

Normative

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

1. API RP 65 Part 2, *Isolating Potential Flow Zones During Well Construction*
2. API RP 53, *Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells*
3. API RP 75, *Recommended Practice for Development of a Safety and Environmental Management Program (SEMP) for Offshore Operations and Facilities*

Informative

The following documents provide additional information about the topics in this recommended practice (RP). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document applies (including any addenda/errata).

1. 30CFR 250.514, *Well-control fluids, equipment, and operations*
2. API Bull 1INT-DG, *Interim Guidance for Design of Offshore Structures for Hurricane Conditions*
3. API Bull 2INT-MET, *Interim Guidance on Hurricane Conditions in the Gulf of Mexico*
4. API RP 2A-WSD, *Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design*
5. API RP 2RD, *Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)*
6. API RP 2SK, *Design and Analysis of Stationkeeping Systems for Floating Structures*
7. API RP 5C5 / ISO 13679, *Recommended Practice on Procedures for Testing Casing and Tubing Connections*
8. API RP 5EX, *Recommended Practice for Solid Expandable System*
9. API RP 7G, *Recommended Practice for Drill Stem Design and Operating Limits*
10. API RP 7G-2 / ISO 10407-2, *Recommended Practice for Drill Stem Element Inspection, Petroleum and natural gas industries—Rotary drilling equipment—Part 2: Inspection and classification of drill stem elements and Recommended practice for inspection and classification of used drill stem elements*
11. API RP 8B / ISO 13534, *Inspection, Maintenance, Repair, and Remanufacture of Hoisting Equipment*

12. API RP 10B-2 / ISO 10426-2, *Recommended Practice for Testing Well Cements*

13. API RP 10B-3 / ISO 10426-3, *Recommended Practice on Testing of Deepwater Well Cement Formulations*

14. API RP 10B-4 / ISO 10426-4, *Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure*

15. API RP 10B-5 / ISO 10426-5, *Recommended Practice on Determination of Shrinkage and Expansion of Well Cement Formulations at Atmospheric Pressure*

16. API RP 10D-2 / ISO 10427-2, *Recommended Practice for Centralizer Placement and Stop Collar Testing*

17. API RP 10F / ISO 10427-3, *Recommended Practice for Performance Testing of Cementing Float Equipment*

18. API RP 13B-1 / ISO 10414-1, *Recommended Practice for Field Testing Water-Based Drilling Fluids*

19. API RP 13B-2, *Recommended Practice for Field Testing Oil-based Drilling Fluids*

20. API RP 14B / ISO 10417, *Design, Installation, Repair and Operation of Subsurface Safety Valve Systems*

21. API RP 14E, *Recommended Practice for Design and Installation of Offshore Production Platform Piping systems*

22. API RP 16Q, *Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems*

23. API RP 16ST, *Coiled Tubing Well Control Equipment Systems*

24. API RP 17H / ISO 13628-8, *Remotely Operated Vehicle (ROV) Interfaces on Subsea Production Systems*

25. API RP 59, *Recommended Practice for Well Control Operations*

26. API RP 65, *Cementing Shallow Water Flow Zones in Deep Water Wells*, (adopted in 30 CFR Part 250, RIN 1010–AD19, Oil and Gas and Sulphur Operations in the Outer Continental Shelf (OCS)—Incorporate API RP 65 for Cementing Shallow Water Flow Zones as per Federal Register/Vol. 71, No. 98/Monday, May 22, 2006/Proposed Rules)

27. API RP 65-1, *Cementing Shallow Water Flow Zones in Deepwater Wells*

28. API RP 90, *Annular Casing Pressure Management for Offshore Wells*, 1st Edition, August 2006, (adopted in 30 CFR Part 250 [Docket ID: MMS–2007–OMM–0068] RIN 1010–AD47 as per Federal Register/Vol. 75, No. 85/Tuesday, May 4, 2010/Rules and Regulations)

29. API RP 1111, *Recommended Practice for the Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines (Limited State Design)*

30. API SPEC 5CRA / ISO 13680, *Specification for Corrosion Resistant Alloy Seamless Tubes for Use*

as Casing, Tubing and Coupling Stock

31. API SPEC 5CT / ISO 11960, *Specification for Casing and Tubing*

32. API SPEC 6A (www.api-u.org/6A.html) includes NACE MR0175, "Petroleum and natural gas industries—Materials for use in H2S-containing environments in oil and gas production," December 2003

33. API SPEC 10A / ISO 10426-1, *Specification for Cements and Materials for Well Cementing*

34. API SPEC 11D1 / ISO 14310, *Packers and Bridge Plugs*

35. API SPEC 14A / ISO 10432, *Specification for Subsurface Safety Valve Equipment*

36. API SPEC 14L / ISO 16070, *Specification for Lock Mandrels and Landing Nipples*

37. API SPEC 16A / ISO 13533, *Specification for Drill-through Equipment*

38. API SPEC 16D, *Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment*

39. API SPEC 17D / ISO 13628-4.2, *Subsea Wellhead and Christmas Tree Equipment*

40. API TR 5C3 / ISO 10400, *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*

41. API TR 6AF, *Capabilities of API Flanges Under Combinations*

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50. Energy Technology Laboratory (NETL), part of DOE’s national laboratory system, is owned and operated by the U.S. Department of Energy (DOE). (Figure 8.1)

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