BRITISH STANDARD

BS EN ISO 13628-4:1999

Petroleum and natural gas industries — Design and operation of subsea production systems —

Part 4: Subsea wellhead and tree equipment

The European Standard EN ISO 13628-4:1999 has the status of a British Standard

ICS 75.180.10

National foreword

This British Standard is the English language version of EN ISO 13628-4:1999. It is identical with ISO 13628-4:1999.

The UK participation in its preparation was entrusted to Technical Committee PSE/17, Materials and equipment for the petroleum and natural gas industries, which has the responsibility to:

— aid enquirers to understand the text;

— present to the responsible international/European committee any enquiries on the interpretation, or proposals for change, and keep the UK interests informed;

— monitor related international and European developments and promulgate them in the UK.

A list of organizations represented on this committee can be obtained on request to its secretary.

Cross-references

Attention is drawn to the fact that CEN and CENELEC Standards normally include an annex which lists normative references to international publications with their corresponding European publications. The British Standards which implement these international or European publications may be found in the BSI Standards Catalogue under the section entitled "International Standards Correspondence Index", or by using the "Find" facility of the BSI Standards Electronic Catalogue.

A British Standard does not purport to include all the necessary provisions of a contract. Users of British Standards are responsible for their correct application.

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Summary of pages

This document comprises a front cover, an inside front cover, the EN ISO title page, the EN ISO foreword page, the ISO title page, pages ii to vii, a blank page, pages 1 to 161, the annex ZA page, an inside back cover and a back cover.

The BSI copyright notice displayed in this document indicates when the document was last issued.

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Petroleum and natural gas industries - Design and operation of subsea production systems - Part 4: Subsea wellhead and tree equipment (ISO 13628-4:1999)

Industries du pétrole et du gaz naturel - Conception et fonctionnement des systèmes de production immergés - Partie 4: Equipements immergés de tête de puits et tête de production (ISO 13628-4:1999)

Erdöl- und Erdgasindustrien - Konstruktion und Betrieb von Unterwasser-Produktionssystemen - Teil 4: Bohrlochkopf- und E-Kreuz-Ausrüstungen für den Unterwassereinsatz (ISO 13628-4:1999)

This European Standard was approved by CEN on 3 March 1999.

CEN members are bound to comply with the CEN/CENELEC Internal Regulations which stipulate the conditions for giving this European Standard the status of a national standard without any alteration. Up-to-date lists and bibliographical references concerning such national standards may be obtained on application to the Central Secretariat or to any CEN member.

This European Standard exists in three official versions (English, French, German). A version in any other language made by translation under the responsibility of a CEN member into its own language and notified to the Central Secretariat has the same status as the official versions.

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EUROPEAN COMMITTEE FOR STANDARDIZATION
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EUROPÄISCHES KOMITEE FÜR NORMUNG

Central Secretariat: rue de Stassart, 36 B-1050 Brussels

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Foreword

The text of the International Standard ISO 13628-4:1999 has been prepared by Technical Committee ISO/TC 67 "Materials, equipment and offshore structures for petroleum and natural gas industries" in collaboration with Technical Committee CEN/TC 12 "Materials, equipment and offshore structures for petroleum and natural gas industries", the secretariat of which is held by AFNOR.

This European Standard shall be given the status of a national standard, either by publication of an identical text or by endorsement, at the latest by December 1999, and conflicting national standards shall be withdrawn at the latest by December 1999.

According to the CEN/CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and the United Kingdom.

Endorsement notice

The text of the International Standard ISO 13628-4:1999 was approved by CEN as a European Standard without any modification.

NOTE: Normative references to International Standards are listed in annex ZA (normative).

INTERNATIONAL STANDARD

ISO 13628-4

First edition
1999-06-15

Petroleum and natural gas industries — Design and operation of subsea production systems —

Part 4: Subsea wellhead and tree equipment

Industries du pétrole et du gaz naturel — Conception et fonctionnement des systèmes de production immergés

Partie 4: Équipements immergés de tête de puits et tête de production

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Foreword

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

International Standards are drafted in accordance with the rules given in the ISO/IEC Directives, Part 3.

Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

International Standard ISO 13628-4 was prepared by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, Subcommittee SC 4, *Drilling and production equipment*.

ISO 13628 consists of the following parts, under the general title *Petroleum and natural gas industries — Design and operation of subsea production systems*:

— *Part 1: General requirements and recommendations*

— *Part 2: Flexible pipe systems for subsea and marine applications*

— *Part 3: Through Flowline (TFL) systems*

— *Part 4: Subsea wellhead and tree equipment*

— *Part 5: Subsea control umbilicals*

— *Part 6: Subsea production control systems*

— *Part 7: Workover/completion riser systems*

— *Part 8: Remotely Operated Vehicles (ROV) interfaces on subsea production systems*

— *Part 9: Remotely Operated Tools (ROT) intervention systems*

Annexes E, G and H form a normative part of this part of ISO 13628. Annexes A, B, C, D, F and I are for information only.

Introduction

This part of ISO 13628 is not intended to obviate the need for sound engineering judgement as to when and where this part of ISO 13628 should be utilized, and the users of this part of ISO 13628 should be aware that additional or differing requirements may be needed to meet the needs for the particular service intended or to meet local legislation.

The objective of this part of ISO 13628 is to define clear and unambiguous requirements which will facilitate international standardization in order to enable safe and economic development of offshore oil and gas fields by the use of subsea wellhead and christmas tree equipment. This part of ISO 13628 is written in a manner which will allow the use of a wide variety of technology varying from the well established to the state of the art. This part of ISO 13628 does not wish to restrict or deter the development of new technology. However, the reader is encouraged to closely look at standard interfaces and the re-use of intervention systems and tools, in the interests of minimizing life cycle costs and increasing reliability by the use of proven interfaces.

The International Organization for Standardization (ISO) draws attention to the fact that it is claimed that compliance with this part of ISO 13628 may involve the use of one or more patents concerning certain of the horizontal tree designs given in subclause 6.1.2, annex B and Figures 4, B.1, B.2 and B.3.

The ISO takes no position concerning the evidence, validity and scope of this patent right.

The holder of this patent right has assured the ISO that he is willing to negotiate licences under reasonable and non-discriminatory terms and conditions with the applicants throughout the world. In this respect, the statement of the holder of this patent right is registered with the ISO.

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Attention is drawn to the possibility that some of the elements of this part of ISO 13628 may be the subject of patent rights other than those identified above. ISO shall not be held responsible for identifying any or all such patent rights.

This part of ISO 13628 is based on API Specification 17D First edition, October 30, 1992, *Specification for Subsea Wellhead and Christmas Tree Equipment* including Supplement 1 (March 1, 1993).

Petroleum and natural gas industries — Design and operation of subsea production systems —

Part 4:
Subsea wellhead and tree equipment

1 Scope

1.1 This part of ISO 13628 specifies subsea copewellhead, conventional mudline wellhead, drill through mudline wellhead, conventional subsea trees and horizontal subsea trees. It also specifies the associated tooling necessary to handle, test and install the equipment. It also specifies the areas of design, material, welding, quality control (including factory acceptance testing), marking, storing and shipping for both individual sub-assemblies (used to build complete subsea tree assemblies) and complete subsea tree assemblies.

Where applicable, this part of ISO 13628 may also be used for equipment on satellite, cluster arrangements and multiple well template applications.

1.2 Equipment which is within the scope of this part of ISO 13628 is listed as follows:

a) Subsea trees

— tree connectors and tubing hanger spools;

— valves, valve blocks, and valve actuators;

— chokes and choke actuators;

— bleed, test and isolation valves;

— TFL wye spool;

— re-entry spool;

— tree cap;

— tree piping;

— tree guide frames;

— tree running tools;

— tree cap running tools;

— tree mounted flowline/umbilical connector;

— control module/pod running/retrieval and testing tools;

— flowline base running/retrieval tools;

— tree mounted controls interfaces (instrumentation, sensors, hydraulic tubing/piping and fittings, electrical controls cable and fittings).

b) *Subsea wellheads*

- conductor housings;
- wellhead housings;
- casing hangers;
- seal assemblies;
- guidebases;
- bore protectors and wear bushings;
- corrosion caps.

c) Conventional mudline suspension systems

- wellheads;
- running tools;
- casing hangers;
- casing hanger running tool;
- tieback tools for subsea completion;
- subsea completion adaptors for mudline wellheads;
- tubing spools;
- corrosion caps.

d) Drill through mudline suspension systems

- conductor housings;
- surface casing hangers;
- wellhead housings;
- casing hangers;
- annulus seal assemblies;
- bore protectors and wear bushings;
- abandonment caps.

e) Tubing hanger systems

- tubing hangers;
- running tools.

f) Miscellaneous equipment

- flanged end and outlet connections;

— clamp hub-type connections;

— threaded end and outlet connections;

— other end connections;

— studs and nuts;

— ring joint gaskets;

— intervention equipment;

— guide line establishment equipment.

1.3 Equipment which is beyond the scope of this part of ISO 13628 includes:

— subsea wireline/coiled tubing BOPs;

— workover and production risers;

— control systems and control pods;

— platform tiebacks;

— primary protective structures;

— subsea process equipment;

— subsea manifolding;

— subsea wellhead tools;

— repair and rework;

— multiple well template structures;

— mudline suspension high pressure risers;

— template piping;

— template interfaces.

1.4 Equipment definitions are given in clause 3 and equipment use and function are explained in annexes A to F.

Service conditions and product specification levels are given in clause 4.

Critical components are those parts having requirements specified in this part of ISO 13628.

Rework and repair of used equipment are beyond the scope of this part of ISO 13628.

2 Normative references

The following normative documents contain provisions which, through reference in this text, constitute provisions of this part of ISO 13628. For dated references, subsequent amendments to, or revisions of, any of these publications do not apply. However, parties to agreements based on this part of ISO 13628 are encouraged to investigate the possibility of applying the most recent editions of the normative documents indicated below. For undated references, the latest edition of the normative document referred to applies. Members of ISO and IEC maintain registers of currently valid International Standards.

ISO 10422, *Petroleum and natural gas industries — Threading, gauging, and thread inspection of casing, tubing, and line pipe threads — Specification.*

ISO 10423:1994, *Petroleum and natural gas industries — Drilling and production equipment — Specification for valves, wellhead and Christmas tree equipment.*

ISO 10424, *Petroleum and natural gas industries — Drilling and production equipment — Specification for rotary drilling equipment.*

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

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

ISO 13628-2, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 2: Flexible pipe systems for subsea and marine applications.*

ISO 13628-9, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 9: Remote Operated Tools (ROT) intervention systems.*

ANSI/ASME B16.11, *Forged Fittings, Socket-Welding and Threaded.*

ANSI/ASME B31.3, *Process Piping.*

ANSI/NACE MR0175, *Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment.*

ANSI/SAE J517, *Hydraulic Hose.*

ANSI/SAE J343, *Tests and Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies.*

API Spec 16A[1)]

API Spec 16R[2)]

API RP 17C[3)]

AWS D1.1, *Structural Welding Code.*

Det Norske Veritas Offshore Standard RP B401,*Cathodic Protection Design.*

INACE RP0176, *Cathodic protection of steel fixed offshore structures.*

NAS 1638-64, *National Aerospace Standard-Cleanliness Requirements of Parts Used in Hydraulic Systems.*

PFI Standard ES-24, *Pipe Bending Methods, Tolerances, Process and Material Requirements.*

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1) For the purposes of this part of ISO 13628, API Spec 16A will be replaced by ISO 13533 when the latter becomes publicly available.

2) For the purposes of this part of ISO 13628, API Spec 16R will be replaced by ISO 13625 when the latter becomes publicly available.

3) For the purposes of this part of ISO 13628, API Spec 17C will be replaced by ISO 13628-3 when the latter becomes publicly available.

3 Terms, definitions, symbols and abbreviations

For the purposes of this part of ISO 13628, the following terms, definitions, symbols and abbreviations apply.

3.1 Terms and definitions

3.1.1
annulus seal assembly
mechanism which provides pressure isolation between each casing hanger and the wellhead housing

3.1.2
bore protector
device which protects internal bore surfaces during drilling or workover operations

3.1.3
check valve
device designed to restrict flow in one direction

3.1.4
completion riser
riser that is designed to fit inside a BOP to allow installation of a tubing hanger, and may also be suitable for connection to the tree upper connection for use as a means for running the tree or for use as a workover riser

3.1.5
conductor housing
top of the first casing string which forms the basic foundation of the subsea wellhead and provides attachments for guidance structures

3.1.6
corrosion cap
cap placed over the wellhead to protect it from contamination by debris, marine growth, or corrosion during temporary abandonment of the well

3.1.7
corrosion-resistant alloys
ferrous and non-ferrous alloys which are more corrosion resistant than low alloy steels

NOTE This term includes nickel alloys, stainless steels, copper-nickel alloys and titanium.

3.1.8
depth rating
maximum rated working depth of a piece of equipment at a given set of operating conditions

3.1.9
downstream
direction of movement away from the reservoir

3.1.10
extension sub
sealing tubular member that provides tree bore continuity between adjacent tree components

3.1.11
fail closed valve
actuated valve designed to fail to the closed position

3.1.12
fail open valve
actuated valve designed to fail to the open position

3.1.13
flowline
any pipeline connecting to the subsea tree assembly

3.1.14
flowline connector support frame
structural frame which receives and supports the flowline connector and transfers flowline loads back into the wellhead or seabed anchored structure

3.1.15
flowline connector system
equipment used to attach subsea pipelines and/or control umbilicals to a subsea tree

NOTE The system may include means to guide the end of the pipeline or umbilical into place and may include remote connection or disconnection capability.

3.1.16
flow loops
piping which connects the outlet(s) of the subsea tree to the subsea flowline connection and/or to other tree piping connections (crossover piping, etc.)

3.1.17
guide funnel
tapered enlargement at the end of a guidance member to provide primary guidance over another guidance member

3.1.18
guide lineless systems
systems which do not depend on the establishment of guide lines from the seafloor to the surface vessel for guidance and alignment of subsea equipment during installation, operation, intervention, or retrieval

3.1.19
guide lines
taut lines from the seafloor to the surface for the purpose of guiding equipment to the seafloor structure

3.1.20
high pressure riser
tubular member which extends the wellbore from the mudline wellhead or tubing spool to a surface BOP

3.1.21
inboard tree piping
subsea tree piping which is upstream of the first tree wing valve

3.1.22
intervention fixtures
devices or features permanently fitted to subsea well equipment to facilitate subsea intervention tasks including, but not limited to:

— grasping intervention fixtures

— docking intervention fixtures

— landing intervention fixtures

— linear actuator intervention fixtures

— rotary actuator intervention fixtures

— fluid coupling intervention fixtures

3.1.23
intervention system
means to deploy or convey intervention tools to subsea well equipment to carry out intervention tasks including:

— ROV;

— ROT;

— ADS;

— diver.

3.1.24
intervention tools
device or ROT deployed by an intervention system to mate or interface with intervention fixtures

3.1.25
LWRP
unitized assembly that interfaces with the tree upper connection and allows sealing of the tree vertical bore(s)

NOTE This may also allow disconnection from the top connection of the LWRP, to permit retrieval of the workover riser, while wireline equipment is in the tree bore(s).

3.1.26
mudline suspension system
drilling system consisting of a series of housings used to support casing strings at the mudline, installed from a bottom-supported rig using a surface BOP

3.1.27
nonpressure-containing/controlling parts
structural and other parts that do not contain or control pressure, such as guidebases, guideframes, and wear bushings

3.1.28
orienting bushings
non-pressure-containing parts which are used to orient equipment or tools with respect to the wellhead

3.1.29
outboard tree piping
subsea tree piping which is downstream of the first tree wing valve and upstream of flowline connector (see flow loop)

3.1.30
permanent guidebase
structure that sets alignment and orientation of the wellhead system and provides entry guidance for running equipment on or into the wellhead assembly

3.1.31
plug catcher
device at the bottom of the tubing hanger annulus bore to prevent the wireline plug from passing through the tubing hanger when an annulus string is not used

3.1.32
pressure-containing parts
those parts whose failure to function as intended would result in a release of retained fluid to the environment

EXAMPLES Bodies, bonnets and stems.

3.1.33
pressure controlling parts
those parts intended to control or regulate the movement of pressurized fluids, such as valve bore sealing mechanisms and hangers

3.1.34
power operated fail closed valve
hydraulically or electrically actuated valve designed to fail to the closed position

3.1.35
rated working pressure
maximum internal pressure equipment is designed to contain and/or control

NOTE Working pressure is not to be confused with test pressure.

3.1.36
re-entry spool
tree upper connection profile, which allows remote connection of a tree running tool, LWRP or tree cap

3.1.37
running tool
tool used to run, retrieve, position, or connect subsea equipment remotely from the surface

EXAMPLES Tree running tools, tree cap running tools, flowline connector running tools, etc.

3.1.38
second end connection
connection made at the termination of the pipelaying process

3.1.39
split gate valve
valve where the gate is made of two or more pieces which are capable of being energized to seal both upstream and downstream at the same time

3.1.40
subsea BOP
blow-out preventer stack designed for use on subsea wellheads.

NOTE This provides the capability to remotely shear and seal the wellhead bore and also provides the capability to circulate from the surface through the wellhead.

3.1.41
subsea casing hangers
device that supports a casing string in the wellhead at the mudline

3.1.42
subsea completion equipment
specialized tree and wellhead equipment used to complete a well below the surface of a body of water

NOTE This may be made above a subsea wellhead or mudline suspension system. Equipment includes subsea wellhead, tree, tree appurtenances (e.g., tree cap, control pod), and associated subsea tree running tools.

3.1.43
subsea wellhead housing
pressure-containing housing that provides a means for suspending and sealing the well casing strings installed during a floating drilling operation

3.1.44
subsea wireline/coiled tubing BOP
subsea BOP that attaches to the top of a subsea tree to facilitate wireline or coiled tubing intervention

3.1.45
swivel flange (type 17SV)
flange assembly consisting of a central hub and a loose flange rim which is free to rotate about the hub

NOTE The rotating flange rim has holes to accept bolts. The central hub has a sealing mechanism which will engage an ISO ring gasket. ISO type SV swivel flanges will mate with standard ISO type 17SS and 6BX flanges of the same size and pressure rating.

3.1.46
tieback adapter
device used to provide the interface between mudline suspension equipment and subsea completion equipment

3.1.47
tree cap
protective cover for the upper tree connection

NOTE This may be used to contain pressure, and may be an integral part of the tree control system.

3.1.48
tree connector
mechanism to join and seal a subsea tree to a subsea wellhead

NOTE This may require diver assistance for installation, or be hydraulically actuated to permit remote operation.

3.1.49
tree guide frame
structural framework to provide guidance with the PGB interface, for installation of the subsea tree on the subsea wellhead, and which also provides support for tree flowlines and connection equipment, control pods, anodes, and counterbalance weights

3.1.50
tree upper connection
uppermost fitting of a subsea tree which allows full bore access to the tree

NOTE The connection profile may be API or other proprietary types (see re-entry spool).

3.1.51
tree side outlet
point where a bore exits at the side of the tree block

3.1.52
umbilicals
hose, tubing, piping, and/or electrical conductors which direct fluids and/or electrical current or signals to or from subsea trees

NOTE Umbilical lines are typically used for control, monitoring, and/or injection functions.

3.1.53
upstream
direction of movement to the reservoir

3.1.54
valve block
integral block containing two or more valves

3.1.55
wear bushings
bore protector which also protects the casing hanger below it

3.1.56
wellhead housing pressure boundary
wellhead housing from the top of the wellhead to where the lowermost seal assembly seals

3.1.57
workover riser
equipment to provide a conduit from the tree upper connection to the surface and allows the passage of wireline tools.

NOTE It has to resist environmental wind, wave and current forces.

3.1.58
wye spool
spool between the master and swab (crown) valves of a TFL tree, that allows the passage of TFL tools from the flowlines into the bores of the tree

3.2 Symbols and abbreviations

ADS	atmospheric diving system
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AWS	American Welding Society
BOP	blow-out preventer
CRA	corrosion-resistant alloys
EDP	emergency disconnect package
FEA	finite element analysis
FAT	factory acceptance test
ID	inside diameter
LRP	lower riser package
LWRP	lower workover riser package
MIL-STD	Military Standard (USA)
MRWP	maximum rated working pressure
MSS	Manufacturer's Standardization Society of the Valve and Fittings Industry
NACE	National Association of Corrosion Engineers
OD	outside diameter
OEC	other end connectors
PFI	Pipe Fabrication Institute
PGB	permanent guide base
PMR	per manufacurer's rating
PR2	performance requirement level two
PSL	product specification level

RMS	root mean square
ROV	remotely operated vehicle
ROT	remotely operated tool
S_b	bending stress
S_m	membrane stress
S_y	yield stress
SCSSV	surface-controlled subsurface safety valve
SWL	safe working load
TFL	through-flowline
TGB	temporary guide base
WCT-BOP	wireline/coil tubing blow-out preventer
XT	tree

4 Service conditions and product specification levels

4.1 Service conditions

4.1.1 General

Service conditions refer to classifications for pressure, temperature and the various wellbore constituents and operating conditions for which the equipment will be designed.

4.1.2 Pressure ratings

Pressure ratings indicate maximum rated working pressures expressed as megapascals (MPa) with equivalent pounds per square inch (psi) in parentheses. It should be noted that pressure is gauge pressure.

4.1.3 Temperature ratings

Temperature ratings indicate temperature ranges, from minimum ambient to maximum flowing fluid temperatures, expressed in degrees Celsius (°C) with equivalent degrees Fahrenheit (°F) given in parentheses.

4.1.4 Material class ratings

Materials class ratings indicate the material of the equipment components. A guide line for the basic wellbore constituents and operating conditions is covered in clause 12.

4.2 Product specification levels (PSL)

All pressure-containing and pressure-controlling parts of equipment manufactured to this part of ISO 13628 shall comply with the requirements of PSL 2 or PSL 3 as established in ISO 10423 or PSL 3G as defined in 5.2.3 and 5.4.2. These PSL designations define different levels of requirements. Clause 12 provides guide lines for selecting an acceptable PSL.

Structural components and other nonpressure-containing/controlling parts of equipment manufactured to this part of ISO 13628 need not comply with the requirements of PSL 2, PSL 3 or PSL 3G. PSL rating of assembled wellhead or tree equipment shall be determined by the lowest PSL rating of any pressure-containing/controlling component in the assembly.

5 Common system requirements

5.1 Design and performance requirements

5.1.1 General

Product capability is defined by two main aspects:

Performance verification testing (see 5.1.7), which is intended to demonstrate and qualify performance of generic product families, as being representative of defined product variants.

Performance requirements, which define the operating capability of the specific "as-shipped" items (see this subclause and 5.1.2), which is demonstrated by reference to both factory acceptance testing and relevant performance verification testing data.

Performance requirements are specific and unique to the product in the as-shipped condition. All products shall be designed to perform in accordance with 5.1, 6.1, and clauses 7 to 11.

5.1.1.1 Pressure integrity

Product designs shall be capable of withstanding rated working pressure at rated temperature without deformation to the extent that any other performance requirement is not met, providing stress criteria are not exceeded.

5.1.1.2 Thermal integrity

Product designs shall be capable of functioning throughout the temperature range for which the product is rated.

5.1.1.3 Materials

Product designs shall be capable of functioning with appropriate material class selected from Table 1.

Table 1 — Material requirements

Materials class [a]	Minimum material requirements	
	Body, bonnet and flange	**Pressure controlling parts, stems and mandrel hangers**
AA-General service	Carbon or low alloy steel	Carbon or low alloy steel
BB-General service	Carbon or low alloy steel	Stainless steel
CC-General service	Stainless steel	Stainless steel
DD-Sour service [b]	Carbon or low alloy steel [c]	Carbon or low alloy steel [c]
EE-Sour service [b]	Carbon or low alloy steel [c]	Stainless steel [c]
FF-Sour service [b]	Stainless steel	Stainless steel [c]
HH-Sour service [b]	CRAs [c]	CRAs [c]

[a] Refer to 5.1.2.3 for information regarding material class selection.
[b] As defined in ANSI/NACE MR0175.
[c] In compliance with ANSI/NACE MR0175.

5.1.1.4 Leakage

No observable leakage is allowed.

5.1.1.5 Load capability

Product designs shall be capable of sustaining rated loads without deformation to the extent that any other performance requirement is not met, providing stress criteria are not exceeded. Product designs that support tubulars shall be capable of supporting the rated load without collapsing the tubulars below the drift diameter.

5.1.1.6 Cycles

Product designs shall be capable of performing and operating in service as intended for the number of operating cycles as specified by the manufacturer.

5.1.1.7 Operating force or torque

Products shall be designed to operate within the manufacturer's force or torque specification, as applicable and where applicable as verified in performance verification testing.

5.1.1.8 The design shall consider the venting of trapped pressure and ensure that this can safely be released prior to the disconnection of fittings, assemblies, etc.

5.1.2 Service conditions

5.1.2.1 Pressure ratings

5.1.2.1.1 General

Pressure ratings shall comply with the following paragraphs. Where small diameter lines, such as SCSSV control lines or chemical injection lines, pass through a cavity, such as the tree/tubing hanger cavity, equipment bounding that cavity shall be rated for the maximum pressure in any of the lines, unless a means is provided to monitor and relieve the cavity pressure in the event of a leak in any of those lines. In addition, the effects of external loads (i.e. bending moments, tension), ambient hydrostatic loads and fatigue shall be considered. For the purpose of this part of ISO 13628, pressure ratings shall be interpreted as differential pressure. For clarity, the following examples are offered.

EXAMPLE 1 Pressure-containing components (such as bodies, bonnets and end connectors) rated for 69,0 MPa (10 000 psi) are tested, marked for 69,0 MPa (10 000 psi) differential pressure service. If the application is in a water depth that results in 17,25 MPa (2 500 psi) external ambient pressure, these components could be used up to a shut-in pressure of 86,25 MPa (12 500 psi), even though their MRWP is marked as 69,0 MPa (10 000 psi).

EXAMPLE 2 Pressure-controlling components (such as valve bore sealing mechanisms and tubing plugs) may be isolated from the external ambient pressure under certain operating conditions. For example, valves on a subsea gas well may have little or no pressure on the "downstream" side of their gates when the valves are closed and the flowline pressure is vented to atmosphere. In such cases, external ambient seawater pressure would not reduce the "differential pressure" acting across the valve bore sealing mechanism. Thus, in most cases, valves in subsea gas service cannot be used in applications where the shut-in pressures would exceed the MRWP stamped on the equipment.

EXAMPLE 3 Pressure-controlling components (such as valve bore sealing mechanisms and tubing plugs) on subsea oil wells may benefit from "external" downstream pressure due to hydrostatic head of the oil column in the flowline. In such cases, the equipment could be used at pressures above the marked pressure rating. For example, if a 69,0 MPa (10 000 psi) rated valve is used in a water depth that results in 12,1 MPa (1 750 psi) minimum hydrostatic pressure downstream of the valve, the valve could be used up to a shut-in pressure of 81,1 MPa (11 750 psi).

Gas mixed with oil in the flowline could reduce the hydrostatic pressure acting downstream of the closed valve. This factor shall be taken into account when calculating the maximum allowable shut-in pressure for the specific application.

Seal designs should consider conditions where deep water can result in reverse pressure acting on the seal due to external hydrostatic pressure exceeding internal bore pressure. All operating conditions (i.e. commissioning, testing, start-up, operation, blowdown, etc.) should be considered.

5.1.2.1.2 Subsea trees

Pressure-controlling and -containing parts that comprise the subsea tree assembly shall be designed to operate in only the following standard rated working pressures: 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) and 103,5 MPa (15 000 psi).

5.1.2.1.3 Tubing hangers

Tubing hangers and associated seals, may also be designed in 49,5 MPa (7 500 psi), 86,3 MPa (12 500 psi) and 120,7 MPa (17 500 psi) rated working pressures in addition to the standard pressures given in 5.1.2.1.2.

5.1.2.1.4 Subsea wellhead equipment

The standard MRWPs for subsea wellheads shall be 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) and 103,5 MPa (15 000 psi). Tools and internal components such as casing hangers may have other pressure ratings, depending on size and operating requirements.

5.1.2.1.5 Conventional mudline equipment

Standard rated working pressures do not apply to conventional mudline equipment; instead, each equipment piece shall be rated for working pressure in accordance with the methods given in clause 10.

5.1.2.1.6 Hydraulic control components

Hydraulic control components other than for SCSSV circuits shall have standard MRWPs of 10,3 MPa (1 500 psi) or 20,7 MPa (3 000 psi) or in accordance with the manufacturer's written specification. Hydraulic control circuits for SCSSVs shall have standard working pressures of 34,5 MPa (5 000 psi), 49,5 MPa (7 500 psi), 69,0 MPa (10 000 psi), 86,3 MPa (12 500 psi), 103,5 MPa (15 000 psi) or 120,7 MPa (17 500 psi) or in accordance with the manufacturer's written specification.

5.1.2.1.7 Threaded equipment limitations

Equipment designed with internal screw threads shall be limited to the thread sizes and rated working pressures given in Table 2. Ratings do not include tubing and casing hangers.

Table 2 — Pressure ratings for internal ISO threaded end or outled connections

Type of API thread	Size mm (in)	Rated working pressure MPa (psi)
Line pipe (nominal sizes)	12,7 (1/2)	69,0 (10 000)
	19,1 to 50,8 (3/4 to 2)	34,5 (5 000)
	63,5 to 152,4 (2 1/2 to 6)	20,7 (3 000)
Tubing, non-upset and ext. upset round thread	26,7 to 114,3 (1,050 to 4 1/2)	34,5 (5 000)
Casing (8 round, buttress and extreme line)	114,3 to 273,1 (4 1/2 to 10 3/4)	34,7 (5 000)
	298,5 to 339,7 (11 3/4 to 13 3/8)	20,7 (3 000)
	406,4 to 508 (16 to 20)	13,8 (2 000)

5.1.2.1.8 Other equipment

The design of other equipment such as running, retrieval, and test tools shall comply with purchaser's/manufacturer's specifications.

5.1.2.2 Temperature ratings

5.1.2.2.1 Standard operating temperature rating

Subsea equipment covered by this part of ISO 13628 shall be designed and rated to operate throughout a temperature range of 2 °C to 120 °C (35 °F to 250 °F). Consideration shall be given to lower temperature effects on choke bodies and associated downstream piping when subject to gas blowdown.

5.1.2.2.2 Standard operating temperature rating adjusted for seawater cooling

If the manufacturer shows through analysis or testing that certain equipment on subsea wellhead, mudline suspension, and tree assemblies, such as valve and choke actuators, will not exceed 65 °C (150 °F) when operated subsea with a retained fluid at 120 °C (250 °F), then this equipment may be designed and rated to operate throughout a temperature range of 2 °C to 65 °C (35 °F to 150 °F).

5.1.2.2.3 Non-standard operating temperature rating

If manufacturer's subsea equipment is to be rated to temperatures below 2 °C (35 °F) or greater than 120 °C (250 °F), then the subsea equipment shall be tested at rated working pressure or greater as specified in 5.1.7 at the new temperatures, and the new temperature range shall be clearly marked on the equipment as specified in 5.5.4. Adjustments in temperature rating as specified in 5.1.2.2.2 shall be clearly marked.

5.1.2.2.4 Temperature design considerations

The design shall take into account the effects of temperature gradients and cycles on the metallic and non-metallic parts of the equipment.

5.1.2.2.5 Storage/test temperature considerations

If subsea equipment is to be stored or tested on the surface at temperatures outside of its temperature rating, then the manufacturer should be contacted to determine if special storage or surface testing procedures are recommended. Manufacturers shall document any such special storage or surface testing considerations.

5.1.2.3 Material class ratings

5.1.2.3.1 General

Equipment shall be designed with materials which meet or exceed the requirements given in Table 1. The table provides material classes for increasing levels of severity of service conditions and relative corrosivity.

Minimum material requirements include nonmetalics whose performance shall be consistent with the metal alloys listed in Table 1. Providing the mechanical properties can be met, stainless steels may be used in place of carbon and low alloy steels and also CRAs may be used in place of stainless steels.

5.1.2.3.2 Material classes

Choosing material classes is the ultimate responsibility of the user, however the user may specify the service conditions leaving the supplier free to recommend a fit for service solution.

Refer to 12.4 for recommendations (not requirements) for material class selection. Material requirements shall comply with Table 1. All pressure-containing components shall be treated as "bodies" for determining material requirements from Table 1. However, in this part of ISO 13628, other wellbore pressure boundary penetration equipment, such as grease/bleeder fittings and lockdown screws, shall be treated as "stems" as set forth in Table 1. Metal seals shall be treated as pressure-controlling parts in Table 1.

5.1.2.4 External hydrostatic pressure

In subsea applications, external hydrostatic pressure may be higher than internal system pressure. This external loading situation shall be considered in the design of standard equipment in accordance with this part of ISO 13628.

5.1.3 Design methods

Fatigue consideration shall be evaluated where applicable to equipment in this part of ISO 13628. Reference [20] (Appendix 5, *Methodology*) or other recognized standards may be used when calculating fatigue. Localized bearing stress values are beyond the scope of this part of ISO 13628.

5.1.3.1 Standard ISO flanges, hubs, and threaded equipment

Flanges and hubs for subsea use shall be designed in accordance with 7.1, 7.2 and/or 7.3.

5.1.3.2 Pressure-controlling components

Casing hangers, tubing hangers, and all pressure-controlling components, except for conventional mudline suspension wellhead equipment, shall be designed in accordance with ISO 10423.

Pressure-controlling components of conventional mudline suspension equipment shall be designed in accordance with clause 10.

5.1.3.3 Pressure-containing components

Wellheads, bodies, bonnets and other pressure-containing components shall be designed in accordance with ISO 10423.

For purpose of design, lock screws and stems shall comply with ISO 10423.

5.1.3.4 Closure bolting

Refer to annex G for recommended bolt make-up torque.

Closure bolting of all 34,5 MPa (5 000 psi) 6BX and 17SS flanges shall be made up to 1/2 specified minimum yield stress. Closure bolting of all 69,0 MPa (10 000 psi) 6BX and 17SV flanges shall be made up to 2/3 specified minimum yield stress.

Closure bolting manufactured from carbon or alloy steel shall not be used in submerged service at hardness levels exceeding Rockwell "C" 32 due to the risk of hydrogen induced cracking.

The maximum allowable tensile stress for closure bolting shall be determined considering initial bolt up, rated working pressure and hydrostatic test pressure conditions. Bolting stresses, based on the root area of the thread, shall not exceed the following limits:

$$S_a = 0,83\ S_y \tag{1}$$

where

S_a is the maximum allowable tensile stress;

S_y is the bolting material specified minimum yield strength.

Bolting stresses shall be determined considering all loading on the closure, including pressure acting over the seal area, gasket loads and any additive mechanical and thermal loads.

5.1.3.5 Unpressurized primary structural components

Unpressurized primary structural components such as guide bases shall be designed in accordance with accepted industry practices and documented in accordance with 5.1.5. A safety factor of 1,5 or more shall be used in the design calculations or industry codes may be used. It should be noted that many codes already include safety factors. Alternatively FEA may be used to demonstrate that applied loads do not result in deformation to the extent that any other performance requirement is not met. As an alternative, a design verification load test of 1,5 times its rated capacity may be substituted for design analysis. The component must sustain the test loading without deformation to the extent that any other performance requirements are effected, and the test documents shall be retained.

5.1.3.6 Specific equipment

Refer to ISO 10423. In addition, refer to clauses 6 to 11 for additional design requirements. If specific design requirements in clauses 6 to 11 differ from the general requirements in clause 5, then the equipment's specific design requirements shall take precedence.

5.1.3.7 Design of lifting devices

5.1.3.7.1 Performance verification testing

Performance verification testing of lifting devices shall be done in accordance with 5.1.7.5 or in accordance with local legislation if the requirements in this part of ISO 13628 are exceeded.

5.1.3.7.2 Padeyes

Padeyes shall be designed in accordance with documented industry practice or local legislation where applicable, using a design factor of safety of 4 or greater based on minimum specified ultimate material strength at the maximum rated pickup angle. Load capacities of padeyes shall be marked as specified in 5.5.2.

5.1.3.7.3 Other lifting devices

Other lifting devices such as running tools shall be designed as specified in 5.1.3.5. If the lifting devices are either pressure-containing or -controlling, and are designed to be pressurized during lifting operations, then the load capacity shall include stresses induced by internal rated working pressure. Load capacity shall be marked on all lifting devices as specified in 5.5. Local legislation should be checked for design requirements which may exceed the above.

Running tools for subsea wellhead equipment and drill through mudline equipment are beyond the scope of this part of ISO 13628. Refer to annex H for recommended guide lines for design of these tools.

Specific requirements for design of conventional mudline equipment running tools are given in clause 10.

5.1.4 Miscellaneous design information

5.1.4.1 General

End or outlet connections shall be an integral part of the body or attached by welding in accordance with the requirements of this part of ISO 13628.

5.1.4.2 Fraction to decimal equivalence

Table 304.1 of ISO 10423:1994 gives the equivalent fraction and decimal values.

5.1.4.3 Tolerances

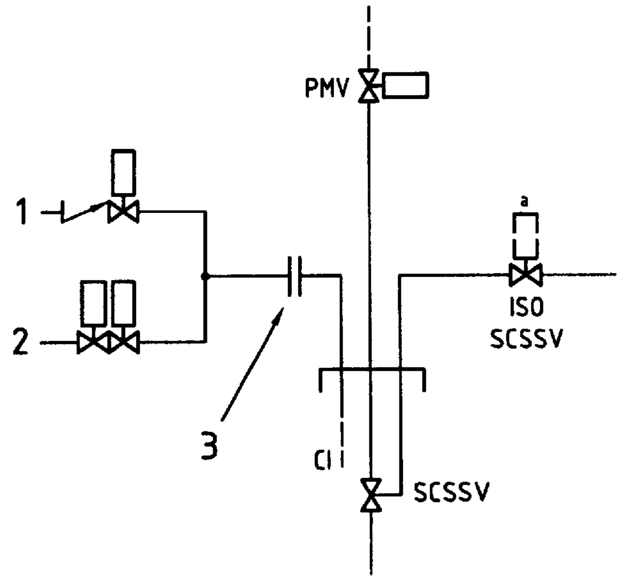
Unless otherwise specified in tables or figures of this part of ISO 13628, the following tolerances shall apply:

Dimension	Tolerance
X.XX	±0,5 mm (0,02 in)
X.XXX	±0,1 mm (0,005 in)

5.1.4.4 End and outlet bolting

5.1.4.4.1 Hole alignment

End and outlet bolt holes for ISO flanges shall be equally spaced and shall straddle the common centre line. Refer to Figure 1.



CIV Chemical injection valve
PMV Production master valve

Key

1, 2 CIV options

3 Flange or clamp hub

[a] Designed to prevent hydraulic lock opening of SCSSV

NOTE The dotted inclusions are optional.

Figure 1 — Examples of tree valving for downhole chemical injection and SCSSVs

5.1.4.4.2 Stud thread engagement

Stud thread engagement length into the body of ISO studded flanges shall be a minimum of one times the OD of the stud.

5.1.4.5 Other bolting

The stud thread anchoring means shall be designed to sustain a tensile load equivalent to the load which can be transferred to the stud through a fully engaged nut.

5.1.4.6 Test, vent, injection and gauge connections

5.1.4.6.1 Sealing

All test, vent, injection and gauge connections shall provide a leaktight seal at the test pressure of the equipment in which they are installed.

A means shall be provided such that any pressure behind a test, vent, injection or gauge connector can be safely vented prior to release.

5.1.4.6.2 Test and gauge connection ports

Test and gauge connection ports for 69,0 MPa (10 000 psi) working pressure and below shall be internally threaded in conformance with methods specified in ISO 10423 and shall not be less than 12,7 mm (1/2 in) nominal line pipe thread. High-pressure connections as described for 103,5 MPa (15 000 psi) equipment may also be used. Test and gauge connections for 103,5 MPa (15 000 psi) working pressure shall be in accordance with ISO 10423.

5.1.4.6.3 Vent and injection ports

Vent and injection ports shall meet the requirements of 5.4.6.

5.1.4.7 External corrosion control programme

External corrosion control for subsea trees and wellheads shall be provided by appropriate materials selection, coating systems, and cathodic protection. A corrosion control programme is an ongoing activity which consists of testing, monitoring, and replacement of spent equipment. The implementation of a corrosion control programme is beyond the scope of this part of ISO 13628.

5.1.4.8 Coatings (external)

5.1.4.8.1 Methods

The coating system and procedure used shall comply with the written specification of the equipment manufacturer, the coating manufacturer, or annex I.

5.1.4.8.2 Record retention

The manufacturer shall maintain, and have available for review, documentation describing the coating systems and procedures used.

5.1.4.8.3 Colour selection

Underwater visibility should be considered when selecting coating colours and shall be in accordance with ISO 13628-1.

5.1.4.9 Cathodic protection

Cathodic protection system design requires the consideration of the external area of the equipment to be protected. It is the responsibility of the equipment manufacturer to document and maintain the information on the area exposed to replenished seawater of all equipment supplied according to 5.1.5. This documentation shall contain the following information as a minimum:

— location and size of wetted surface area for specific materials, coated and uncoated;

— areas where welding is allowed or prohibited;

— materials of construction and coating systems applied to external wetted surfaces;

— control line interface locations;

— flowline interfaces.

The following cathodic protection design codes shall apply:

— NACE RP0176;

— Det Norske Veritas Offshore Standard RP B401.

Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Care should be exercized in the selection of materials for applications requiring high strength, corrosion resistance, and resistance to hydrogen embrittlement. Materials which have shown this susceptibility include martensitic stainless steels and more highly alloyed steels having yield strengths over 1 035,0 MPa (150 000 psi). Other materials subject to this phenomenon are hardened low alloy steels, particularly with hardness levels of Rockwell "C" 35 or greater, precipitation hardened nickel-copper alloys, and some high-strength titanium alloys.

5.1.5 Design documentation

Documentation of designs shall include methods, assumptions, calculations and design requirements. Design requirements shall include, but not be limited to those criteria for size, test and operating pressures, material, environmental and ISO standard requirements, and other pertinent requirements upon which the design is to be based. Design documentation media shall be clear, legible, reproducible and retrievable. Design documentation retention shall be for a minimum of 5 years after the last unit of that model, size and rated working pressure is manufactured. All design requirements shall be recorded in a manufacturer's specification which shall reflect the requirements of this part of ISO 13628, the purchaser's specification or manufacturer's own requirements. The manufacturer's specification may consist of text, drawings, computer files, etc.

5.1.6 Design review

Design documentation shall be reviewed and verified by any qualified and competent individual other than the individual who created the original design.

5.1.7 Performance verification testing

5.1.7.1 Introduction

This subclause defines the performance verification test procedures to be used to qualify product designs.

5.1.7.2 General

Equipment or fixtures used to qualify designs using these performance verification procedures shall be representative of production models in terms of design, dimensions, and materials. If a product design undergoes any changes in fit, form, function or material, the manufacturer shall document the impact of such changes on the performance of the product. A design that undergoes a substantive change becomes a new design requiring retesting. A substantive change is a change which affects the performance of the product in the intended service condition. A substansive change is considered to be any change from the previously qualified configuration or material selection which may affect performance of the product or intended service. This shall be recorded and the manufacturer shall justify whether or not requalification is required. This may include changes in fit, form, function or material. A change in material may not require retesting if the suitability of the new material can be substantiated by other means.

5.1.7.3 Hydrostatic and gas testing

Hydrostatic pressure tests shall be acceptable for all performance verification pressure tests for this part of ISO 13628. Manufacturers may at their option substitute gas test for some or all of the required performance verification pressure test. Hydrostatic and gas performance verification test procedures and acceptance criteria shall meet the requirements set forth in 5.4.

5.1.7.4 Hydrostatic pressure cycling tests

Table 3 lists equipment which must be subjected to repetitive hydrostatic (or gas if applicable) pressure cycling tests to simulate start-up and shutdown pressure cycling which will occur in long term field service. For these hydrostatic cycling tests, the equipment shall be alternately pressurised to the full rated working pressure and then depressurised until the specified number of pressure cycles have been completed. No holding period is required for each pressure cycle. A standard hydrostatic (or gas if applicable) test (see 5.4) shall be performed before and after the hydrostatic pressure cycling test.

5.1.7.5 Load testing

The manufacturer's rated load capacities for equipment in accordance with this part of ISO 13628 shall be verified by either performance verification testing, FEA or classical engineering analysis. If testing is used to verify the design, the equipment shall be loaded to the rated capacity at least three times during the test without deformation to the extent that any other performance requirements are not effected. If engineering analysis is used, the analysis shall be conducted using techniques and programmes which comply with documented industry practice.

Refer to 5.1.3.5 for load testing of unpressurized primary structural components.

5.1.7.6 Minimum and maximum temperature testing

Performance verification tests at rated working pressure or greater shall be performed to confirm the performance of the equipment at a test temperature equal to or less than the minimum rated operating temperature classification, and at a test temperature equal to or greater than the maximum rated operating temperature classification. As an alternative to testing, the manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements at both temperature extremes.

Table 3 — Additional performance verification test requirements

Component	Pressure cycling test	Temperature cycling test	Endurance cycling test
OEC	200	NA	PMR [a] or 3 [b] minimum
Wellhead/tree/spool connectors	3	NA	PMR or 3 [b] minimum
Tubing hanger spools	3	NA	NA
Valves	200	3	200
Valve actuators	200	3	200
Tree cap connectors	3	NA	PMR or 3 [b] minimum
Flowline connectors	200	NA	PMR or 3 [b] minimum
Subsea chokes	200	NA	200
Subsea choke actuators	200	3	200
Subsea wellhead casing hangers	3	NA	NA
Subsea wellhead annulus seal assemblies	3	3	NA
Subsea wellhead tubing hangers	3	3	3 [b]
Mudline tubing hanger spools	3	NA	NA
Mudline wellhead tubing hangers	3	3	3 [b]
Running tools [c]	3	NA	PMR or 3 [b] minimum

[a] PMR which shall not be less than the number of cycles specified.

[b] Seals and other consumable items may be replaced between cycles.

[c] Subsea wellhead running tools are not included (refer to 8.10).

5.1.7.7 Temperature cycling

Table 3 lists equipment which shall be subjected to repetitive temperature cycling tests to simulate start-up and shutdown temperature cycling which will occur in long term field service. For these temperature cycling tests, the equipment shall be alternately heated and cooled to the upper and lower temperature extremes of its rated operating temperature classification as defined in 5.1.7.6. During temperature cycling, rated working pressure shall be applied to the equipment at the temperature extremes with no leaks. Temperature cycling from room temperature to the lower temperature extreme plus cycling from room temperature to the upper temperature extreme may be substituted for temperature cycling directly between the two temperature extremes. As an alternative to testing, the manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements for temperature cycling.

5.1.7.8 Life cycle/endurance testing

Life cycle/endurance testing, such as make-break tests on connectors and operational testing of valves, chokes, and actuators, is intended to evaluate long-term wear characteristics of the equipment tested. Such tests may be conducted at any temperature. Table 3 lists equipment which shall be subjected to extended life cycle/endurance testing to simulate long-term field service. For these life cycle/endurance tests, the equipment shall be subjected to operational cycles in accordance with the manufacturer's performance specifications (i.e. make up to full torque/ break out, open/close under full rated working pressure). Connectors, which include stabs shall include a full disconnect/lift as part of the cycle. Additional specifications for life cycle/endurance testing of the components listed in Table 3 may be found in the equipment specific clauses covering these items (clauses 6 to 11). Secondary functions, such as connector secondary unlock, shall be included in this testing.

5.1.7.9 Product family verification

A product of one size may be used to verify other sizes in a product family, providing the following requirements are met. A product family is a group of products for which the design principles, physical configuration, and functional operation are the same, but which may be of differing size. The design stress levels in relation to material mechanical properties must be based on the same criteria for all members of the product family in order to verify designs via this method. Testing of one size of a product family shall verify products one nominal size larger and one nominal size smaller than the tested size. Testing of multiple product sizes also verifies two nominal sizes larger than the smallest item tested and two nominal sizes smaller than the largest item tested. The test product(s) may be used to qualify products of the same family having equal or lower pressure ratings.

a) Nominal sizes for valves, connectors, hangers[a] and packoffs[b] are defined as follows:
46 mm (1 13/16 in), 52 mm (2 1/16 in), 65 mm (2 9/16 in), 78 mm (3 1/16 in or 3 1/8 in), 103 mm (4 1/16 in or 4 1/8 in), 130 mm (5 1/16 in or 5 1/8 in), 179 mm (7 1/16 in), 228 mm (9 in), 279 mm (11 in), 346 mm (13 5/8 in), 425 mm (16 3/4 in), 476 mm (18 3/4 in), 527 mm or 540 mm (20 3/4 in or 21 1/4 in) and 680 mm (26 3/4 in).

b) Nominal sizes for pipes, hangers[a] and packoffs[b] are defined as follows:
52 mm (2 1/16 in), 60 mm (2 3/8 in), 73 mm (2 7/8 in), 89 mm (3 1/2 in), 102 mm (4 in), 114 mm (4 1/2 in), 127 mm (5 in), 140 mm (5 1/2 in), 168 mm (6 5/8 in), 179 mm (7 in), 194 mm (7 5/8 in), 219 mm (8 5/8 in), 244 mm (9 5/8 in), 273 mm (10 3/4 in), 298 mm (11 3/4 in), 340 mm (13 3/8 in), 406 mm (16 in), 473 mm (18 5/8 in) and 508 mm (20 in).

c) Nominal sizes for chokes are defined in 25,4 mm (1,00 in) increments, where the choke size is determined by the maximum orifice configuration (trim).

NOTE The manufacturer may choose either a or b to define hanger and packoff nominal sizes.

5.1.7.10 Documentation

The manufacturer shall document the procedures used and the results of all performance verification tests used to qualify equipment in this part of ISO 13628. The documentation requirements for performance verification testing shall be the same as the documentation requirements for design documentation in 5.1.5. In addition, documentation shall identify the person(s) conducting and witnessing the tests, and the time and place of the testing.

5.2 Materials

5.2.1 General

The material performance, processing and compositional requirements for all pressure-containing and pressure-controlling parts specified in this part of ISO 13628 shall conform to ISO 10423. For purposes of this reference, subsea wellheads and tubing hanger spools shall be considered as bodies.

5.2.2 Material properties

In addition to the materials specified in ISO 10423 other higher strength materials may be used provided they satisfy the design requirements of 5.1 and comply with the manufacturer's written specifications. The Charpy impact values required by ISO 10423 are minimum requirements and higher values may be specified to meet local legislation or user requirements.

5.2.3 Product specification level

The materials used in equipment covered by this part of ISO 13628 shall comply with requirements for PSL 2 and PSL 3 as established in ISO 10423. Material requirements for PSL 3G are the same as for PSL 3.

5.2.4 Corrosion considerations

5.2.4.1 Corrosion from retained fluids

Material selection based upon wellbore fluids shall be made according to 5.1.2.3.

5.2.4.2 Corrosion from marine environment

Corrosion protection through material selection based upon a marine environment shall consider, as a minimum, the following:

— external fluids;

— internal fluids;

— weldability;

— crevice corrosion;

— dissimilar metals effects;

— cathodic protection effects;

— coatings.

5.2.5 Structural materials

Structural components are normally of welded construction using common structural steels. Any strength grade may be used which conforms to the requirements of the design.

5.3 Welding

5.3.1 Pressure-containing/controlling components

All welding on pressure-containing/controlling components shall comply with the requirements of ISO 10423:1994, clause 500, for PSL 2 and PSL 3, as specified. Welding requirements for PSL 3G are the same as for PSL 3.

5.3.2 Structural components

Structural welds shall be treated as nonpressure-containing welds and comply with ISO 10423 or documented structural welding code AWS D1.1.

5.3.3 Corrosion resistant inlays or overlays

Corrosion resistant inlays or overlays shall be made in accordance with ISO 10423.

5.4 Quality control

5.4.1 General

The quality control requirements for equipment specified in this part of ISO 13628 shall conform to ISO 10423.

For those components not covered in ISO 10423, equipment specific quality control requirements shall comply with the purchaser's/manufacturer's written specifications.

5.4.2 Product specification level

Quality control and testing covered by this part of ISO 13628 shall comply with requirements for PSL 2 and PSL 3 as established in ISO 10423. Quality control for PSL 3G shall be the same as for PSL 3, with the exception of pressure testing which shall comply with 5.4.6. In the case of components manufactured from tubulars, ultrasonic inspection shall be performed in accordance with ISO 11960-2.

5.4.3 Structural components

Quality control and testing of welding for structural components shall be as specified for non-pressure-containing welds as established in ISO 10423:1994, Table 605.2.

5.4.4 Lifting devices

Welds on padeyes and other lifting devices attached by welding shall be subjected to either magnetic particle or dye penetrant testing as specified in ISO 10423. In addition local legislation shall be checked for requirements for proof loading certification and the equipment shall meet local legislation.

5.4.5 Hydrostatic testing for PSL 2 and PSL 3 equipment

Procedures for hydrostatic pressure testing of equipment specified in clauses 6 to 11 shall conform to the requirements for PSL 2 or PSL 3 as described in ISO 10423, with the exception that parts may be painted prior to testing.

For all pressure ratings, the hydrostatic body test pressure shall be a minimum of 1,5 times the rated working pressure.

Maximum test pressures for conventional mudline suspension equipment specified in clause 10 shall conform to the requirements described in annex E (E.2).

Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Gas testing is not required for PSL 2 and PSL 3. However, if substituted by the manufacturer, gas tests shall be performed in accordance with 5.4.6 or the manufacturers written specification.

5.4.6 Testing for PSL 3G equipment

5.4.6.1 Drift test

Drift testing shall be in accordance with PSL 3.

5.4.6.2 Pressure testing

5.4.6.2.1 Hydrostatic body and seat test valves and chokes

A hydrostatic body test for and a hydrostatic valve seat test shall be performed prior to any gas testing. The requirements for hydrostatic testing shall be the same as PSL 3.

5.4.6.2.2 Gas body test for assembled valves and chokes

The test shall be conducted under the following conditions:

a) at ambient temperatures;

b) the test medium shall be nitrogen;

c) the test shall be conducted with the equipment completely submerged in a water bath;

d) valves and chokes shall be in the partially open position during testing;

e) the gas body test for assembled equipment shall consist of a single holding period of not less than 15 min, the timing of which shall not start until the test pressure has been reached and the equipment and pressure monitoring gauge have been isolated from the pressure source;

f) the test pressure shall equal the rated working pressure of the equipment.

The special considerations for hydrostatic body tests shall also apply when appropriate to gas seat tests. Refer to ISO 10423.

Acceptance criteria are that there shall be no visible bubbles in the water bath during the holding period.

5.4.6.2.3 Gas seat test — Valves

The gas seat test may be conducted in addition to or in place of the hydrostatic seat test.

The test shall be conducted under the following conditions.

a) Gas pressure shall be applied on each side of gate or plug of bi-directional valves with the other side open to the atmosphere. Unidirectional valves shall be tested in the direction indicated on the body, except for check valves which will be tested from the downstream side.

b) The test shall be conducted at ambient temperatures.

c) The test medium shall be nitrogen.

d) The test shall be conducted with the equipment completely submerged in a bath of water.

e) Testing shall consist of two, monitored, holding periods.

f) The primary test pressure shall equal rated working pressure.

g) The primary test monitored hold period shall be 15 min;

h) Reduce the pressure to zero between the primary and secondary hold points.

i) The secondary test pressure shall be greater than 5 % of and less than 10 % of the rated working pressure.

j) The secondary test monitored hold period shall be 15 min.

k) The valves shall be fully opened and fully closed between tests.

l) Bi-directional valves shall next be tested on the other side of the gate or plug using the same procedure outlined above. Split gate valves may have both seats tested simultaneously.

The special considerations for hydrostatic body tests shall also apply, when appropriate, to gas seat tests.

Acceptance criteria are that there shall be no visible bubbles in the water bath during the holding period.

In this part of ISO 13628, other pressure boundary penetration equipment such as grease/bleeder fittings, which penetrate directly into or communicate with the wellbore, shall be treated as "stems" as specified in ISO 10423.

5.4.7 Cathodic protection

Electric continuity tests shall be performed to prove the effectiveness of the cathodic protection system. If the electrical continuity is not obtained, earth cabling shall be incorporated in the ineffective areas.

5.5 Equipment marking

5.5.1 General

Equipment that meets the requirements of this part of ISO 13628 shall be marked "ISO 13628-4" in accordance with ISO 10423.

All equipment marked "ISO 13628-4" shall, also, be marked with the following minimum information: part number, manufacturer name or trademark. Refer to ISO 10423:1994, Table 701.1, for metallic marking locations. In addition subsea tree assemblies which meet all of the requirements in clause 6 shall also be marked as "ISO 13628-4" tree assemblies.

Equipment shall be marked in either metric units or imperial units (the units shall be marked together with the numbers). Reference is also made to ISO 13628-1.

5.5.2 Padeyes

Lifting capacity of all padeyes and lifting points shall be clearly marked, identifying the safe working load, the angle of lift, and the number of lifting points.

EXAMPLE: 4 padeyes, 230 kN (51 706 lbf) capacity each, no angle limitation, total capacity of 920 kN (206 824 lbf).

Stamp: 4 x

SWL 230 kN (51 706 lbf)

0° – 90°

Local legislation may require that the expiry date of lifting certificates also be marked on the equipment.

5.5.3 Other lifting devices

The rated lifting capacity of other lifting devices such as tools, as determined in 5.1.3.7, shall be clearly marked in a position visible when the lifting device is in the operating position. In addition, this equipment shall be marked with rated working pressure, manufacturer's name or trademark and model or part number.

5.5.4 Temperature ratings

Subsea equipment manufactured in accordance with 5.1.2.2.1 shall be stamped "2 °C – 120 °C" ("35 °F – 250 °F").

Subsea equipment manufactured in accordance with 5.1.2.2.2 shall be stamped "2 °C – 65 °C (120 °C)" ("35 °F – 150 °F (250 °F)") where the "(120)" "(250)" refers to the maximum retained fluid temperature.

Subsea equipment manufactured in accordance with 5.1.2.2.3 shall be stamped as follows:

EXAMPLE: Low temperature rating of 2 °C (35 °F) and high temperature rating of 175 °C (350 °F) Stamp: 2 °C – 175 °C (35 °F – 350 °F)

5.6 Storing and shipping

5.6.1 Draining after testing

All equipment shall be drained and lubricated in accordance with the manufacturer's written specification after testing prior to storage or shipment.

5.6.2 Rust prevention

Prior to shipment, parts and equipment shall have exposed metallic surfaces (except those specially designated such as anodes or nameplates) either protected with a rust preventive coating which will not become fluid at temperatures less than 50 °C (125 °F), or filled with a compatible fluid containing suitable corrosion inhibitors in accordance with the manufacturer's written specification. Equipment already coated, but showing damage after testing, should undergo coating repair prior to storage or shipment as specified in 5.1.4.8.

5.6.3 Sealing surface protection

Exposed seals and seal surfaces, threads, and operating parts shall be protected from mechanical damage during shipping. Equipment or containers shall be designed such that equipment does not rest on any seal or seal surface during shipment or storage.

5.6.4 Loose seals and ring gaskets

Loose seals, stab subs and ring gaskets shall be individually boxed or wrapped for shipping and storage.

5.6.5 Elastomer age control

The manufacturer shall document instructions concerning the proper storage environment, age control procedures and protection of elastomer materials.

5.6.6 Hydraulic systems

Prior to shipment, the total shipment including hydraulic lines shall be flushed and filled in accordance with the manufacturer's written specification. Exposed hydraulic end fittings shall be capped or covered.

5.6.7 Electrical/electronic systems

The manufacturer shall document instructions concerning proper storage and shipping of all electrical cables, connectors and electronic packages (pods).

5.6.8 Shipments

For shipment, units and assemblies should be securely crated or mounted on skids so as to prevent damage and to facilitate sling handling. All metal surfaces should be protected by paint or rust preventative, and all flange faces, clamp hubs and threads should be protected by suitable covers.

Consideration will be given to transportation and handling onshore as well as offshore. Where appropriate equipment will be supplied with removable bumper bars or transportation boxes/frames.

All assemblies and equipment which will be handled between supply boat and rig, may have dedicated lifting equipment (sling assemblies, etc.) which complies with local Legislation. All packages exceeding 100 kN (22 481 lbf) will have pad eyes for handling and sea fastening. If these pad eyes are to be used for sea fastening only, they shall be clearly marked with "SEA FASTENING ONLY". All other equipment not suitable for shipping in baskets or containers, shall be furnished with facilities for sea fastening as appropriate.

5.6.9 Assembly, installation and maintenance instructions

The manufacturer shall document instructions concerning field assembly, installation and maintenance of equipment. These shall address safe operating procedures and practices.

6 Specific requirements — Subsea tree assemblies

6.1 Design

6.1.1 General

6.1.1.1 Introduction

This subclause provides specific requirements for the equipment covered in clause 7, to configure the conventional or horizontal subsea tree. Subsea tree assembly configurations vary depending on wellhead type, service, well shut in pressure, water depth, reservoir parameters, environmental factors and government legislation for the area in which the tree is to be installed. As such, the subsea tree configuration requirements are not specified in this subclause. Governmental regulations of the country in which the equipment is to be installed shall be carefully checked to determine the pressure barrier requirements before designing the system. The number of potential leak paths should be minimized during system design.

6.1.1.2 Requirements

Equipment used in the assembly of the subsea tree which is covered in clause 7 shall meet the requirements of clause 7.

Equipment used in the assembly of the subsea tree which is not covered in clause 7 shall comply with the purchaser's/manufacturer's written specifications.

6.1.1.3 Handling and installation

Structural analysis shall be performed to ensure that structural failure will occur at a point above the tree re-entry spool, leaving the tree in a safe condition, in the event of a drive off before the tree running tool/EDP can be disconnected.

The design of the subsea tree assembly shall consider the ease of handling and installation. All equipment assemblies shall be balanced. The use of balance weights should be minimised to keep shipping weight to a minimum and the location of balance weights should be carefully chosen so that observation/access by diver/ROV is not compromised.

6.1.1.4 Orientation and alignment

The design shall pay particular attention to the orientation and alignment between equipment packages. The manufacturer shall conduct tolerance and stack-up analysis to ensure that trees will engage tubing hangers, wellheads, guidebases, tree running tools will engage re-entry spools, caps will engage re-entry spools etc. These studies shall take into account external influences such as flowline forces, temperature, currents, riser offsets etc. Equipment shall be suitably aligned and orientated before stab subs enter their sealing pockets. Where feasible during factory acceptance testing, calculations shall be verified by realistic testing.

6.1.1.5 Rating

The PSL designation, pressure rating, temperature rating and material class assigned to the subsea tree assembly, shall be determined by the minimum rating of any single component normally exposed to wellbore fluid used in the assembly of the subsea tree.

6.1.1.6 Interchangeability

Components and sub assemblies for different arrangements of subsea tree configurations shall be interchangeable if functional requirements permit this. Examples are change out of tree connector to suit different wellhead profiles, change out of wing valve arrangements for different services such as production, injection etc. and interchangeability of spares.

Interchangeability between trees, tubing hangers, caps, tool interfaces, etc. shall be assured by the design and demonstrated during FAT. Where logistics prevents this, then it should be proven by the use of test fixtures. Integration testing is outside the scope of this part of ISO 13628.

6.1.1.7 Safety

Safe access for personnel on to equipment packages during testing, inspection, maintenance, preparation for installation, or other tasks should be considered as part of the design. Where necessary ladders shall be furnished. These may be removable. Handrails and hand holds should be considered where personnel are required to work on top of equipment packages. Where assemblies are stacked, the ladders should be positioned to facilitate safe transfer from one assembly to the other. The system must also be in accordance with local legislation.

6.1.2 Tree valving

6.1.2.1 Master valves conventional tree

Any valve in the vertical bore of the tree between the wellhead and the tree side outlet shall be defined as a master valve. A conventional subsea tree shall have one or more master valves in the vertical production (injection) bore and vertical annulus when applicable, at least one of which shall be a power operated fail closed valve.

6.1.2.2 Master valves horizontal tree

The inboard valve branching horizontally off the tree between the wellhead and the production (injection) flowbore or the inboard valve on the bore into the annulus below the tubing hanger, shall be defined as a master valve. A horizontal subsea tree shall have at least one master valve on each of the above bores which shall be a power operated fail closed valve.

6.1.2.3 Wing valves conventional tree

A wing valve is any valve in the subsea tree assembly that controls either the production (injection) or annulus flowpath and is not in the vertical bore of the tree. Each side outlet for production (injection) and annulus flow path of the subsea tree will have a wing valve when required by legislation or project specific requirements with respect to operational/process and/or well intervention requirements.

6.1.2.4 Wing valves horizontal tree

The horizontal subsea tree will have such a valve down stream of the master valve in both the production (injection) flowbore and the annulus flowbore when required by legislation or project specific requirements with respect to operational/process and/or well intervention requirements.

6.1.2.5 Swab closures, conventional and horizontal tree

Any vertical bore that passes through the subsea tree assembly, which could be used in workover operations, shall be equipped with at least one pressure-controlling (swab) closure. The swab closure is a device that allows vertical access into the tree, but is not open during production flow. Swab closures may be caps, stabs, tubing plugs or valves. Removal or opening of the swab closure shall not result in any diametrical restriction through the vertical bore of the conventional tree.

Swab valves may be either manual or power operated. When power operated they shall only be operable from the workover system.

If no other power-operated fail closed valve is in the vertical annulus bore of the tree, then the swab closure for that bore shall be a power operated fail closed valve.

6.1.2.6 Workover valve horizontal tree

Any side penetration that gives access into the vertical bore shall be equipped with at least one valve. The valve shall be a power operated fail closed valve.

6.1.2.7 Crossover valves

A crossover valve is an optional valve that, when opened, allows communication between two tree paths that are normally isolated.

6.1.2.8 Tree assembly pressure closures

The subsea tree assembly shall meet the pressure-closure requirements of governmental regulations for the country in which it is to be installed. This part of ISO 13628 is only concerned with the pressure-closure requirements contained within the subsea tree assembly. Other industry recognised pressure closures contained in the total system, such as downhole SCSSVs or flowline valves are beyond the scope of this part of ISO 13628. It is not intended that multiple pressure closure requirements of the subsea tree assembly replace the need for other system pressure closures.

6.1.2.9 Production (injection) and annulus flow paths

The minimum requirement for valving in the production (injection) and annulus flowpaths to maintain the subsea tree as a barrier element, is one power operated fail closed master valve in the production (injection) bore and one power operated fail closed master valve in the annulus bore. Other valves as described in this subclause shall be added when required by legislation or project requirements with respect to operational/process and/or well intervention requirements.

A schematic for a typical conventional dual bore subsea tree is illustrated in Figure 2, whilst Figure 3 illustrates a conventional single bore tree with a tubing spool. Figure 4 illustrates a typical horizontal subsea tree.

6.1.2.10 Production and annulus bore penetrations

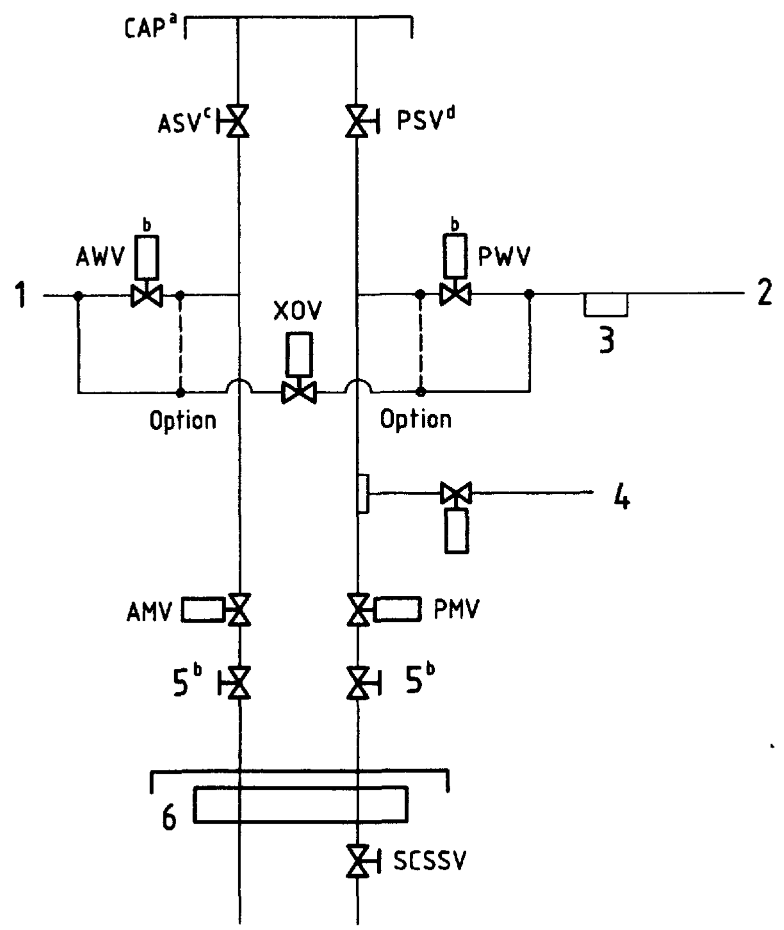
Any penetrations into the production (injection) flow stream of the subsea tree shall be made downstream the lowest (or innermost) master valve. Flanges, clamp hubs or other end connections meeting the requirements of clause 7, as applicable, shall be used to provide connections for the penetrations to the tree.

There shall be at least two testable fail closed pressure closures, one of which shall be a power operated fail closed valve, between the wellhead and any penetration leading into either the production (injection) or annulus path of the tree or tubing spool. If the master valve is fail closedd it may be classed as one of the fail closed pressure closures.

Flow-closed check valves are acceptable as fail-closed closures for monitoring or chemical injection penetration lines that are 25,4 mm (1,00 in) nominal diameter or smaller. The check valve may be inboard or outboard of the fail closed valve.

Devices that terminate directly on the tree such as transducers do not require penetration valving, provided there is a pressure closure between the tree bore and the environment. These devices shall comply with clause 5, if there is no power-operated fail-close valve between the penetration and the wellhead.

Figure 5 illustrates minimum configurations which meet the requirements of this subclause.



ASV	Annulus swab valve
AMV	Annulus master valve
AWV	Annulus wing valve
PMV	Production master valve
PSV	Production swab valve
PWV	Production wing valve
XOV	Crossover valve

Key

1 Annulus

2 Production line

3 Penetration (Welded boss)

4 Penetration (Flange with one pressure-controlled device)

5 Optional master (manual or hyd.)

6 Hanger

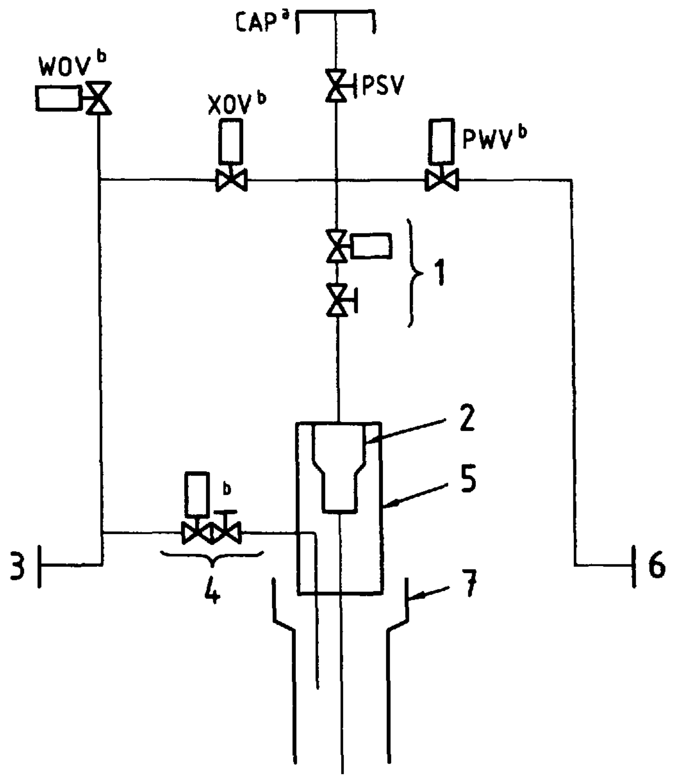
a Non-pressure-containing tree cap may be considered when swab valve or other closures are included

b To be included when required by legislation or by operational and/or intervention requirements

c Manual or fail closedd

d Manual or fail-closed or optional plug

Figure 2 — Example of dual bore tree on subsea wellhead

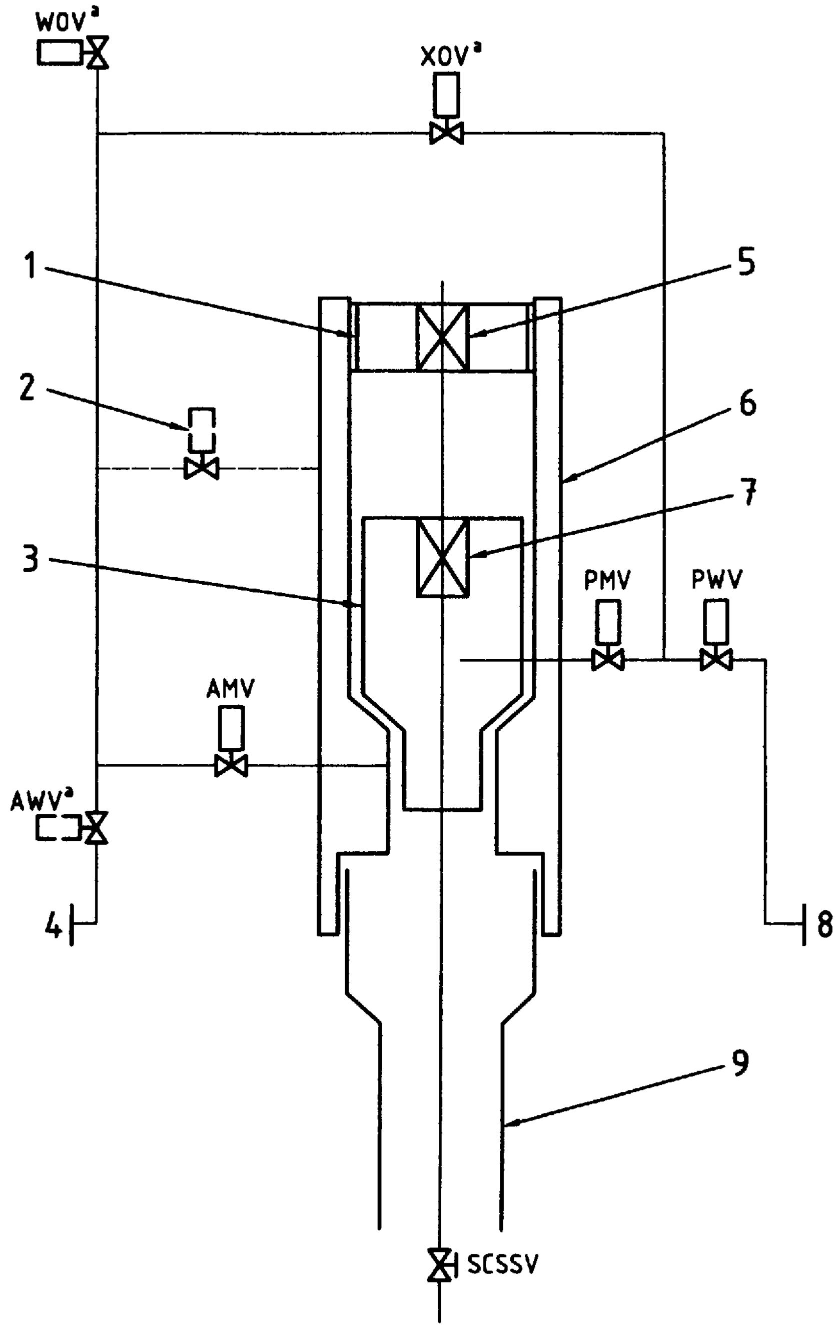


PSV Production swab valve
XOV Crossover valve
WOV Workover valve

Key

1 Production master valve
2 Tubing hanger
3 Annulus/service line (optional)
4 Annulus valves
5 Tubing spool
6 Production line
7 Mudline suspension wellhead
a Non-pressure-containing tree cap may be considered when swab valve or other closures are included
b To be included when required by legislation or by operational and/or intervention requirements

Figure 3 — Example of single bore tree on mudline tie-back

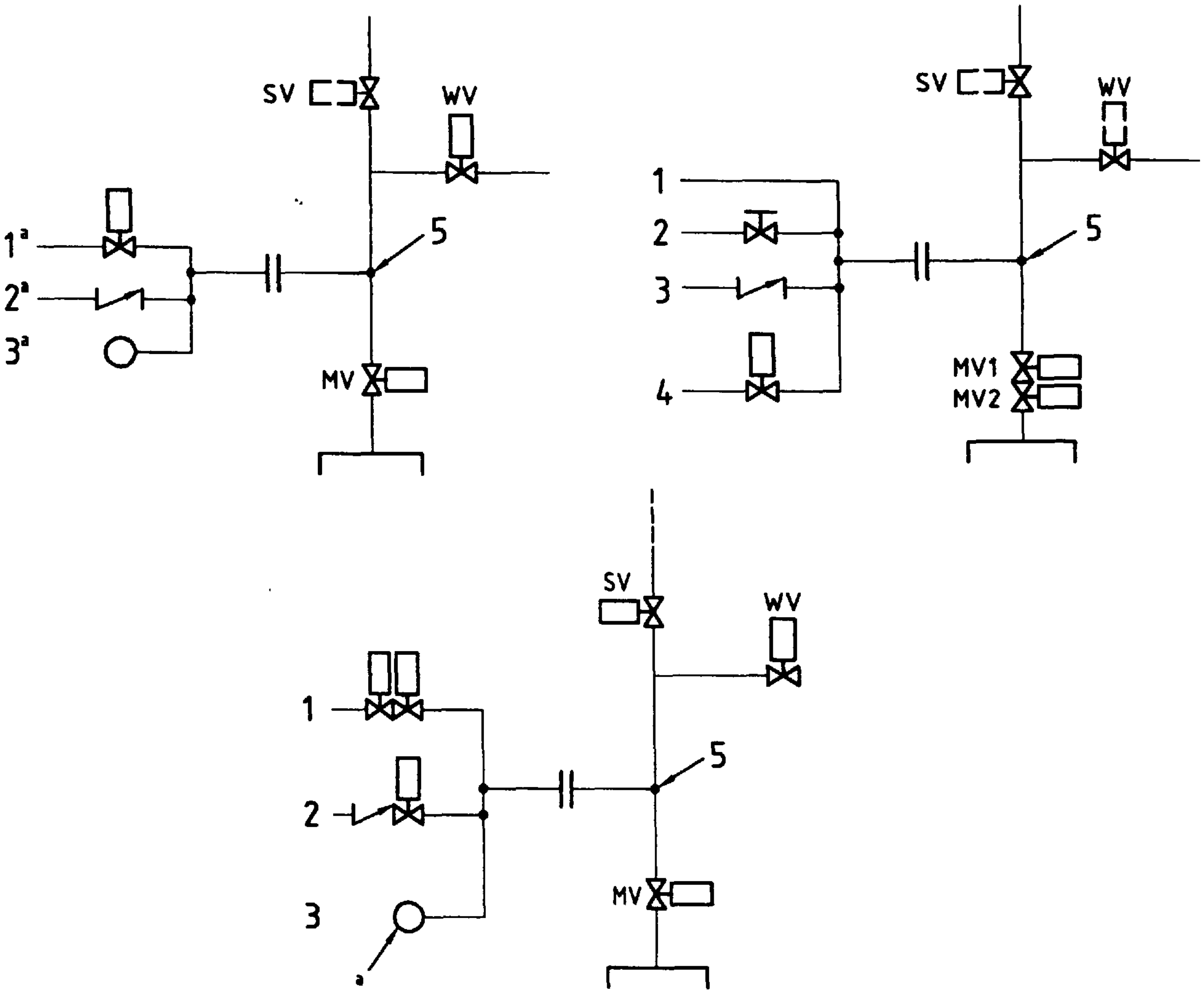


AMV Annulus master valve
AWV Annulus wing valve
PMV Production master valve
PWV Production wing valve
WOV Workover valve
XOV Crossover valve

Key

1 Pressure containing cap
2 Alternative WOV
3 Tubing hanger
4 Annulus/service line (optional)
5 Closure/access device (optional)
6 Horizontal tree
7 Closure/access device
8 Production line
9 Wellhead
[a] To be included when required by legislation or by operational and/or intervention requirements

Figure 4 — Example of horizontal tree on subsea wellhead or drill-through mudline wellhead



ey

1
2
3
4 } Options

5 Flange or clamp hub

a Complies with 5.1.3.3.

MV Master valve
SV Swab valve
WV Wing valve

NOTE The dotted inclusions are optional.

Figure 5 — Examples of tree bore penetrations

6.1.2.11 SCSSV control line penetrations

At least one pressure-controlling closure shall be used at all SCSSV control line penetrations that pass through either the tree or tubing spool. Manual valves (diver/ROV operated) are acceptable closing devices.

Any remotely operated closure device used in the SCSSV control line circuit shall be designed such that it does not interfere with the closure of SCSSV.

Check valves shall not be used anywhere in the SCSSV circuit if their closure could prevent venting down of the control pressure.

...e right-hand side of Figure 1 illustrates typical subsea tree valving for SCSSV circuits that meet the requirements ... this subclause.

6.1.2.12 Downhole chemical injection line penetrations

Certain countries require that the subsea tree assembly shall provide for two fail closed valves in all chemical injection lines which pass through the tubing hanger. Flow-closed check valves are acceptable as one of the fail closed valves, for line sizes of 25,4 mm (1,00 in) nominal diameter or smaller. At least one of the fail closed valves shall be a power operated fail closed valve. The left side of Figure 1 illustrates typical subsea tree valving for the above. The check valve may be inboard or outboard of the fail closed valve. Flanges, clamp hubs or OECs meeting the requirements of clause 7, as applicable, shall be used to provide connections for the penetrations to the tree.

6.1.2.13 Pressure monitoring/test lines.

On lines such as connector cavity test lines, manual isolation valves are acceptable closure devices.

6.1.2.14 Compensating barrier

Where a compensating barrier is used to exclude seawater from the actuator and balance hydrostatic pressure it shall be sized to accomodate 120 % of the swept volume. A means (such as check valves) should be included in the circuit to prevent hydraulic lock.

6.2 Testing of subsea tree assemblies

6.2.1 Performance verification testing

There are no performance verification testing requirements for subsea tree assemblies. However, all parts and equipment covered in clause 7 used in the assembly of subsea trees shall conform to its applicable performance verification testing requirements.

6.2.2 Factory acceptance testing

The subsea tree assembly shall be tested (including drift test) in accordance with ISO 10423. For TFL applications, the subsea tree assembly shall be drift tested in accordance with ISO 13628-3.

The subsea tree assembly shall be factory acceptance tested in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture that simulates the applicable guidebase, wellhead and tubing hanger interfaces.

NOTE Integration testing of total system is beyond the scope of this part of ISO 13628.

6.3 Marking

The subsea tree assembly shall be tagged with a nameplate labelled as "Subsea Tree Assembly", located on the master valve or tree valve block, and contain the following information as a minimum:

— name and location of assembler/date;

— PSL designation of assembly;

— rate working pressure of assembly;

— temperature rating of assembly;

— material class of assembly;

— drift test/date;

— ISO 13628-4;

— identification data.

6.4 Storing and shipping

No part or equipment on the assembled subsea tree shall be removed or replaced during storage or shipping unless the tree is appropriately and successfully retested and then re-tagged. (i.e. testing of affected components only, required).

The shipping weight of the subsea tree including balance weights, shall be kept to a minimum. In many cases maximum lift weight may be restricted by rig crane limitations or local legislation. A maximum 300 kN (67 442 lbf) is often specified. Each shipping package may be supplied with lifting slings certified according to local legislation.

7 Specific requirements — Subsea tree related equipment and sub-assemblies

This clause provides specific requirements for equipment related to subsea trees, which is to be configured in accordance with the specific requirements of clause 6. Refer to clause 12 for purchasing guide lines.

7.1 Flanged end and outlet connections

7.1.1 General — Flange types

This subclause controls the ISO (API) type end and outlet flanges used on subsea completions equipment. Table 4 lists the types and sizes of flanges covered by this part of ISO 13628.

Table 4 — Rated working pressures and size ranges of API flanges

Rated working pressure		Flange size range									
								Segmented			
		Type 17SS		Type 17SV		Type 6BX		Dual		Triple or quadruple	
MPa	(psi)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)
34,5	(5 000)	52 to 279	(2 1/16 to 11)	52 to 279	(2 1/16 to 11)	346 to 540	(13 5/8 to 21 1/4)	35 to 103 x 108	(1 3/8 to 4 1/16 x 4 1/4)	46 to 103	(1 13/16 to 4 1/16 x 4 1/4)
69,0	(10 000)	-	-	46 to 279	(1 11/16 to 11)	46 to 540	(1 11/16 to 21 1/4)	-	-	-	-
103,5	(15 000)	-	-	-	-	46 to 496	(1 11/16 to 18 3/4)	-	-	-	-

Standard flanges for subsea completion equipment with working pressures of 34,5 MPa (5 000 psi) and below in nominal sizes of 51 mm (2 in) through 279 mm (11 in) shall be type 17SS flanges as defined in 7.1.2.2. Type 17SS flanges are based on type 6B flanges, as defined in ISO 10423, modified slightly to be consistent with established subsea practice. The primary modifications are substitution of BX type ring gaskets for subsea service and slight reductions of through bore diameters on some flange sizes. Type 17SS flanges have been developed for the nominal sizes and rated working pressures given in Table 4.

Standard flanges for 34,5 MPa (5 000 psi) and below in nominal sizes of 346 mm (13 5/8 in) through 540 mm (21 1/4 in) shall be type 6BX flanges as defined in ISO 10423.

Standard flanges for subsea completions with maximum working pressures of 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) shall be type 6BX flanges as defined in ISO 10423. ISO type flanges for subsea completions may be either integral, blind or weld neck flanges. Threaded flanges, as defined in ISO 10423, shall not be used on subsea completion equipment handling produced fluids except as noted in 7.3.

Segmented flanges for subsea completions shall comply with the specifications for segmented flanges as defined in 7.1.2.4.

Swivel flanges are often used to facilitate subsea flowline connections which are made up underwater. Type 17SV flanges, as defined herein, have been developed as the "standard" swivel flange design for subsea completions in the sizes and working pressures given in Table 4. Type 17SV swivel flanges are designed to mate with standard ISO type 17SS and type 6BX flanges of the same size and pressure rating.

All end and outlet flanges used on subsea completion equipment shall have their ring grooves either manufactured from or inlayed with corrosion resistant material in accordance with 7.1.2.5.5.

7.1.2 Design

7.1.2.1 General

All flanges used on subsea completions equipment shall be of the ring joint type designed for face-to-face make-up. The connection make-up force and external loads react primarily on the raised face of the flange. Therefore, at least one of the flanges in a connection shall have a raised face.

All flanged connections which will be made up underwater in accordance with the manufacturer's written specification shall be equipped with means to vent any trapped fluids. Type SBX and SRX ring gaskets, as shown in Tables 5 and 6, are acceptable means for venting ISO flanges.

Other proprietary flange and seal designs have been developed which eliminate the trapped fluid problem and are therefore well suited for underwater make-up. These proprietary flange and seal designs shall comply with 7.4.

Trapped fluid can also interfere with the proper make-up of studs or bolts installed into blind holes underwater. Means shall be provided for venting such trapped fluid from beneath the studs (such as holes or grooves in the threaded hole and/or the stud).

7.1.2.2 Standard subsea flanges — Working pressures up to 34,5 MPa (5 000 psi) (type 17SS flanges)

7.1.2.2.1 General

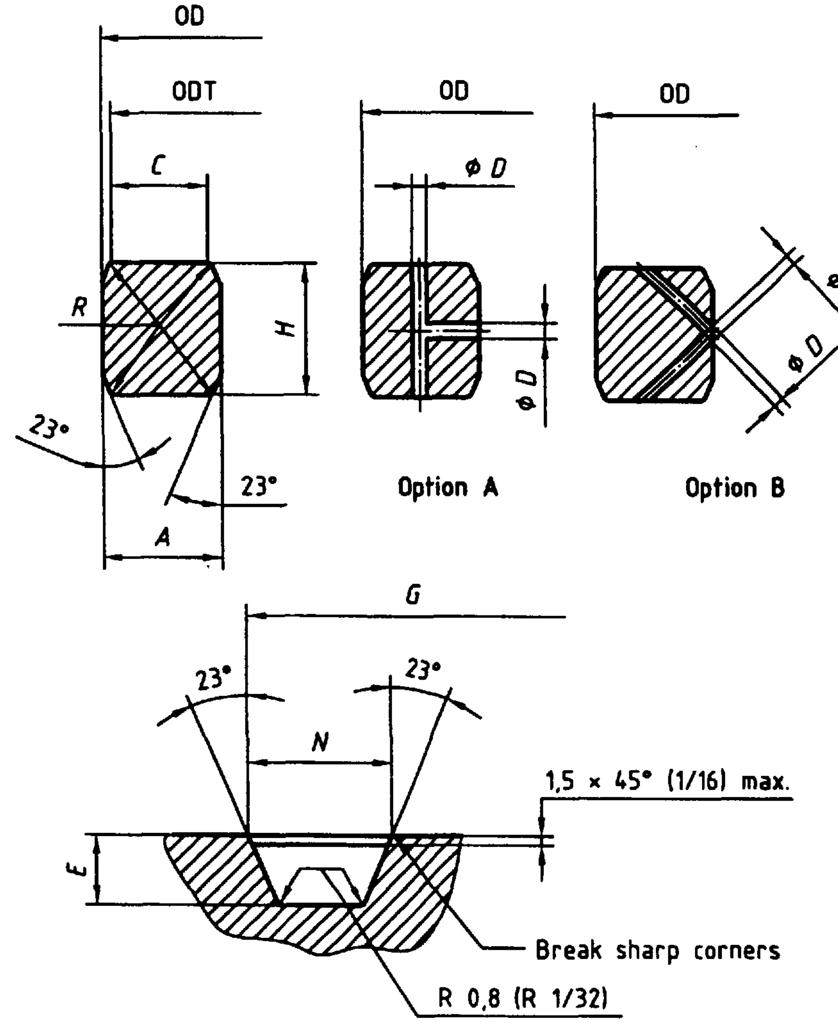
52 mm (2 in) through 279 mm (11 in) type 17SS flange designs are based on type 6B flange designs as defined in ISO 10423, but they have been modified to incorporate type BX ring gaskets (the established practice for subsea completions) rather than type R or RX gaskets. In addition, type 17SS flanges are designed with raised faces for rigid face-to-face make-up.

34,5 MPa (5 000 psi) type 17SS flanges shall be used for all 52 mm (2 in) through 279 mm (11 in) subsea completion ISO type flange applications at or below 34,5 MPa (5 000 psi) working pressure.

346 mm (13 5/8 in) through 540 mm (21 1/4 in) standard subsea flanges for working pressures of 34,5 MPa (5 000 psi) and below shall be type 6BX flanges as defined in ISO 10423.

Table 5 — API type SBX pressure energized ring gaskets

Dimensions in millimetres
(inches in parentheses)



Tolerances

$A\ ^{+0,02}_{0}\left(^{+0,008}_{0}\right)$

$C\ ^{+0,15}_{0}\left(^{+0,006}_{0}\right)$

$D\ ^{0}_{-0,8}\left(^{0}_{-0,03}\right)$

$E\ ^{+0,8}_{0}\left(^{+0,02}_{0}\right)$

$F\ ^{+0,2}_{0}\left(^{+0,008}_{0}\right)$

$H\ ^{+0,2}_{0}\left(^{+0,008}_{0}\right)$

$OD\ ^{+0,5}_{0}\left(^{+0,020}_{0}\right)$

P (average pitch diameter of groove) 0,1 (0,005)

R_1 (radius of ring) 0,5(0,02)

R_2 (radius of groove) max.

angle 23° ± 1/2°

NOTE 1 Radius *R* shall be 8 % to 12 % of the gasket height *H*.

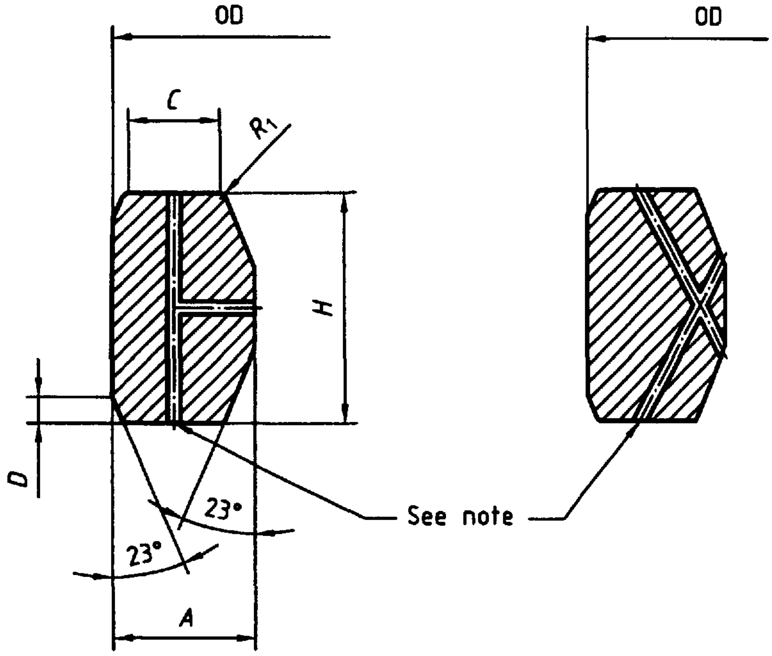
NOTE 2 Two pressure passage holes in the SBX ring cross section prevent pressure lock when connections are made up underwater. Two options are provided for drilling the pressure passage holes.

Ring number	Nominal size		Outside diameter of ring		Height of ring[a]		Width of ring[a]		Diameter of flat		Width of flat		Hole size		Depth of groove		Outside diameter of groove		Width of groove	
			OD		*H*		*A*		ODT		*C*		*D*		*E*		*G*		*N*	
	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)
SBX 151	46	(1 11/16)	76,40	(3,008)	9,63	(0,379)	9,63	(0,379)	75,03	(2,954)	8,26	(0,325)	1,5	(0,06)	5.56	(0,22)	77,79	(3.062)	11,84	(0,466)
SBX 152	52	(2 1/16)	84,68	(3,334)	10,24	(0,403)	10,24	(0,403)	83,24	(3,277)	8,79	(0,346)	1,5	(0,06)	5,95	(0,23)	86,23	(3.395)	12,65	(0,498)
SBX 153	65	(2 9/16)	100,94	(3,974)	11,38	(0,448)	11,38	(0,448)	99,31	(3,910)	9,78	(0,385)	1,5	(0,06)	6,75	(0,27)	102,77	(4.046)	14,07	(0,554)
SBX 154	78	(3 1/16)	116,84	(4,600)	12,40	(0,488)	12,40	(0,488)	115,09	(4,531)	10,64	(0,419)	1,5	(0,06)	7,54	(0,30)	119,00	(4.685)	15,39	(0,606)
SBX 155	103	(4 1/16)	147,96	(5,825)	14,22	(0,560)	14,22	(0,560)	145,95	(5,746)	12,22	(0,481)	1,5	(0,06)	8,33	(0,33)	150,62	(5.930)	17,73	(0,698)
SBX 156	179	(7 1/16)	237,92	(9,367)	18,62	(0,733)	18,62	(0,733)	235,28	(9,263)	15,98	(0,629)	3,0	(0,12)	11,11	(0,44)	241,83	(9.521)	23,39	(0,921)
SBX 157	228	(9)	294,46	(11,593)	20,98	(0,826)	20,98	(0,826)	291,49	(11,476)	18,01	(0,709)	3,0	(0,12)	12,70	(0,50)	299,06	(11.774)	26,39	(1,039)
SBX 158	279	(11)	352,04	(13,860)	23,14	(0,911)	23,14	(0,911)	348,77	(13,731)	19,86	(0,782)	3,0	(0,12)	14,29	(0,56)	357,23	(14.064)	29,18	(1,149)
SBX 159	346	(13 5/8)	426,72	(16,800)	25,70	(1,012)	25,70	(1,012)	423,09	(16,657)	22,07	(0,869)	3,0	(0,12)	15,88	(0,62)	432,64	(17.033)	32,49	(1,279)
SBX 160	346	(13 5/8	402,59	(15,850)	23,83	(0,938)	13,74	(0,541)	399,21	(15,717)	10,36	(0,408)	3,0	(0,12)	14,29	(0,56)	408,00	(16.063)	19,96	(0,786)
SBX 161	422	(16 5/8)	491,41	(19,347)	28,07	(1,105)	16,21	(0,638)	487,45	(19,191)	12,24	(0,482)	3,0	(0,12)	17,07	(0,67)	497,94	(19.604)	23,62	(0,930)
SBX 162	422	(16 5/8)	475,49	(18,720)	14,22	(0,560)	14,22	(0,560)	473,48	(18,.641)	12,22	(0,481)	1,5	(0,06)	8,33	(0,33)	487,33	(18.832)	17,91	(0,705)
SBX 163	476	(18 3/4)	556,16	(21,896)	30,10	(1,185)	17,37	(0,684)	551,89	(21,728)	13,11	(0,516)	3,0	(0,12)	18,26	(0,72)	563,50	(22.185)	25,55	(1,006)
SBX 164	476	(18 3/4)	570,56	(22,463)	30,10	(1,185)	24,59	(0,968)	566,29	(22,295)	20,32	(0,800)	3,0	(0,12)	18,26	(0,72)	577,90	(22.752)	32,77	(1,290)
SBX 165	540	(21 1/4)	624,71	(24,595)	32,03	(1,261)	18,49	(0,728)	620,19	(24,417)	13,97	(0,550)	3,0	(0,12)	19,05	(0,75)	632,56	(24.904)	27,20	(1,071)
SBX 166	540	(21 1/4)	640,03	(25,198)	32,03	(1,261)	26,14	(1,029)	635,51	(25,020)	21,62	(0,851)	3,0	(0,12)	19,05	(0,75)	647,88	(25.507)	34,87	(1,373)
SBX 169	131,18	(5 1/8)	173,51	(6,831)	15,85	(0,624)	12,93	(0,509)	171,29	(6,743)	10,69	(0,421)	1,5	(0,06)	9,65	(0,38)	176,66	(6.955)	16,92	(0,666)

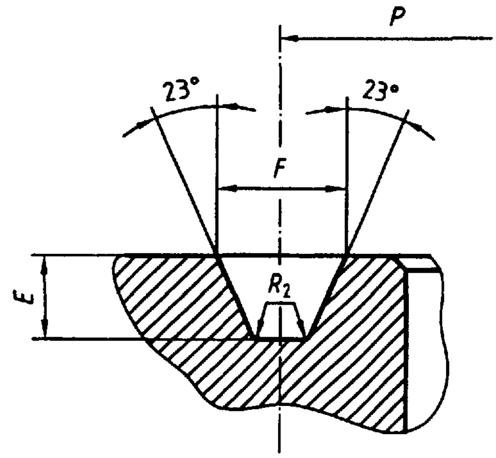
[a] A plus tolerance of 0,2 mm (0,008 in) for width *A* and height *H* is permitted, provided the variation in width or height of any ring does not exceed 0,1 mm (0,004 in) throughout its entire circumference.

Table 6 — API type SRX pressure energized ring gaskets

Tolerances in millimetres
(inches in parentheses)



Option A   Option B



Tolerances

$A\ {}^{+0{,}02}_{0}\left({}^{+0{,}008}_{0}\right)$

$C\ {}^{+0{,}15}_{0}\left({}^{+0{,}006}_{0}\right)$

D 0,5(0,02)

$E\ {}^{+0{,}5}_{0}\left({}^{+0{,}02}_{0}\right)$

G (OD of groove) ${}^{+0{,}1}_{0}\left({}^{+0{,}004}_{0}\right)$

$H\ {}^{+0{,}2}_{0}\left({}^{+0{,}008}_{0}\right)$

OD ${}^{0}_{-0{,}15}\left({}^{0}_{-0{,}006}\right)$

ODT (OD of flat) 0,05 (+0,002)

R (radius of ring) See note

angle 23° ± 1/4°

NOTE The two pressure passage holes illustrated in the SRX ring cross section prevent pressure lock when connections are made up underwater. Hole diameter shall be 7 mm (0,06 in). Two options are provided for drilling the pressure passage hole.

Ring number	Pitch diameter of ring and groove P		Outside diameter of ring OD		Width of ring[a] A		Width of flat C		Height of outside bevel D		Height of ring[a] H		Radius in ring R_1		Depth of groove E		Width of groove F		Radius in groove R_2		Approx. distance between made up flanges S
	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in.)	mm	(in.)	mm	(in)	mm	(in)	mm	(in)	
SRX 201	46,04	(1,813)	46,04	(2,026)	5,74	(0,226)	3,20	(0,126)	1,45	(0,057)	11,30	(0,445)	0,5[c]	(0,02)	4,06	(0,16)	5,56	(0,219)	0,8	(0,03)	-
SRX 205	57,15	(2,250)	62,31	(2,453)	5,56	(0,219)	3,05	(0,120)	1,83[b]	(0,072)	11,10	(0,437)	0,5[c]	(0,02)	4,06	(0,16)	5,56	(0,219)	0,5	(0,02)	-
SRX 210	88,90	(3.500)	97,63	(3,844)	9,53	(0,375)	5,41	(0,213)	3,18[b]	(0,125)	19,05	(0,750)	0,8[c]	(0,03)	6,35	(0,25)	9,53	(0,375)	0,8	(0,03)	-
SRX 215	130,18	(5,125)	140,89	(5,547)	11,91	(0,469)	5,33	(0,210)	4,24[b]	(0,167)	25,40	(1,000)	1,5[c]	(0,06)	7,87	(0,31)	11,91	(0,469)	0,8	(0,03)	-

[a] A plus tolerance of 0,2 mm (0,008 in) for width A and height H is permitted, provided the variation in width or height of any ring does not exceed 0,1 mm (0,004 in) throughout its entire circumference.

[b] Tolerance on these dimensions is ${}^{0}_{-0{,}4}$ mm $\left({}^{0}_{-0{,}015}\text{ in}\right)$.

[c] Tolerance on these dimensions is ${}^{+0{,}5}_{0}$ mm $\left({}^{+0{,}02}_{0}\text{ in}\right)$.

7.1.2.2.2 Dimensions

7.1.2.2.2.1 Standard dimensions

Dimensions for type 17SS integral flanges shall conform to Table 7 (A).

Dimensions for type 17SS weld neck flanges shall conform to Table 7(B).

Dimensions for type 17SS blind flanges shall conform to Figure 6.

Dimensions for rough machining of BX ring grooves for corrosion-resistant inlays shall conform to Table 8, or other weld preparations may be employed where the strength of the overlay alloy equals or exceeds the strength of the base materials.

Dimensions for type 17SS flange ring grooves shall conform to Table 5.

7.1.2.2.2.2 Integral flange exceptions

Type 17SS flanges used as end connections on subsea completion equipment may have entrance bevels, counterbores or recesses to receive running/test tools, plugs, etc. The dimensions of such entrance bevels, counterbores, and recesses are not covered by this part of ISO 13628 and may exceed the B dimension of the tables. The manufacturer shall ensure that the modified flange designs shall meet the requirements of clause 5.

7.1.2.2.2.3 Threaded flanges

Threaded flanges shall not be used on subsea completions equipment, except as provided in 7.3. Dimensions of threaded flanges, if used, shall comply with ISO 10423.

7.1.2.2.2.4 Weld neck flanges — Line pipe

a) **Bore and wall thickness**: The bore diameter *J* shall not exceed the values given in Table 7. The specified bore shall not result in a weld-end wall thickness less than 87,5 % of the nominal wall thickness of the pipe to which the flange is to be attached.

b) **Weld end preparation**: Dimensions for weld end preparation shall conform to Figure 7.

c) **Taper**: When the thickness at the welding end is at least 2,5 mm (3/32 in) greater than that of the pipe, and the additional thickness decreases the ID, the flange shall be taper bored from the weld end at a slope not exceeding 3 to 1.

Due to smaller maximum bore dimensions, type 17SS weld neck flanges are not intended to be welded to wellhead and completion equipment in this part of ISO 13628. Their purpose is to provide a welding transition between a flange and a pipe. Flanges with larger bores for welding to wellhead and completion equipment may be used providing the neck diameter is designed to compensate for the increased bore diameter. The manufacturer shall ensure that the modified flange designs meet the requirements of 5.1.

7.1.2.2.3 Ring grooves

Corrosion resistant inlayed ring grooves for 52 mm (2 in) through 279 mm (11 in) 17SS flanges shall comply with the requirements given in Table 8 and 5.3.3.

Corrosion-resistant inlays for 346 mm (13 5/8 in) through 540 mm (21 1/4 in), 34,5 MPa (5 000 psi), type 6BX flanges shall comply with the requirements of ISO 10423.

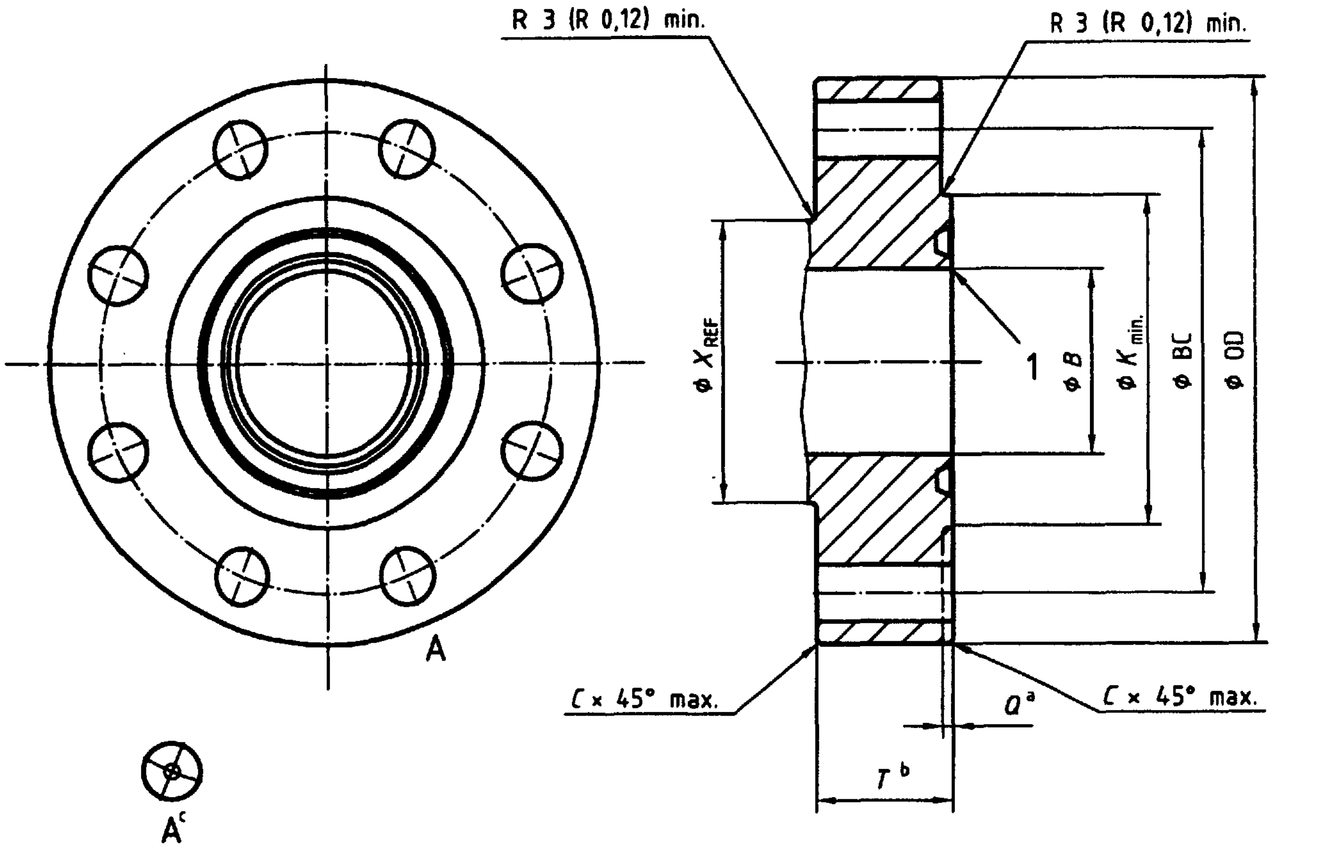
7.1.2.3 Standard subsea flanges — Working pressures 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) (type 6BX)

Standard flanges for use in 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) working pressure subsea completions equipment shall comply with the requirements for type 6BX flanges, as defined in ISO 10423. These flanges are ring joint type flanges, designed for face-to-face make-up. The connection make-up bolting force reacts primarily on the flange face.

Corrosion-resistant inlayed ring grooves for type 6BX flanges shall comply with the requirements of ISO 10423.

Table 7 — (A) Basic flange and bolt dimensions for type 17SS flanges for 34,5 MPa (5 000 psi) rated working pressure

Dimensions in millimetres
(inches in parentheses)



Key

1 Break sharp corner

a $Q = 4{,}61 \pm 0{,}5$ mm (0,18 in ± 0,06 in)

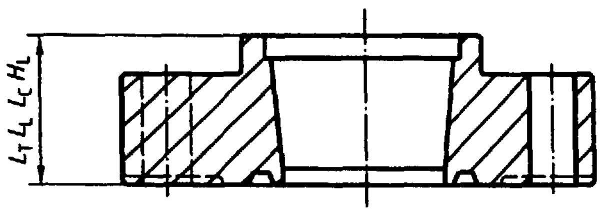
b $T\,^{+3}_{0}\left(^{+0{,}12}_{0}\right)$

c Bolt hole centreline located within 0,8 mm (0,03 in) of theoretical BC and equal spacing

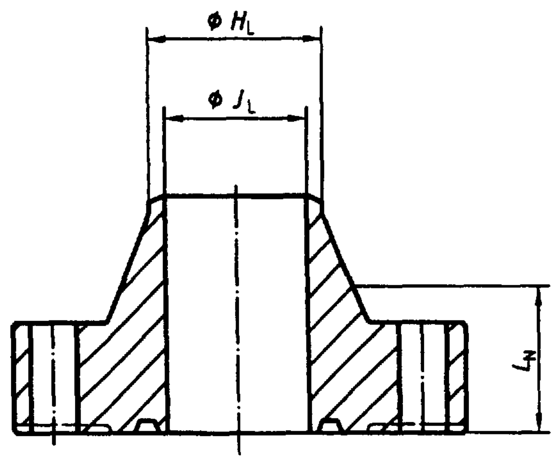
NOTE Ring groove shall be concentric with bore within 0,3 mm (0,010 in) total indicator runout.

Basic flange dimensions														Bolt dimensions													
Nominal size and bore of flange		Max. bore *B*		Outside diameter of flange OD		Tolerance on OD		Max. chamfer *C*		Diameter of raised face *K*		Total thickness of flange *T*		Diameter of hub *X*		Diameter of bolt circle BC		Number of bolts	Diameter of bolts		Diameter of bolt holes		Bolt hole tolerance (see Note)		Length of stud bolts		BX Ring number
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)		mm	(in)	mm	(in)	mm	(in)	mm	(in)	
52	(2 1/16)	53,1	(2,09)	215	(8,50)	±2	(±0,06)	3	(0,12)	128	(5,03)	46,0	(1,81)	104,7	(4,12)	165,1	(6,50)	8	22	(7/8)	26	(1,00)	+2	(+,06)	155	(6,00)	152
65	(2 9/16)	65,8	(2,59)	245	(9,62)	±2	(±0,06)	3	(0,12)	147	(5,78)	49,3	(1,94)	124,0	(4,88)	190,5	(7,50)	8	25	(1)	29	(1,12)	+2	(+,06)	165	(6,50)	153
78	(3 1/8)	78,5	(3,09)	265	(10,50)	±2	(±0,06)	3	(0,12)	160	(6,31)	55,7	(2,19)	133,4	(5,25)	203,2	(8,00)	8	29	(1 1/18)	32	(1,25)	+2	(+,06)	185	(7,25)	154
103	(4 1/16)	103,9	(4,09)	310	(12,25)	±2	(±0,06)	3	(0,12)	194	(7,63)	62,0	(2,44)	162,1	(6,38)	241,3	(9,50)	8	32	(1 1/4)	36	(1,38)	+2	(+,06)	205	(8,00)	155
130	(5 1/8)	131,1	(5,16)	375	(14,75)	±2	(±0,06)	3	(0,12)	238	(9,38)	81,1	(3,19)	196,9	(7,75)	292,1	(11,50)	8	38	(1 1/2)	42	(1,62)	+2	(+,06)	255	(10,00)	169
179	(7 1/16)	180,1	(7,09)	396	(15,50)	±3	(±0,12)	6	(0,25)	272	(10,70)	92,0	(3,62)	228,6	(9,00)	317,5	(12,50)	12	35	(1 3/8)	39	(1,50)	+2	(+,06)	275	(10,75)	156
228	(9)	229,4	(9,03)	485	(19,00)	±3	(±0,12)	6	(0,25)	337	(13,25)	103,2	(4,06)	292,1	(11,50)	393,7	(15,50)	12	42	(1 5/8)	45	(1,75)	+2,5	(+,09)	306	(12,00)	157
279	(11)	280,2	(11,03)	585	(23,00)	±3	(±0,12)	6	(0,25)	418	(16,25)	119,2	(4,69)	368,3	(14,50)	482,6	(19,00)	12	48	(1 7/8)	50	(2,00)	+2,5	(+,09)	350	(13,75)	158
NOTE Minimum bolt hole tolerance is ± 0,5 mm (0,02 in).																											

Table 7— (B) Hub and bore dimensions for type 17SS flanges for 34,5 MPa (5 000 psi) rated working pressure

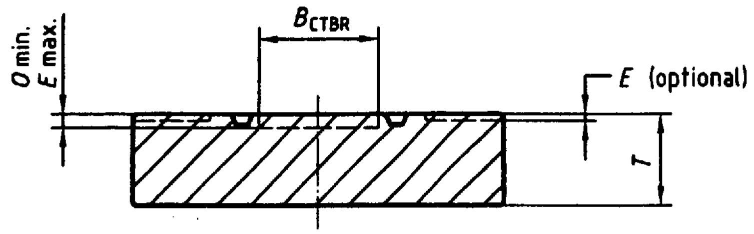


Threaded flange



Weld neck line pipe flange

Hub and bore dimensions															
Nominal size and bore of flange		Hub length Threaded line pipe flange		Hub length Threaded casing flange		Hub length Tubing flange		Hub length Welding neck line pipe flange		Neck diameter Welding neck line pipe flange		Tolerance		Maximum bore of welding neck flange	
		L_L		L_C		L_T		L_N±2(0,06)		H_L		H_L		J_L±0,7(0,03)	
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)
52	(2 1/16)	65,1	(2,56)			65,1	(2,56)	109,5	(4,31)	60,5	(2,38)	+2 −0,7	(+0,09 −0,03)	43,0	(1,69)
65	(2 9/16)	71,4	(2,81)			71,4	(2,81)	112,8	(4,44)	73,2	(2,88)	+2 −0,7	(+0,09 −0,03)	54,1	(2,13)
98	(3 1/8)	81,1	(3,19)			81,1	(3,19)	125,5	(4,94)	88,9	(3,50)	+2 −0,7	(+0,09 −0,03)	66,5	(2,62)
103	(4 1/16)	98,6	(3,88)	98,6	(3,88)	98,6	(3,88)	131,9	(5,19)	114,3	(4,50)	+2 −0,7	(+0,09 −0,03)	87,4	(3,44)
130	(5 1/8)	112,8	(4,44)	112,8	(4,44)			163,6	(6,44)	141,2	(5,56)	+2 −0,7	(+0,09 −0,03)	109,5	(4,31)
179	(7 1/16)	128,6	(5,06)	128,6	(5,06)			181,1	(7,13)	168,4	(6,63)	+4 −0,7	(+0,16 −0,03)	131,0	(5,19)
228	(9)	154,0	(6,06)	154,0	(6,06)			228,8	(8,81)	219,2	(8,63)	+4 −0,7	(+0,16 −0,03)	173,0	(6,81)
279	(11)	170,0	(6,69)	170,0	(6,69)			265,2	(10,44)	273,1	(10,75)	+4 −0,7	(+0,16 −0,03)	215,9	(8,50)



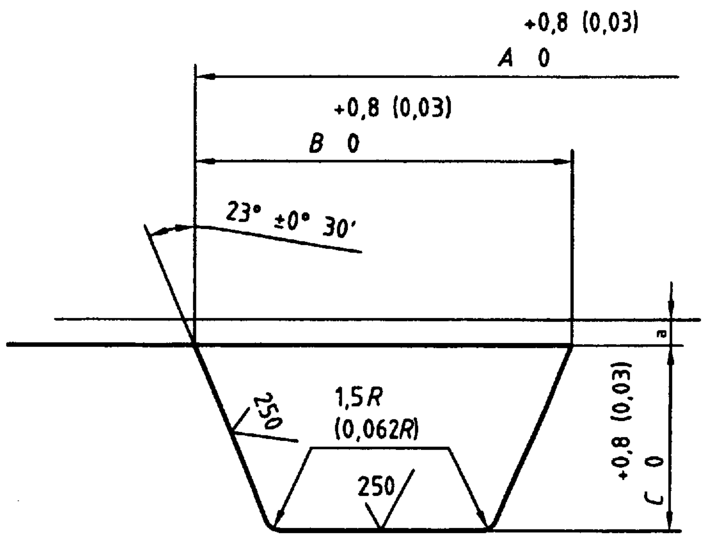
NOTE 1 Raised face and/or counterbore (CTBR) are optional.

NOTE 2 Refer to Table 5 for dimensions B and T and for dimensions not shown. For dimension E, refer to Table 9.

Figure 6 — Type 17SS blind flange

Table 8 — Rough machining detail for corrosion resistant API ring groove

Dimensions in millimetres
(inches in parentheses)



[a] Allow 3,2 mm (1/8 in) or greater for final machining of overlay.

Ring number	Outside diameter of groove A		Width of groove B		Depth of groove C	
	mm	(in)	mm	(in)	mm	(in)
BX-152	95,0	(3,72)	19,5	(0,77)	10,0	(0,38)
BX-153	111,5	(4,38)	21,5	(0,83)	10,5	(0,41)
BX-154	127,5	(5,01)	22,5	(0,88)	11,5	(0,44)
BX-155	159,5	(6,26)	25,0	(0,97)	12,0	(0,47)
BX-156	250,5	(9,85)	31,0	(1,20)	15,0	(0,58)
BX-157	307,5	(12,10)	34,0	(1,32)	16,5	(0,64)
BX-158	366,0	(14,39)	36,5	(1,42)	18,0	(0,70)
BX-169	185,0	(7,285)	23,9	(0,942)	13,2	(0,52)

Ring number	Outside diameter of groove A		Width of groove B		Depth of groove C	
	mm	(in)	mm	(in)	mm	(in)
R-201	59,94	(2,36)	12,7	(0,50)	7,62	(0,30)
R-205	71,12	(2,80)	12,7	(0,50)	10,67	(0,42)
R-210	106,68	(4,20)	16,76	(0,66)	9,91	(0,39)
R-215	150,39	(5,92)	19,05	(0,73)	11,43	(0,45)

Dimensions in millimetres
(inches in parentheses)

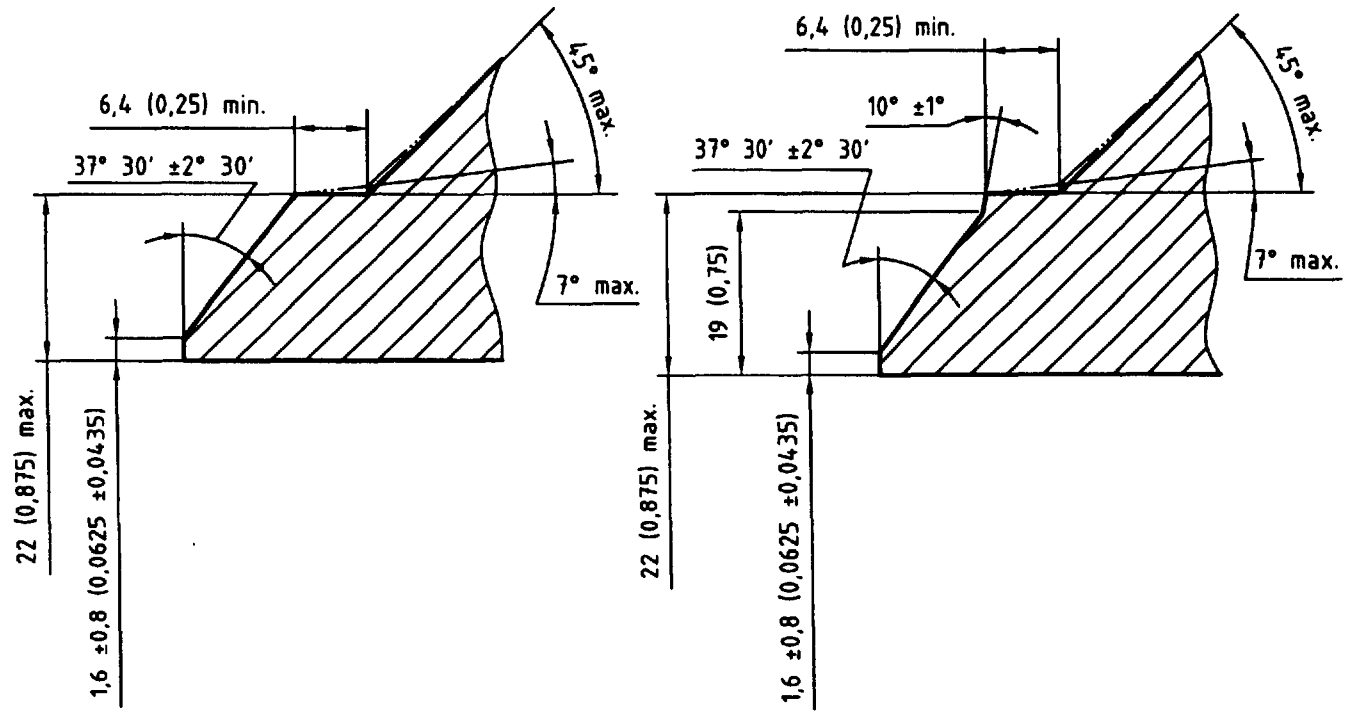


Figure 7 — Weld end preparation for type 17SS and 17SV weld neck flanges

7.1.2.4 Segmented flanges — Working pressure 34,5 MPa (5 000 psi)

Segmented flanges should not be used except where closely spaced multiple connections do not permit the use of full size standard flanges. If ISO 10423 segmented flanges are used, there shall be at least two pressure controlling valves between the segmented flange and the wellhead. Segmented flanges for use on subsea completion equipment shall comply with the requirements of ISO 10423. Segmented flanges for use on subsea completion equipment which comply with the sections requirements of clause 5 and 7.4 do not require the use of two pressure-controlling valves between the segmented flange and the wellhead. These flanges are ring joint type flanges, designed for face-to-face make-up. The connection make-up bolting force reacts primarily on the flange face.

Note that ISO 10423 segmented flanges are not recommended for hydrogen sulfide service.

Segmented flanges shall not be used for applications involving external bending moments unless auxiliary support is provided to isolate the flange from the external loads.

The large angular rotations often required to align mating segmented flanges may induce excessive torsional loads which could damage flexible piping, see ISO 13628-2. If segmented flanges are used with flexible piping, the loads acting on these flanges and flexible piping shall not exceed the limits established by their respective manufacturers.

Note that ISO 10423 segmented flanges use type RX or SRX gaskets. Since RX ring gaskets are not vented and could trap fluid during make up, type SRX gaskets shall be used with segmented flanges which, in accordance with the manufacturer's written specifications, will be made up subsea.

Corrosion-resistant inlayed ring grooves are not allowed for segmented flanges, see ISO 10423. Therefore, segmented flanges must be manufactured from corrosion-resistant materials.

7.1.2.5 Swivel flanges — Working pressures 34,5 MPa (5 000 psi) or 69,0 MPa (10 000 psi) (type 17SV)

7.1.2.5.1 General

Type 17SV flanges are multiple-piece assemblies in which the flange rim is free to rotate relative to the flange hub. A retainer groove is provided on the neck of the hub to allow installation of a snap wire of sufficient diameter to hold the ring on the hub during storage, handling and installation. Type 17SV flanges may be used on subsea completions equipment where it is difficult or impossible to rotate either of the flange hubs to align the mating bolt holes. Type 17SV flanges mate with standard type 6BX and 17SS flanges of the same size and pressure rating.

Type 17SV swivel flanges are of the ring joint type and are designed for face-to-face make-up. The connection make-up bolting force reacts primarily on the flange face.

7.1.2.5.2 Dimensions

Dimensions for type 17SV integral flanges shall conform to Tables 9 and 10.

Dimensions for type 17SV flange weld end preparations shall conform to Figure 7.

Dimensions for rough machining of ring grooves for corrosion resistant inlays shall conform to Table 8, or other weld preparations may be employed where the strength of the overlay alloy equals or exceeds the strength of the base materials.

Dimensions for type 17SV flange ring grooves shall conform to Table 5.

7.1.2.5.3 Flange face

Flange faces shall be fully machined. The nut bearing surface shall be parallel to the flange gasket face within 1°. The back face may be fully machined or spot faced at the bolt holes. The thickness of type 17SS and type 17SV flanges after facing shall meet the dimensions of Tables 7 to 10 as applicable. The thickness of type 6BX flanges shall meet the requirements of ISO 10423.

7.1.2.5.4 Gaskets

Type 6BX, 17SS and 17SV flanges in subsea completion equipment shall use type BX or SBX gaskets in accordance with 7.6. If these flanges are to be made up underwater in accordance with the manufacturer's written specification, they shall use internally cross-drilled type SBX ring gaskets to prevent fluid entrapment between the gasket and the ring groove during flange make-up.

Segmented flanges in subsea completion equipment shall use type RX or SRX gaskets in accordance with 7.6. If segmented flanges are to be made up underwater in accordance with the manufacturer's written specification, they shall use internally cross-drilled type SRX ring gaskets.

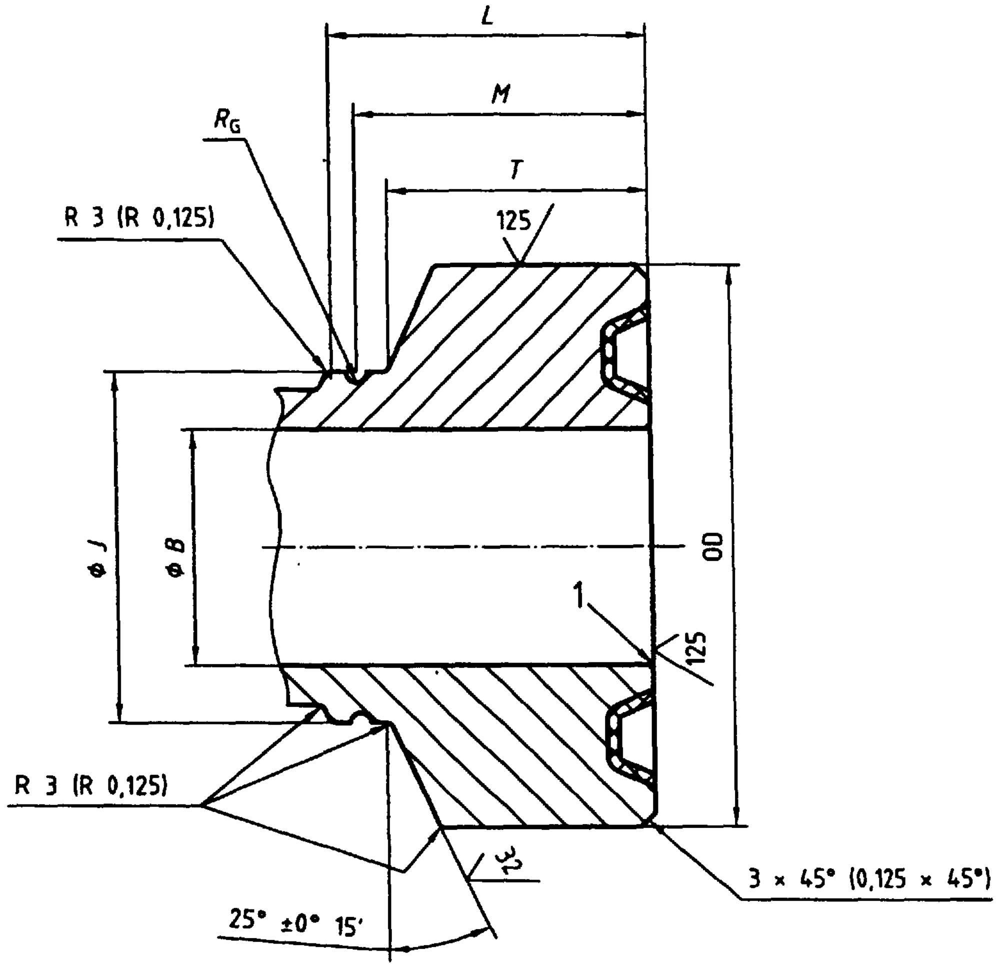
7.1.2.5.5 Corrosion-resistant ring grooves

All end and outlet flanges used on subsea completions shall be manufactured from, or inlayed with, corrosion-resistant alloy with proven sea water resistance under the specified operating conditions. The chosen material shall also be resistant to corrosion from the internal fluid. Corrosion-resistant inlayed BX and RX ring grooves shall comply with ISO 10423.

Prior to application of the inlay, preparation of the BX and RX ring grooves shall conform to the dimensions of Table 8 as applicable, or other weld preparations may be employed where the strength of the inlay alloy equals or exceeds the strength of the base material. The inlay material shall be compatible in accordance with the manufacturer's written specification with well fluid, inhibition fluid, injection fluids etc. and with both the base metal of the flange and the ring gasket material (welding, galling and dissimilar metals corrosion).

Table 9 — (A) Hub bore dimensions for type 17SV flanges for 34,5 MPa (5 000 psi) rated working pressure

Dimensions in millimetres
(inches in parentheses)



Key

1 Break sharp corner

NOTE All tolerances per API except as noted:

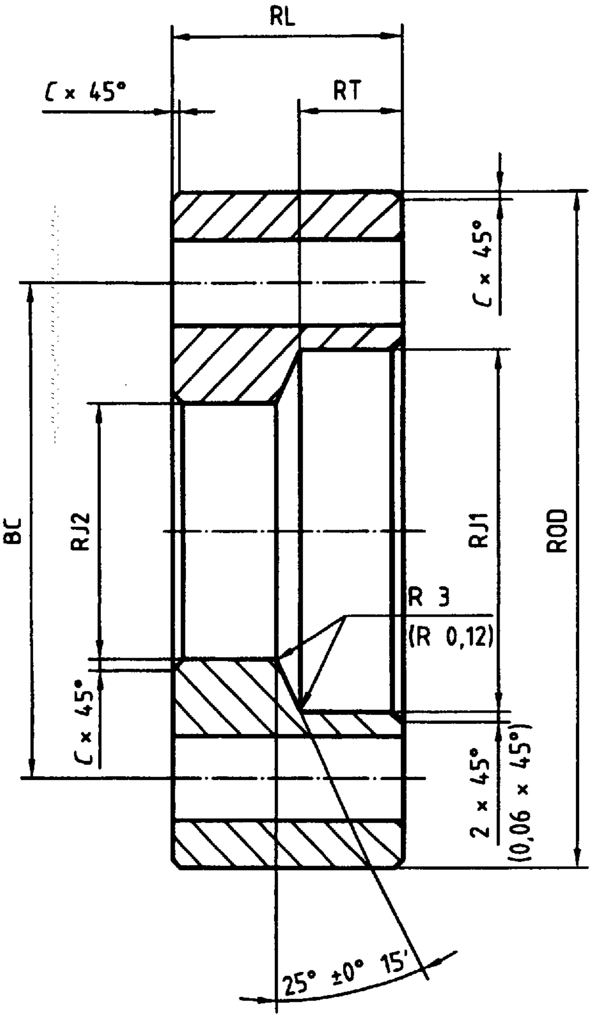
M $^{+0,7}_{0}$ mm $\left(^{0,03}_{0}\text{ in}\right)$

R_G $^{+0,1}_{0}$ mm $\left(^{0,05}_{0}\text{ in}\right)$

Hub bore dimensions															
Nominal size and bore B		Outside diameter OD		Total thickness T		Large diameter of neck J		Length of neck L		Groove location M		Retainer groove radius R_G		Ring gasket No. BX
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	
52	(2 1/16)	128	(5,081)	29,5	(1,166)	98	(3,656)	84	(3,282)	74	(2,907)	3,2	(0,125)	152
65	(2 9/16)	147	(5,78ss	29,5	(1,166)	112	(4,406)	84	(3,282)	74	(2,907)	3,2	(0,125)	153
78	(3 1/8)	160	(6,312)	29,5	(1,166)	126	(4,988)	88	(3,432)	78	(3,067)	3,2	(0,125)	154
103	(4 1/16)	194	(7,625)	30,5	(1,197)	159	(6,250)	96	(3,757)	96	(3,382)	3,2	(0,125)	155
130	(5 1/8)	240	(9,880)	36,0	(1,410)	197	(7,755)	121	(4,732)	111	(4,357)	3,2	(0,125)	169
179	(7 1/16)	272	(10,700)	41,5	(1,622)	281	(9,075)	141	(5,541)	127	(4,979)	4,8	(0,188)	156
228	(9)	340	(13,250)	41,5	(1,622)	296	(11,625)	156	(6,113)	141	(5,551)	4,8	(0,188)	157
279	(11)	415	(16,250)	42,0	(1,654)	372	(14,625)	162	(6,932)	162	(6,370)	4,8	(0,188)	158

Table 9 — (B) Basic dimensions of rings and bolts for type 17SV flanges for 34,5 MPa (5 000 psi) rated working pressure

Dimensions in millimetres
(inches in parentheses

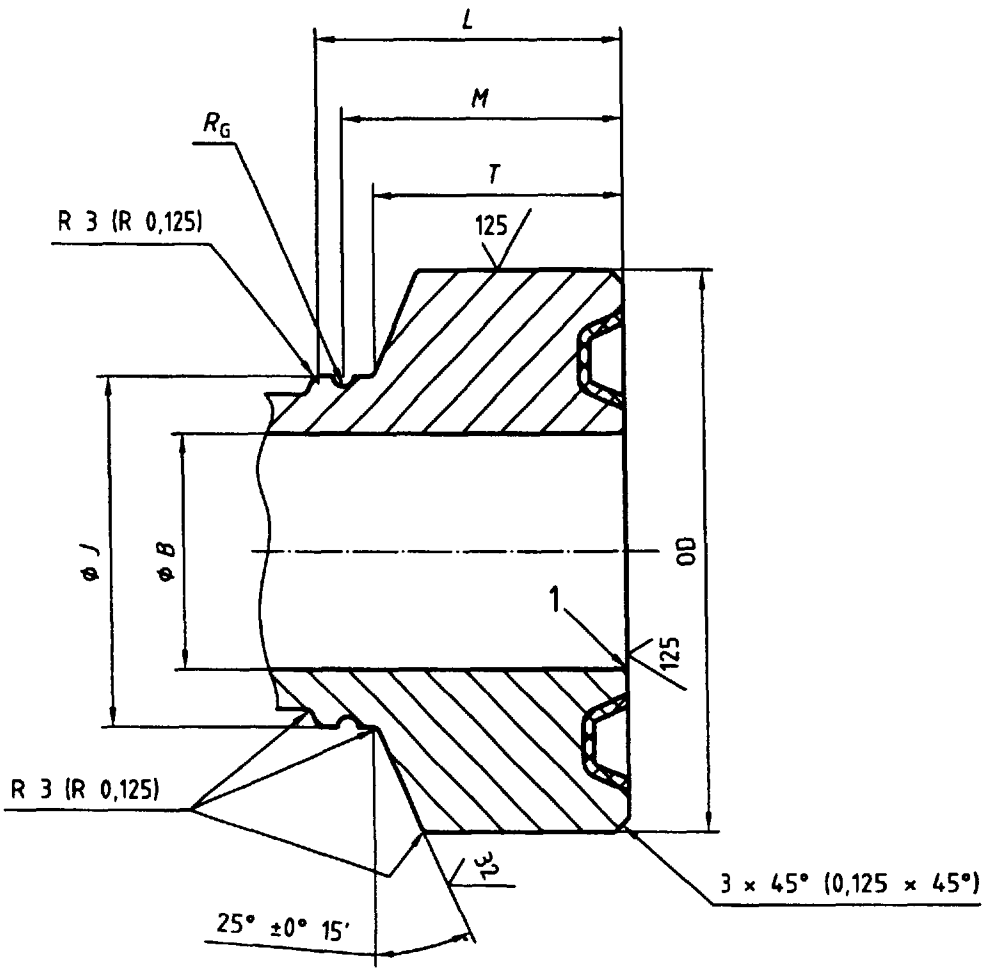


	Tolerances
ROD	
Size 52 to 130 (2 1/16 to 5 1/8)	±2 mm (±0,062)
Size 179 to 279 (7 1/6 to 11)	±3 mm (±0,125)
RL	$^{+3}_{0}$ mm $\left(^{+0,125}_{0}\right)$
RT	$^{+2}_{0}$ mm $\left(^{+0,062}_{0}\right)$
RJ1	$^{+1}_{0}$ mm $\left(^{+0,031}_{0}\right)$
RJ2	$^{+1}_{0}$ mm $\left(^{+0,031}_{0}\right)$
C	$^{+0,3}_{0}$ mm $\left(^{+0,010}_{0}\right)$
Bolt diameter	
Size 52 to 179 (2 1/6 to 7 1/16)	$^{+2,7}_{+0,5}$ mm $\left(^{+0,060}_{-0,020}\right)$
Size 228 to 279 (9 to 11)	$^{+2,7}_{+0,5}$ mm $\left(^{+0,090}_{-0,020}\right)$

																Bolts			
Nominal size and bore of hub		Outside diameter of ring ROD		Depth of LG ID RT		Large ID of ring RJ1		Small ID of ring RJ2		Length of ring RL		Chamfer C		Diameter of bolt circle BC		Number of bolts	Diameter of bolt holes	
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)		mm	(in)
52	(2 1/16)	216	(8,50)	24,5	(0,964)	129,4	(5,093)	94,5	(3,718)	63	(2,450)	3	(0,125)	165,1	(6,50)	8	26	(1,00)
65	(2 9/16)	245	(9,62)	24,5	(0,964)	148,5	(5,843)	113,5	(4,468)	63	(2,450)	3	(0,125)	190,5	(7,50)	8	29	(1,12)
78	(3 1/8)	267	(10,50)	24,5	(0,964)	162,0	(6,375)	127	(5,000)	66	(2,600)	3	(0,125)	208,2	(8,00)	8	32	(1,25)
103	(4 1/16)	312	(12,25)	25,3	(0,995)	195,8	(7,667)	160,4	(6,312)	49	(2,925)	3	(0,125)	241,3	(9,50)	8	26	(1,38)
130	(5 1/8)	375	(14,75)	30,7	(1,208)	289,9	(9,442)	198,6	(7,817)	99	(3,900)	3	(0,125)	292,1	(11,50)	8	42	(1,62)
179	(7 1/16)	394	(15,50)	36,1	(1,420)	273,4	(10,762)	282,1	(9,187)	114	(4,459)	5	(0,188)	317,5	(12,50)	12	39	(1,50)
228	(9)	488	(19,00)	36,1	(1,420)	333,2	(13,312)	296,9	(11,687)	128	(5,031)	5	(0,188)	398,7	(15,50)	12	45	(1,75)
279	(11)	595	(28,00)	36,9	(1,452)	414,4	(16,312)	878,1	(14,687)	149	(5,850)	5	(0,188)	482,6	(19,00)	12	51	(2,00)

Table 10 — (A) Hub dimensions for type 17SV flanges for 69,0 MPa (10 000 psi) rated working pressure

Dimensions in millimetres
(inches in parentheses)



Key

1 Break sharp corner

NOTE All tolerances per API except as noted:

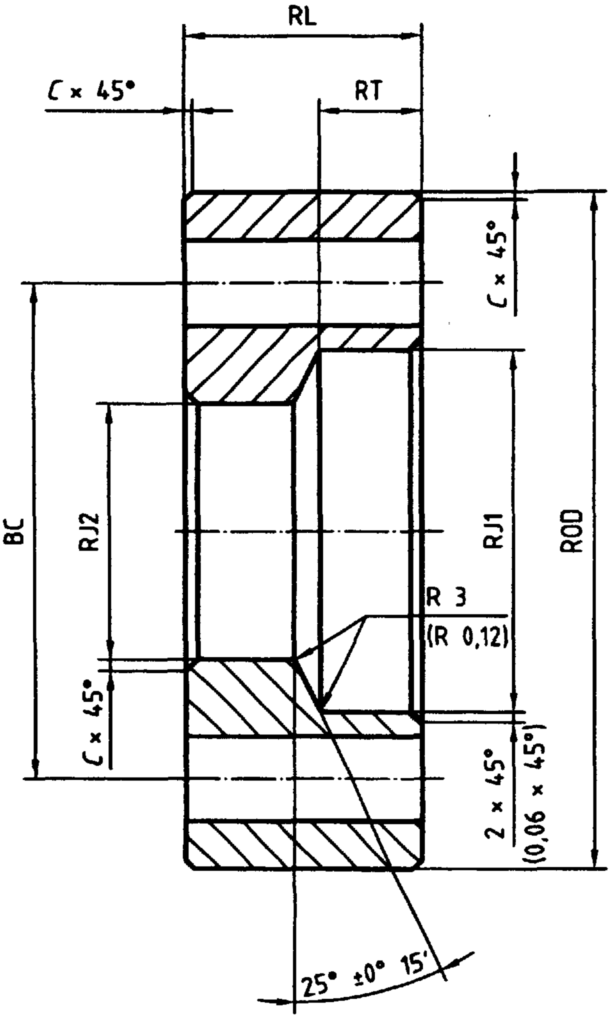
$M\ {}^{+0,7}_{0}\text{mm}\left({}^{0,03}_{0}\text{ in}\right)$

$R_G\ {}^{+0,1}_{0}\text{mm}\left({}^{0,005}_{0}\text{ in}\right)$

Hub dimensions														
Nominal size and bore		Outside diameter OD		Total thickness *T*		Large diameter of neck *J*		Length of neck *L*		Groove location *M*		Retainer groove radius R_G		Ring gasket No. BX
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	
46	(1 13/16)	115	(4,500)	29,5	(1,166)	82,6	(3,250)	84	(3,282)	74	(2,907)	3,2	(0,125)	151
52	(2 1/16)	130	(5,000)	29,5	(1,166)	95,3	(3,750)	84	(3,282)	74	(2,907)	3,2	(0,125)	152
65	(2 9/16)	150	(5,800)	29,5	(1,166)	115,6	(4,550)	84	(3,302)	75	(2,927)	3,2	(0,125)	153
78	(3 1/16)	175	(6,930)	30,5	(1,197)	144,3	(5,680)	94	(3,966)	84	(3,291)	3,2	(0,125)	154
103	(4 1/16)	215	(8,437)	33,3	(1,310)	178,0	(6,812)	109	(4,277)	99	(3,902)	3,2	(0,125)	155
130	(5 1/8)	255	(9,960)	38,1	(1,500)	211,7	(8,885)	121	(4,732)	111	(4,357)	3,2	(0,125)	169
179	(7 1/16)	350	(13,660)	42,0	(1,653)	305,7	(12,035)	158	(6,204)	143	(5,641)	4,8	(0,188)	156
228	(9)	415	(16250)	42,0	(1,653)	371,5	(14,625)	185	(7,270)	170	(6,707)	4,8	(0,188)	157
279	(11)	430	(18,870)	51,7	(2,035)	436,0	(17,245)	207	(8,153)	198	(7,591)	4,8	(0,188)	158
346	(13 5/8)	565	(22,250)	58,7	(2,309)	533,9	(20,625)	242	(9,531)	228	(8,969)	4,8	(0,188)	159

Table 10 — (B) Basic ring and bolt dimensions for type 17SV flanges for 69,0 MPa (10 000) rated working pressure

Dimensions in millimetres
(inches in parentheses



	Tolerances
ROD	
Size 52 to 130 (2 1/16 to 5 1/8)	±2 mm (±0,062)
Size 179 to 279 (7 1/6 to 11)	±3 mm (±0,125)
RL	$^{+3}_{0}$ mm $\left(^{+0,125}_{0}\right)$
RT	$^{+2}_{0}$ mm $\left(^{+0,062}_{0}\right)$
RJ1	$^{+1}_{0}$ mm $\left(^{+0,031}_{0}\right)$
RJ2	$^{+1}_{0}$ mm $\left(^{+0,031}_{0}\right)$
C	$^{+0,3}_{0}$ mm $\left(^{+0,010}_{0}\right)$
Bolt diameter	
Size 52 to 179 (2 1/6 to 7 1/16)	$^{+2}_{+0,5}$ mm $\left(^{+0,060}_{-0,020}\right)$
Size 228 to 279 (9 to 11)	$^{+2,5}_{+0,5}$ mm $\left(^{+0,090}_{-0,020}\right)$

Basic dimensions of ring												Bolts						
Nominal size and bore of hub		Outside diameter of ring ROD		Depth of LGID RT		Large ID of ring RJ1		Small ID of ring RJ2		Length of ring RL		Chamfer C		Diameter of bolt circle BC		Number of bolts	Diameter of bolt holes	
mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)	mm	(in)		mm	(in)
46	(1 13/16)	188	(7,38)	24,5	(0 ,964)	115,9	(4,562)	84,1	(3,312)	63	(2,450)	3	(0,125)	146,1	(5,75)	8	23	(0,88)
52	(2 1/16)	200	(7,88)	24,5	(0,.964)	128,6	(5,062)	96,8	(3,812)	63	(2,450)	3	(0,125)	158,8	(6,25)	8	23	(0,88)
65	(2 9/16)	232	(9,12)	24,5	(0 ,964)	148,9	(5,862)	117,1	(4,612)	63	(2,470)	3	(0,125)	184,1	(7,25)	8	26	(1.00)
78	(3 1/16)	270	(10,62)	25,3	(0 ,995)	177,6	(6,992)	145,8	(5,742)	72	(2,834)	3	(0,125)	215,9	(8,50)	8	29	(1,12)
103	(4 1/16)	316	(12,44)	28,1	(1,108)	215,9	(8,500)	174,6	(6,875)	88	(3,445)	3	(0,125)	258,8	(10,19)	8	32	(1,25)
130	(5 1/8)	357	(14,06)	33,0	(1,298)	254,6	(10,022)	218,8	(8,397)	99	(3,900)	3	(0,125)	300,0	(11,81)	12	32	(1,25)
179	(7 1/16)	480	(18,88)	36,9	(1,451)	348,5	(13,722)	307,8	(12,097)	130	(5,122)	5	(0,188)	403,4	(15,98)	12	42	(1,62)
228	(9)	552	(21,75)	36,9	(1,451)	409,7	(16,312)	378	(14I687)	158	(6,188)	5	(0,188)	496,3	(18,75)	16	42	(1,62)
279	(11)	654	(25,75)	46,6	(1,883)	480,9	(18,932)	489,6	(17,307)	180	(7,072)	5	(0,188)	505,2	(22,25)	16	48	(1,88)
346	(13 5/8)	768	(30,25)	53,5	(2,107)	586,7	(22,312)	525,4	(20,687)	215	(8,450)	5	(0,188)	673,1	(26,50)	20	51	(2,00)

7.1.2.5.6 Ring groove surface

All 23° angular surfaces on BX (SBX) ring grooves shall have a surface finish no rougher than 32 RMS. All 23° angular surfaces on RX (SRX) ring grooves shall have a surface finish no rougher than 63 RMS.

7.1.3 Testing

Loose flanges furnished under this subclause do not require a hydrostatic test prior to final acceptance.

7.2 ISO clamp hub-type connections

API clamp hub-type connections for use on subsea completion equipment shall comply with the dimensional requirements of ISO 13533. All end and outlet clamp hubs used on subsea completion equipment shall have their ring grooves either manufactured from, or inlayed with, corrosion resistant materials.

Corrosion-resistant inlayed ring grooves for clamp hubs shall comply with API Spec 16A.

7.3 Threaded connections

Loose threaded flanges and other threaded end and outlet connections shall not be used on subsea completion equipment handling produced fluid, except for tubing hangers. Threaded flanges may be used on non-production connections such as injection piping, provided there is an isolation valve and either a bolted flange or a clamp hub connection on the tree side of the threaded flange. Integral threaded connections, such as instrument connections, test ports, and injection/monitor connections, may be used in sizes up to 25,4 mm (1,00 in), if downstream of the first wing valve. If threaded connections are used upstream of the first wing valve, there shall be an isolation valve and either a bolted flange or a clamp hub connection on the tree side of the threaded connection. Threaded bleeder/grease/injection fittings shall be allowed upstream of the first wing valve without the isolation valve and flange/clamp hub if at least two pressure barriers between the produced fluid and the external environment are provided.

ISO type threaded connections used on subsea equipment covered by this part of ISO 13628 shall comply with the requirements of ISO 10423, as applicable.

7.4 Other end connectors

The use of other non-standard end connectors, such as misalignment connectors, non-ISO flanges, ball joints, articulated jumper assemblies or instrument/monitor flanges are allowable in subsea completion equipment if these connectors have been designed, documented and tested in accordance with the requirements established in clause 5.

Materials for OECs shall meet the requirements of 6.2 and 6.3. If the connector's primary seals are not metal-to-metal, redundant seals shall be provided. OECs used on subsea completion equipment shall have their ring grooves either manufactured from, or inlayed with, corrosion resistant materials.

7.5 Studs, nuts and bolting

Selection of stud, nut and bolting materials and platings should consider seawater induced chloride stress corrosion cracking and corrosion fatigue. Hydrogen embrittlement induced by cathodic protection systems should be considered. Consideration should be given to the effect of coatings on the cathodic protection systems.

Some high strength bolting materials may not be suitable for service in a seawater environment. Refer to 5.1.

7.5.1 ISO studs and nuts

The requirements for studs and nuts apply only to those used in end and outlet connections. Such studs and nuts used on subsea completion equipment covered by this part of ISO 13628 shall comply with ISO 10423.

7.5.2 Other studs, nuts and bolting

All other studs, nuts and bolting used on equipment shall comply with the manufacturer's written specifications.

7.5.3 Anti-corrosion coating/plating

The use of anti-corrosion coatings which may be harmful to the environment should be avoided. Local legislation should be checked for coatings deemed hazardous.

7.5.4 Make-up torque requirements

Make-up torque requirements shall comply with 5.1.3.4.

Studs, nuts and bolting for subsea service are often manufactured with anti-corrosion coatings which can dramatically reduce the stud-to-nut friction factor. Manufacturers shall document recommended make-up torque for their coated fasteners using charts, similar to the one in annex G.

The use of calibrated torque tools or bolt tensioning equipment is recommended to ensure accurate make-up torques.

7.6 Ring gaskets

7.6.1 General

This subclause covers type SBX and SRX ring gaskets for use in ISO type 6BX, 17SS, 17SV, and segmented flanged connections, and API Spec 16A clamp connections used in subsea completions equipment. Type SBX and SRX gaskets are vented to prevent pressure lock when connections are made up underwater.

Connections which will not be made up underwater may use non-vented gaskets type BX or RX gaskets.

Other proprietary gaskets shall conform to the manufacturer's written specification.

Although positioning of ring gaskets in their mating grooves is often a problem when making up flanges/clamp hubs on horizontal bores underwater, grease shall not be used to hold ring gaskets in position during make-up, since grease can interfere with proper make-up of the gasket. Likewise, the practice of tack welding rods to the OD of seal rings (to simplify positioning of the ring during make-up) shall not be used on gaskets for subsea service. Instead, gasket installation tools should be used if assistance is required to retain the gasket in position during make up.

7.6.2 Design

7.6.2.1 Dimensions

Type SBX and SRX ring gaskets shall conform to the dimensions and tolerances given in Tables 5 and 6 and shall be flat within 0,2 % of ring OD to a maximum of 0,4 mm (0,015 in).

7.6.2.2 Surface finish

All 23° angular surfaces on type SBX gaskets shall have a surface finish no rougher than 32 RMS. All 23° surfaces on type SRX gaskets shall have a surface finish no rougher than 63 RMS.

7.6.2.3 Pressure passage hole

Each BX and RX gaskets shall have one pressure passage hole drilled through its height as shown in ISO 10423:1994, Table 904.2 and Table 904.3.

Type BX and RX ring gaskets are not suitable for connections which will be made up underwater since fluid trapped in the ring groove may interfere with proper make up. Type SBX or SRX vented ring gaskets shall be used in place of type BX or RX gaskets on ISO type flange connections made up underwater in accordance with the manufacturer's written specification. Type SBX and SRX ring gaskets shall conform to Table 5 and Table 6, respectively.

If other types of end connectors are used on equipment which will be made up underwater in accordance with the manufacturer's written specification, then means shall be provided to vent trapped pressure between the gasket and the connector.

7.6.2.4 Reuse of gaskets

Except for testing purposes, ISO ring gaskets shall not be reused.

7.6.3 Materials

7.6.3.1 Ring gasket materials

Ring gaskets used for all pressure-containing flanged and clamped subsea connections shall be manufactured from corrosion-resistant materials. Gasket materials shall conform to the requirements of ISO 10423.

7.6.3.2 Coatings and platings

Coatings and platings used on ISO ring gaskets to aid seal engagement while minimising galling shall not exceed 0,01 mm (0,0005 in) thickness. The use of coatings which may be harmful to the environment should be avoided. Local legislation should be checked for coatings deemed hazardous.

7.6.3.3 Flange materials

Flange materials shall conform to the requirements in clause 5 as applicable and materials with a minimum yield strength of 517 MPa (75 000 psi) shall be used for type 17SV Flanges for 69,0 MPa (10 000 psi) rated working pressure.

7.7 Tree connectors and tubing hanger spools

7.7.1 General

This subclause covers the tree and tubing hanger spool connectors which attach the tree or tubing hanger spool to the subsea wellhead. In addition, this subclause covers tubing hanger spools.

7.7.1.1 Tree/tubing head spool connectors

Three types of tree/spool connectors are commonly used:

— hydraulic remote operated;

— mechanical remote actuated;

— mechanical diver/ROV operated.

All connectors shall be designated by size, pressure rating and the profile type of the subsea wellhead to which they will be attached (see Table 11). Tree/spool connectors shall conform to maximum standard pressure ratings of 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi), as applicable.

The pressure rating selected shall be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree, whichever is greater, unless relief is provided as described in 5.1.2.1.1. The tree connector may be a separate unit or may be integral with the XT valve block.

Table 11 — Wellhead systems — Standard sizes and types

Nominal system designation		Bop stack configuration	High pressure housing working pressure		Minimum vertical bore	
mm - MPa	(in - psi)		MPa	(psi)	mm	(in)
476 - 69	(18 3/4 - 10 000)	Single	69,0	(10 000)	446	(17,56)
476 -103	(18 3/4 - 15 000)	Single	103,5	(15 000)	446	(17,56)
425-35	(16 3/4 - 5 000)	Single	34,5	(5 000)	384	(15,12)
425-69	(16 3/4 - 10 000)	Single	69,0	(10 000)	384	(15,12)
527-540-14	(20 3/4- 21 1/4- 2 000)	Dual	13,8	(2 000)	472	(18,59)
346-69	(13 5/8 -10 000)		69,0	(10 000)	313	(12,31)
540-35	(21 1/4 - 5 000)	Dual	34,5	(5 000)	472	(18,59)
346-103	(13 5/8 -15 000)		103,5	(15 000)	313	(12,31)
476-69	(18 3/4 - 10 000)	Dual	69,0	(10 000)	446	(17,56)
346-103	(13 5/8-15 000)		103,5	(15 000)	313	(12,31)

7.7.1.2 Tubing hanger spools

7.7.1.2.1 Uses

Tubing hanger spools are commonly used to:

— provide a crossover between wellheads and subsea trees made by different equipment manufacturers;

— cut as crossover between different sizes and/or pressure ratings of subsea wellheads and trees;

— provide a surface for landing and sealing a tubing hanger if the wellhead is damaged or is not designed to receive the hanger;

— provide a means for attaching any guidance equipment to the subsea wellhead.

7.7.1.2.2 Types, sizes and pressure rating

The tubing hanger spool shall be designated by size, pressure rating, and the profile types of its top and bottom connections. Top connections are commonly either hub or mandrel type connections which shall match the tree connector. The bottom connection shall match the wellhead. The tubing hanger spool and connector may be manufactured as an integral unit. Tubing spools shall conform to standard pressure ratings of 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi), as applicable. When the tubing hanger spool and connector are manufactured as an integral unit, then the pressure rating shall apply to the unit as a whole. Pressure rating selected shall be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree whichever is greater, unless relief is provided as described in 5.1.2.1.1.

7.7.2 Design

7.7.2.1 Loads/conditions

As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree connector and tubing hanger spool:

— internal and external pressure;

— pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);

— mechanical preloads;

— riser bending and tension loads (completion and/or drilling riser);

— environmental loads;

— snagging loads ;

— fatigue considerations;

— vibration;

— mechanical installation (impact) loads;

— hydraulic coupler/flowline stab connector thrust and/or preloads;

— thermal expansion (trapped fluids, dissimilar metals);

— BOP loads;

— tree loads;

— flowline loads;

— installation/workover;

— overpull;

— corrosion.

The manufacturer shall document the load/capacity for the tree/spool connector using the load chart format illustrated in Figure 8. This format relates pressure to allowable bending moment for various tensions. The manufacturer shall state whether the basis of the graphs is stress limits or gasket separation limits.

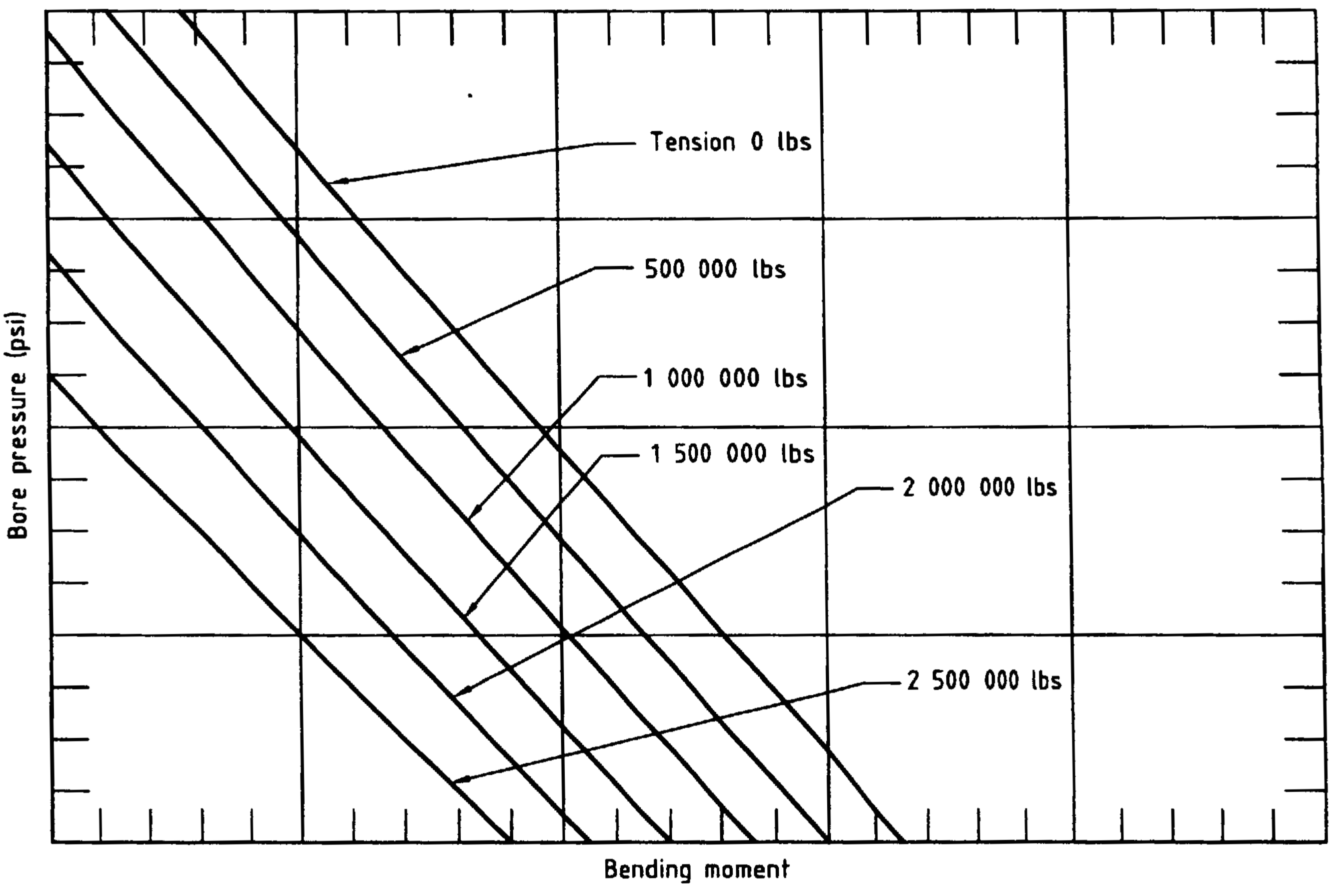


Figure 8 — Bore pressure vs bending moment with tension

7.7.2.2 Load/capacity

The tree/spool connector and/or tubing hanger spool shall provide preload and structural strength to provide sealing within the maximum rated loads as shown on the manufacturer's load/capacity chart (refer to Figure 8).

7.7.3 Design and functional requirements

7.7.3.1 Actuating pressures

Hydraulically actuated tree and tubing hanger spool connectors shall be capable of containing hydraulic release pressures of at least 25 % above normal operating release pressures in the event that normal operating release pressure is inadequate to effect release of the connector. The manufacturer shall document both normal and maximum operating release pressures.The connector design will provide greater unlocking force than locking force. The manufacturer will document the connector locking and unlocking pressures and forces.

7.7.3.2 Secondary release

Hydraulically actuated tree and tubing hanger spool connectors shall be designed with a secondary release method which may be hydraulic or mechanical. Hydraulic open and close control line piping shall be positioned to allow cutting by diver/ROV or contain a means to vent pressure if needed for the secondary release to function.

7.7.3.3 Position indication

Remotely operated tree connector and/or tubing hanger spool connectors shall be equipped with an external position indicator suitable for observation by diver/ROV.

7.7.3.4 Self-locking requirement

Hydraulic tree and tubing hanger spool connectors shall be designed to prevent release due to loss of hydraulic locking pressure. This may be achieved by the connector self-locking mechanism or backed up using a mechanical locking device or other demonstrated means. The design of mechanical locking devices must consider release in the event of malfunction.

7.7.3.5 Inlay of seal surfaces

Seal surfaces for tree and tubing hanger spool connectors which engage metal-to-metal seals shall be inlayed with corrosion resistant material which is compatible with well fluids, seawater, etc. Inlays are not required if the base metal is compatible with well fluids, seawater, etc.

7.7.3.6 Seals testing

Means shall be provided for testing all primary seals in the connector cavity to the rated working pressure of the tree/spool connector or tubing hanger, whichever is lower.

7.7.3.7 Seal replacement

The design shall allow for easy and safe replacement of the primary seal and stab subs.

7.7.3.8 Hydraulic lock

The design shall ensure that trapped fluid does not interfere with the installation of the connector.

7.7.4 Testing

7.7.4.1 General

The following test procedure applies to both mechanical and hydraulic connectors.

7.7.4.2 Factory acceptance testing

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.2.

After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and if appropriate, secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

7.8 Tree stab subs and seal subs

7.8.1 General

7.8.1.1 This subclause covers the stab subs which provide pressure-containing conduits between the valve block and tubing hanger. It also covers the seal subs when used, which provide pressure-containing conduits between the valve block and re-entry hub. Stab subs are used on the production (injection) bore, annulus bore, SCSSV control lines and downhole chemical injection lines. The housing for electrical penetrator can also be treated as a stab sub. Seal subs are used on the production (injection) bore, annulus bore and SCSSV lines when they are routed through the re-entry spool. This subclause provides information with respect to design performance standards, materials, testing, marking, storing and shipping.

7.8.1.2 Stab subs and seal subs in the production and annulus bore shall conform to standard maximum pressure ratings of 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) as covered by this part of ISO 13628. Where production or annulus stabs or seal subs may be exposed to SCSSV control pressure due to a leak in the system, then the pressure rating selected shall be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree whichever is greater, unless alternative arrangements such as venting down SCSSV pressure are incorporated to prevent over-pressuring of the connector. The affects of leaking SCSSV control pressure, acting externally on stabs and seal subs must also be considered in their design. Stab subs or seal subs used to conduct SCSSV control fluid or injected chemicals shall be rated to a working pressure equal to or greater than the SCSSV control pressure or injection pressure, respectively, whichever is the higher.

7.8.2 Design

7.8.2.1 Loads/conditions

As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the stab subs/seal subs:

— internal and external pressure;

— separation loads;

— bending loads during installation;

— thermal expansion;

— corrosion;

— galling.

7.8.2.2 Seal design

The seal mechanism may be either metal-to-metal, in which case it shall have a resilient seal back-up or may be redundant resilient seals, or as specified by the purchaser. The design should consider ease and safety of seal replacement.

7.8.2.3 Exclusion of debris

The design should consider the affect or the exclusion of debris at the stab sub-interface.

7.9 Valves, valve blocks and actuators

7.9.1 General

This subclause covers subsea valves, valve blocks and actuators used on subsea trees. It provides information with respect to design performance standards, materials, testing, marking, storing and shipping.

7.9.1.1 Flanged end valves

Valves and valve blocks having ISO type flanged end connections shall use integral, welding neck, or blind ring-joint flanges as specified in 7.1.

For units having end and outlet connections with different pressure ratings, the rating of lowest rated pressure-containing part shall be the rating of the unit.

7.9.1.2 Other end connector valves

ISO threaded end valves shall only be supplied in accordance with 302.1 of ISO 10423:1994 and 7.3 of this part of ISO 13628. Clamp-type connections shall conform to API 16A. OECs shall conform to 7.4 of this part of ISO 13628.

7.9.2 Design

7.9.2.1 Valves and valve blocks

7.9.2.1.1 General

Valves and valve blocks used in the subsea tree bores and tree piping shall conform to the applicable end to end and bore dimensional requirements of ISO 10423:1994, clause 905. Other valve and valve block dimensions shall be in accordance with 7.1 through 7.6.

If the lower end connection of the tree which mates to the tree connector encapsulates SCSSV control lines, then the rated working pressure of this end connection shall be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree whichever is greater, unless relief is provided as described in 5.1.2.1.1.

For valves and valve blocks used in TFL applications, the design shall also comply with API RP 17C for TFL pumpdown systems.

Consideration should be given to the inclusion of diver/ROV valve overrides, particularly in the vertical run to facilitate well intervention in the event of hydraulic control failure.

Re-packing/greasing facilities if incorporated shall include a non return valve.

7.9.2.1.2 Valves

a) Valves shall be rated for standard or sandy service, as determined by ISO 10433. Additionally, service classification shall be generally as identified in clause 5, with respect to temperature and material class.

b) Valves for subsea service shall be designed considering the effects of external hydrostatic pressure and the environment as well as internal fluid conditions.

c) Manufacturers of subsea valves shall document design and operating parameters of the valves as listed in Table 12.

d) Measures shall be taken to ensure that there are no burrs or upsets at the gate and seat bores that may damage the gate and seat surfaces or interfere with the passage of wireline or TFL tools.

Table 12 — Design and operating parameters of valves and actuators

A	Valve
1	Nominal bore size
2	Working pressure
3	Class of service
4	Temperature classifications
5	Type and size connections
6	Valve stroke
7	Overall external dimensions and mass
8	Materials class rating
9	Failed position (open, closed, in place) [a]
10	Unidirectional or bi-directional
B	**Actuator**
1	Minimum hydraulic operating pressure
2	Maximum hydraulic operating pressure
3	Temperature classifications
4	Actuator volume displacement .
5	Override force or torque required [b]
6	Maximum override force or torque [b]
7	Overall external dimensions and mass
8	Make and model number of valves the actuator is designed for:
C	**Valve/hydraulic actuator assembly**
	At maximum rated depth of assembly and maximum rated bore pressure hydraulic pressure in MPa (psi) the valve will:
1	Start to open from previously closed position
2	Fully open
3	Start to close from previously open position
4	Fully closed
	At maximum rated depth of assembly and 0 bore pressure, hydraulic pressure in MPa (psi) the valve will:
5	Start to open from previously closed position
6	Fully open
7	Start to close from previously open position
8	Fully closed
9	Nominal depth rating per 7.9.2.3.3

[a] Where applicable.

[b] If equipped with manual or ROV override.

7.9.2.1.3 Valve blocks

Valve blocks shall meet the design requirements given in 6.1 and in ISO 10423.

7.9.2.2 Actuators

This part of ISO 13628 addresses mechanical and hydraulic actuators. Electrical actuators are acceptable on subsea trees, however their detailed design guide lines are outside the scope of this part of ISO 13628. They shall however meet the general design criteria, material and testing requirements of hydraulic actuators.

7.9.2.2.1 General

The design of subsea valve actuators shall comply with the following:

a) Design shall consider marine growth, fouling, corrosion, hydraulic operating fluid and, if exposed, the well stream fluid.

b) Subsea actuator opening and closing force shall be sufficient to operate the subsea valve when the valve is at the most severe design operating conditions without exceeding 90 % of the nominal hydraulic operating pressure as defined in (c) below.

c) Subsea actuators covered by this part of ISO 13628 shall be designed by the manufacturer for nominal hydraulic working pressure rating of either 10,3 MPa (1 500 psi) or 20,7 MPa (3 000 psi) or in accordance with the manufacturer's specification.

7.9.2.2.2 Manual actuators

a) The design of the manual actuation mechanism shall take into consideration the ability of divers, ADSs and/or ROVs, for operations. Manual valves shall be operable by divers and/or ROVs. The valve shall be protected from over torquing.

b) Manufacturers of manual actuators or overrides for subsea valves shall document maintenance requirements, number of turns to open, nominal operating torque, maximum allowable torque, and where appropriate linear force to actuate.

c) Valves shall be turned in the counter-clockwise direction to open and the clockwise direction to close as viewed from the end of the stem.

d) Intervention fixtures for manual valve actuators shall comply with the requirements of a recognized industry standard for ROV[4] and ISO 13628-9.

7.9.2.2.3 Hydraulic actuators

a) Hydraulic actuators shall be designed for a specific valve or specific group of valves.

b) Hydraulic actuators shall have porting to facilitate flushing of the hydraulic cylinder.

c) Hydraulic actuators shall be designed to operate without damage to the valve or actuator (to the extent that any other performance requirement is not met), when hydraulic actuation pressure (within its design pressure rating) is either applied or vented under any valve bore pressure conditions, or stoppage of the valve bore sealing mechanism at any intermediate position.

d) The design of the actuator shall consider the effects of external hydrostatic pressure at the manufacturer's maximum rated water depth and the MRWP of the valve.

e) Manual overrides, if provided, shall be in accordance with the following requirements:

— rotation type override shall open the valve with a counter-clockwise rotation as viewed from the end of the stem on fail closed valves;

— push-pull type override for fail closed valve shall open the valve with a push on the override.

f) For fail-open valves, the manufacturers shall document the method of override.

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[4] For the purposes of this part of ISO 13628, the industry standard will be replaced by ISO 13628-8 when the latter becomes publicly available.

g) Position indicators should be incorporated on all actuators. They shall clearly show valve position (open/close and full travel) for observation by diver/ROV. Where the actuator incorporates ROV override, consideration should be given to visibility of the position indicator from the working ROV.

h) The actuator springs (coils) for fail closed (open) operation of the valve shall be designed to provide a minimum mean spring life of 5 000 cycles.

i) Actuator manufacturer shall document design and operating parameters, as listed in Table 12.

7.9.2.3 Valve/hydraulic actuator assembly

7.9.2.3.1 Closing/opening force

The subsea valve and hydraulic actuator assembly design shall utilize valve bore pressure and/or spring force to assist opening and/or closing of the valve.

7.9.2.3.2 Actuator protection from wellbore pressure

Means shall be provided to prevent overpressuring of the actuator, in the event that well bore pressure leaks into the actuator.

7.9.2.3.3 Water depth

Manufacturer shall specify the maximum water depth rating of the valve/actuator assembly. Subsea valve and actuator assemblies designated as fail-closed (open) shall be designed and fabricated to be capable of fully closing (opening) the valve at the maximum rated water depth under all of the following conditions:

a) from 0,10 MPa (14,7 psi) to maximum working pressure of the valve in the valve bore;

b) differential pressure equal to the rated bore pressure across the valve bore sealing mechanism at the time of operation;

c) external pressure on the valve/actuator assembly at the maximum rated water depth using seawater specific gravity of 1,03;

d) no hydraulic assistance in the closing (opening) direction of the actuator other than hydrostatic pressure at the operating depth;

e) 0,80 MPa (114,7 psi) plus seawater ambient hydrostatic pressure at the maximum rated depth of the assembly acting on the actuator piston in the opening (closing) direction;

f) other actuator performance criteria may be specified by the manufacturer, such as wire/coiled tubing shearing design criteria, but these are to be considered separately from the above fundamental set of criteria.

NOTE The rated water depth is calculated using the above set of "extreme worst case" conditions for the purpose of standard reference, but does not necessarily represent operating limitation. Additional information relating to operating water depth for specific applications may be provided and agreed between manufacturer and user as being more representative of likely field conditions.

7.9.3 Materials

In addition to end and outlet connections, valve bonnet gasket sealing surfaces shall be manufactured from or inlayed with corrosion resistant material.

7.9.4 Testing

7.9.4.1 Performance verification testing

Performance verification testing is required to qualify specific valve and valve actuator designs manufactured under this part of ISO 13628. (Refer to 5.1.7).

7.9.4.1.1 Sandy service

Sandy service subsea valves and actuator shall be tested in accordance with ISO 10433, in addition to tests as specified in 5.1.7.

7.9.4.1.2 Valve and actuator assembly testing

Subsea valve and actuator assemblies shall be tested to demonstrate the performance limits of the assembly. Unidirectional valves shall be tested with pressure applied in the intended direction. Bi-directional valves shall be tested with pressure applied in both directions in separate tests.

For a fail-closed (open) valve, with the assembly subjected to external hydrostatic pressure (actual or simulated) of the maximum rated water depth and full rated bore pressure, applied as a differential across the gate, the valve shall be shown to be opened (closed) fully from a previously closed (open) position with a maximum of 90 % of the nominal operating hydraulic fluid pressure above actual or simulated ambient pressure, applied to the actuator.

For a fail-closed (open) valve, with the assembly subjected to the external hydrostatic pressure, (actual or simulated) of the maximum rated water depth and atmospheric pressure in the body cavity, the valve shall be shown to move from a previously fully open (closed) position to a fully closed (open) position as the hydraulic pressure in the actuator is lowered to a minimum of 0,69 MPa (100 psi) above ambient pressure.

For a fail-in-place valve, with the assembly subjected to the external hydrostatic pressure (actual or simulated) of the maximum rated water depth, the valve shall be shown to be closed or opened fully from a previously open or closed position with no more than 90 % of the normal operating hydraulic fluid pressure applied to actuator with the full rated bore pressure. The fail-in-place valve shall remain in position when hydraulic operating fluid is vented to a minimum of 0,69 MPa (100 psi) above ambient pressure.

7.9.4.2 Factory acceptance testing

Each subsea valve and valve actuator shall be subjected to a hydrostatic and operational test to demonstrate the structural integrity and proper assembly and operation of each completed valve and/or actuator.

7.9.4.2.1 Subsea valve

Each subsea valve shall be factory acceptance tested in accordance with ISO 10423, 605.9.

7.9.4.2.2 Subsea valve actuator

a) **Hydrostatic shell test**

Each actuator cylinder and piston shall be subjected to a hydrostatic test to demonstrate structural integrity. The test pressure shall be a minimum of 1,5 times the nominal hydraulic working pressure rating of the actuator. No leakage shall be allowed. After successful completion of the hydrostatic test, each actuator cylinder and piston shall be marked with the test pressure, in accordance with 7.9.5, to provide future identification of tested pieces. If hydrostatic testing of the cylinder and piston is performed after final actuator assembly, stamping of the piston shall not be required.

b) **Actuator seal test**

The actuator seals shall be pressure tested in two steps by applying pressures of 15 % to 25 % and a minimum of 100 % of the nominal hydraulic rated working pressure of the actuator. No seal leakage shall be allowed. The test media shall be specified by the manufacturer. The minimum test duration for each test pressure shall be 3 min. The test period shall not begin until the test pressure has been reached and has stabilized. The test gauge pressure reading and time at the beginning and at the end of each pressure holding period shall be recorded. The low pressure test is not applicable for flow-by type actuators.

c) **Actuator operational test**

The actuator shall be tested for proper operation by stroking the actuator from the fully closed position to the fully open position, a minimum of three times. The actuator shall operate smoothly in both directions in accordance with the manufacturer's written specification. Test media for hydraulic actuators shall be specified by the manufacturer.

7.9.4.2.3 Testing of valve/actuator assembly

After final assembly, each valve/actuator assembly (including override if fitted) shall be subjected to a functional test to demonstrate proper assembly and operation in accordance with the manufacturer's written specification. The functional test shall be performed by the subsea valve/actuator assembler. All test data shall be recorded on a data sheet and shall be maintained by the subsea valve/actuator assembler for at least 5 years. The test data sheet shall be signed and dated by the person(s) performing the functional test(s).

The subsea valve and actuator assembly shall meet the testing requirement of 7.9.4.2.1 and this paragraph except that the hydrostatic shell test need not be repeated if they have been performed on the valve and actuator separately.

Valves used in TFL service shall be drift tested in accordance with API RP 17C for TFL pumpdown systems.

7.9.5 Marking

7.9.5.1 Subsea valve marking

The valve portion of subsea valve equipment shall be marked as shown in Table 13. The manufacturer may arrange required nameplate markings as suitable to fit available nameplate space.

Table 13 — Marking for subsea valves

Marking		Application
1	Manufacturer's name or trademark	Body (if accessible) and nameplate
2	ISO 13628-4	Nameplate
3	MRWP	Body (if accessible), bonnet and nameplate
4	End flange material, where applicable. The letters ISO 13628-4 and ISO material designation	Flange periphery or nameplate at manufacturer's option
5	Class of service (standard or sandy)	Nameplate
6	Material class rating	Nameplate
7	Nominal subsea valve size and, when applicable, the restricted or oversized bore	Body or nameplate or both at manufacturer's option
8	Flange and ring-joint designation and size	Subsea valve flange periphery
9	Direction of flow if applicable	Body or nearest accessible location
10	Serial or identification number unique to the particular subsea valve	Nameplate and body if accessible
11	Temperature rating	Nameplate
12	Traceability number if applicable	Bonnet, body
13	PSL level	Body and nameplate

7.9.5.2 Subsea valve actuator marking

The subsea valve actuator shall be marked as shown in Table 14.

Table 14 — Marking for subsea valve actuator

Marking		Application
1	Manufacturer's name or trademark	Nameplate and cylinder
2	ISO 13628-4	Nameplate
3	Maximum working pressure of the cylinder	Nameplate
4	Manufacturer's model number	Nameplate
5	Serial or identification number	Nameplate and cylinder
6	Temperature rating	Nameplate
7	Hydrostatic test pressure	Cylinder
8	PSL level	Nameplate

7.9.5.3 Subsea valve and actuator assembly marking

The subsea valve and actuator assembly shall be marked as shown in Table 15.

Table 15 — Marking for subsea valve and actuator assembly

Marking		Application
1	Assembler's name or trademark	Nameplate
2	ISO 13628-4	Nameplate
3	Assembly serial or identification number	Nameplate
4	Rated water depth	Nameplate

7.9.5.4 Nameplates

Nameplates shall be attached after final coating the equipment. Nameplates should be designed to remain legible for the design life of the valve/actuator.

7.9.5.5 Low stress marking

All marking done directly on pressure-containing components, excluding peripheral marking on API flanges, shall be done using low stress marking methods.

7.9.5.6 Flow direction

All subsea valves which are designed to have unidirectional flow should have the flow direction prominently and permanently marked.

7.10 TFL wye spool and diverter

7.10.1 General

The TFL wye spool is located between the master valves and the swab closure. The purpose of the wye spool is to provide a smooth transitional passage way for TFL tools from the flowline(s), to the vertical production bore(s) of the well, while still permitting normal wireline, or other types of vertical access through the tree top. Refer to API RP 17C for TFL pumpdown systems for further information.

7.10.2 Design

7.10.2.1 WYE spool

All transitional surfaces through the wye spool shall have chamfered surfaces without reduced diameter or large gaps in accordance with the dimensional requirements of API RP 17C for TFL pumpdown systems.

The intersection of the flowloop bore to the vertical wellbore shall comply with the dimensional requirements of API RP 17C for TFL pumpdown systems.

7.10.2.2 Diverter

Provisions shall be made to divert TFL tools to and from the TFL loops in accordance with the manufacturer's written specification. Diverter device(s) shall be designed in accordance with API RP 17C for TFL pumpdown systems.

7.10.2.3 Interfaces

7.10.2.3.1 The wye spool may be integral with either the master valve block or swab valve block. When non-integral, the following shall apply.

7.10.2.3.1.1 Master valve interface

The wye spool lower connection shall be sized to mate with the master valve upper connection. This connection shall provide pressure integrity equal to the working pressure of the subsea tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacturer.

7.10.2.3.1.2 Swab closure interface

The upper wye spool connection shall be sized to mate with the swab closure lower connection. The connection shall provide pressure integrity equal to the working pressure of the subsea tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacturer.

7.10.2.3.1.3 TFL flowloop interfaces

The wye outlet connection shall be sized to mate with either the TFL flowloop piping or the wing valve. This connection shall provide pressure integrity equal to the working pressure of the tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacturer. Combined pressure loading, piping preloads (or tension), flowloop make-up and any other applied loads shall not exceed the allowable yield stress of the TFL piping as defined in 7.16, nor shall it reduce the flowline internal diameter to below the drift diameter. The bore of the wye spool shall be aligned with the bore of the flowloop according to the dimensional requirements of API RP 17C for TFL pumpdown systems. Angles of the TFL wye spool/flowloop connection shall be less than or equal to 15° from vertical.

7.10.2.3.1.4 WYE spool/diverter interface

The diverter bore shall be concentric with the bore of the flowline and a smooth transition surface should be used to connect the bores. In addition to the straight section of the flowloop above the transition surface, a straight section shall also be provided above or below any locking recess or side pocket. The internal surface shall provide a smooth transition from cylindrical passage to curvature of the loop.

7.10.3 Testing

All TFL wye spools and diverters shall be tested in accordance with 5.4 and drift tested as specified in API RP 17C for TFL pumpdown systems.

7.11 Re-entry spool

7.11.1 General

7.11.1.1 This subclause addresses the upper terminations of the tree wellbores. The design and manufacture of control couplers/connectors which may or may not be integral with the tree upper connection, are addressed in 7.20.2.5.

7.11.1.1.1 Purpose

The purpose is to provide an uppermost attachment interface on the tree for connection of:

— a tree running tool used for installation and workover purposes;

— a tree cap;

— internal crown plugs, if applicable.

7.11.1.2 Integral or non-integral

The tree upper connection may consist of a separate spool which mechanically connects and seals to the tree upper valve or upper valve block termination. The upper connection may consist of an integral interface profile in or on top of the valve(s) body.

7.11.2 Design

7.11.2.1 Pressure rating

The re-entry spool shall be rated to the tree working pressure plus an allowance for other loading effects as defined in 7.11.3.

7.11.2.2 Re-entry spool upper connection/profile

The tree re-entry spool shall provide a locking and sealing profile for the tree running tool and/or tree cap. The design strength of the connection shall be based on loading considerations specified in 7.11.3. Independent sealing surfaces shall be provided for each treebore. Corrosion resistant materials or inlays shall be provided for these seal surfaces. Inlays are not required if the base metal is corrosion resistant. The connection shall also provide for passage of wireline tools and shall not limit the drift diameter of the treebore.

7.11.2.3 Secondary guidance

A secondary guidance system shall be provided to ensure that when the tree running tool/tree cap is installed, fine alignment/orientation of the seal stabs and hydraulic couplings is achieved prior to seal engagement.

7.11.2.4 Crown plug profiles

The effect of wall thickness reductions due to crown plug profiles machined into the tree re-entry spool shall be included in design analysis and documentation as required in 5.1.

7.11.3 Design loads/conditions

Analytical design methods shall conform to 5.1. As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the re-entry spool:

— internal and external pressure;

— pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);

— mechanical preloads;

— riser bending and tension loads;

— external environmental loads;

— fatigue considerations;

— vibration;

— mechanical installation (impact) loads;

— hydraulic coupler thrust and/or preloads;

— corrosion.

7.12 Subsea tree cap

7.12.1 General

7.12.1.1 Conventional trees normally use externally attached tree caps, either non-pressure-containing or pressure-containing. Horizontal trees may use either internally or externally attached tree caps. When internal caps are used an external debris cap or cover may be installed to protect sealing surfaces and hydraulic couplers. Hydraulic couplers may be incorporated in the tree cap. These may be integral with the cap or externally attached. The design and manufacture of control couplers/connectors are addressed in 7.20.2.5.

7.12.1.1.1 Non-pressure-containing tree cap

Non-pressure-containing tree caps protect the tree re-entry spool, hydraulic couplers and vertical wellbores from possible environmental damage or undesired effects resulting from corrosion, marine growth or potential mechanical loads. Design of non-pressure-containing tree caps shall comply with clause 5 and is not addressed further in this part of ISO 13628.

7.12.1.1.2 Pressure-containing tree cap

An externally attached pressure-containing tree cap provides protection to the re-entry spool and hydraulic couplers and provides an additional sealing barrier between tree wellbore(s) and the environment. The cap may also perform the function of mating the control system hydraulic couplers.

7.12.2 Design

7.12.2.1 General

This subclause applies to pressure-containing tree caps. The design of this equipment shall comply with 5.1. The requirements given below are generally applicable to both internally and externally attached tree caps.

7.12.2.2 Pressure rating

The tree cap shall be rated to the tree working pressure plus an allowance for other loading effects as defined in 7.12.2.4.

7.12.2.3 Tree cap locking mechanism

The tree cap locking mechanism shall be designed to contain the rated tree working pressure acting over the corresponding seal areas that interface with the upper tree connection. Three types of tree cap are commonly used:

— hydraulic remote operated;

— mechanical remote operated;

— mechanical diver/ROV operated.

7.12.2.4 Design loads/conditions

Analytical design methods shall conform to 5.1. As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree cap:

— internal and external pressure;

— pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed) unless relief is provided as described in 5.1.2.1.1;

— mechanical preloads;

— installation string bending and tension loads;

— external environmental loads;

— fatigue considerations;

— vibration;

— mechanical installation (impact) loads;

— hydraulic coupler thrust and/or preloads;

— corrosion;

— dropped object and snag loads.

7.12.3 Design and functional requirements

7.12.3.1 Installation pressure test

A means shall be provided to test the upper tree connection and tree cap seal(s) after installation.

7.12.3.2 Pressure venting

A means shall be provided such that any pressure underneath the cap may be vented prior to cap release. This function may be designed to be automatic through the tree running tool or be performed independently by diver/ROV.

7.12.3.3 Hydraulic lock

A means shall be provided for the prevention of hydraulic lock during installation of the tree cap.

7.12.3.4 Guidance and orientation

Means shall be provided to guide and orient the tree cap relative to the re-entry spool interface. Where guidance and orientation is dependent on extended PGB guide posts, alternative means of orienting the cap during surface installation/testing shall be considered to prevent damage to the re-entry hub seal bores during installation of the cap on the tree.

7.12.3.5 Operating pressure

Hydraulically actuated tree caps shall be capable of containing hydraulic release pressures of at least 25 % above normal operating release pressures in the event that normal operating release pressure is inadequate to effect release of the connector. The manufacturer shall document both normal and maximum operating release pressures. The unlocking force shall be greater than the locking force, the value shall be documented by the manufacturer.

7.12.3.6 Secondary release

Hydraulically actuated tree caps shall be designed with a secondary release method which may be hydraulic or mechanical. Diver/ROV/remote tooling methods should be considered. Hydraulic open and close control line piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if needed for the secondary release to function.

7.12.3.7 External position indication

Tree caps shall be equipped with an external position indicator to show when the tree cap is fully locked.

7.12.3.8 Self-locking requirement

Hydraulic tree caps shall be designed to prevent release due to loss of hydraulic locking pressure.

This may be achieved or backed up using a mechanical locking device or other demonstrated means. The design of the locking device shall consider release in the event of a malfunction.

7.12.4 Materials

Materials shall conform to 5.2. Seal surfaces for tree caps which engage metal-to-metal seals shall be inlayed with a corrosion-resistant material which is compatible with well fluids, seawater, etc. Inlays are not required if the base material is compatible with well fluids, seawater, etc.

7.12.5 Testing

7.12.5.1 General

The following test procedure applies to tree cap connectors having either both mechanical or hydraulic connectors.

7.12.5.2 Factory acceptance testing

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.3.

After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test in accordance with the requirements given in 7.9.4.2.3.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms, as appropriate. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

7.13 Tree cap running tool

7.13.1 General

Tree cap running tool is used to install and remove subsea tree cap assemblies. Tree cap running tools may be mechanically or hydraulically operated.

Tools for running tree caps may have some of the following functions:

— actuation of the tree cap connector;

— pressure tests of the tree cap seals;

— relieve pressure beneath the tree cap;

— injection of corrosion inhibitor fluid.

7.13.2 Design

7.13.2.1 Operating criteria

The manufacturer shall specify the operating criteria for which the tree cap running/retrieval tool is designed.

NOTE Tree cap running/retrieval tools should be designed to be operable in the conditions/circumstances expected to exist during tree cap running/retrieving operations and well re-entry/workover operations. Specific operating criteria (design loads and angle limits, etc.) should consider the maximum surface vessel motions and resulting maximum running string tensions and angles which may occur.

7.13.2.2 Loads

As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree cap running tool:

- internal and external pressure;
- pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);
- mechanical preloads;
- installation string bending and tension loads;
- environmental loads;
- fatigue considerations;
- vibration;
- mechanical installation (impact) loads;
- hydraulic coupler thrust and/or preloads;
- thermal expansion (trapped fluids, dissimilar metals);
- installation/workover overpull;
- corrosion.

The manufacturer shall specify the loads/conditions for which the equipment is designed. The manufacturer shall document the load/capacity for their tree cap running tool connector using the load chart format illustrated in Figure 8, which relates pressure to allowable bending moment for various tensions. The manufacturer shall state whether the basis of the graphs are stress limits or seal separation limits.

7.13.2.3 Tree cap to running tool interfaces

7.13.2.3.1 General

The interface between the tree cap and running tool shall be designed for release at a running string departure angle as documented by the manufacturer to meet the operational requirements. This release shall not cause any damage to the tree cap such that any other performance requirement is not met.

The tree cap interface consists of several main component areas:

- locking profile and connector;
- re-entry seal (where applicable);
- extension subs or seals (where applicable);
- controls and instrumentation (where applicable).

7.13.2.3.2 Locking profile and connector

The tree cap running tool shall land and lock onto the locking profile of the tree cap and shall withstand separating forces resulting from applied mechanical loads and when applicable the rated working pressure of the tree as specified by the manufacturer. The tree cap running tool connector shall meet functional requirements set forth in 7.13.2.2.

Means shall be provided to prevent trapped fluid from interfering with make-up of the hydraulic or mechanical running tool connector.

7.13.2.3.3 Controls and instrumentation

Control system and data gathering instrumentation conduits may pass through the tree running tool body. Specific designs and selection of component materials are the responsibility of the manufacturer.

7.13.2.4 Tree guideframe interface

The tree cap running tool shall have a guidance structure that interfaces with the tree cap or tree guideframe to provide initial orientation and alignment when required. If a guidance system is used, it shall be designed to provide alignment to protect seals and seal surfaces from damage in accordance with the manufacturer's written specification.

7.13.2.5 Secondary release

Hydraulically actuated tree cap running tools shall be designed with a secondary release method which may be hydraulic or mechanical. ROV/diver/remote tooling or through installation string, should be considered. Hydraulic open and close piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if needed for the secondary release to function.

7.13.2.6 Position indication

Remotely operated tree cap running tools shall be equipped with an external position indicator suitable for observation by diver/ROV.

7.13.3 Testing

7.13.3.1 General

The following test procedure applies to both mechanical and hydraulic tree cap running tool connectors.

7.13.3.2 Factory acceptance testing

All wellbore pressure-containing/controlling components shall comply with the hydrostatic test requirements of 5.4. Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.3.

After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test in accordance with the requirements given in 7.9.4.2.3.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

7.14 Tree guide frame

7.14.1 General

The tree guide frame interfaces with the PGB to guide the subsea tree onto the subsea wellhead. The frame may also provide a structural mounting for piping, flowline connection, control interfaces, work platforms, anodes, handling points, ROV docking/override panels, and structural protection both on surface and subsea, for tree components. The tree guide frame will provide an envelope and structural mounting for the control pod when used. The envelope will allow sufficient space for control pod installation, retrieval and access. The above also applies if a retrievable choke module is located on the subsea tree. The design should consider protection of actuators and critical components from dropped objects, trawl boards, etc. when applicable.

7.14.2 Design

7.14.2.1 Permanent guide base interface

The tree guide frame shall interface with standard PGB dimensions (refer to Figure 9). The guide funnels shall be hollow and slotted to permit installation of guidelines. Guideline gates are required to contain the guidelines within the funnels at the top and bottom of the frame. The design of the gates should consider ease of opening and closure and eliminate the risk of the guidelines snagging during installation or retrieval. Orientation of the guide line slots in the post shall be specified by the manufacturer.

7.14.2.2 Handling

Padeyes will be provided on the guide frame to allow handling of the assembled tree complete with test skid.

7.14.2.3 Loads

The guide funnels shall be capable of supporting the full weight of the stacked tree, running tool and EDP, or alternatively landing pads may be provided. Depending on the environment in which the tree is to be used, the structure may be required to extend from the bottom of the tree to the top of the tree to provide protection from installation loads and snag loads. As a minimum, the following loads, where appropriate, shall be considered and documented by the manufacturer when designing the tree guide frame:

— ballast;

— guide line tension;

— flowline reaction loads;

— snag loads;

— dropped object loads;

— installation load and intervention loads;

— handling and shipping loads.

7.14.2.4 Intervention interfaces

Provision for all ROV intervention to relevant ROV functions shall be provided. Subsea intervention fixtures attached to the tree guide frame shall be in accordance with a recognized industry standard for ROV[5]. Design and operation of ROV intervention on subsea hardware. The frame design shall not impede access or observation, as appropriate, by divers/ROV of tree functions and position indicators.

7.14.3 Testing

Interface testing shall be conducted on the guide frame by installing the frame on a four post 1 829 mm (6,0 ft) radius test stump, or PGB in compliance with this part of ISO 13628. A wellhead connector and mandrel or other centralizing means shall be used during the test. Test results shall be in accordance with the manufacturer's written specifications.

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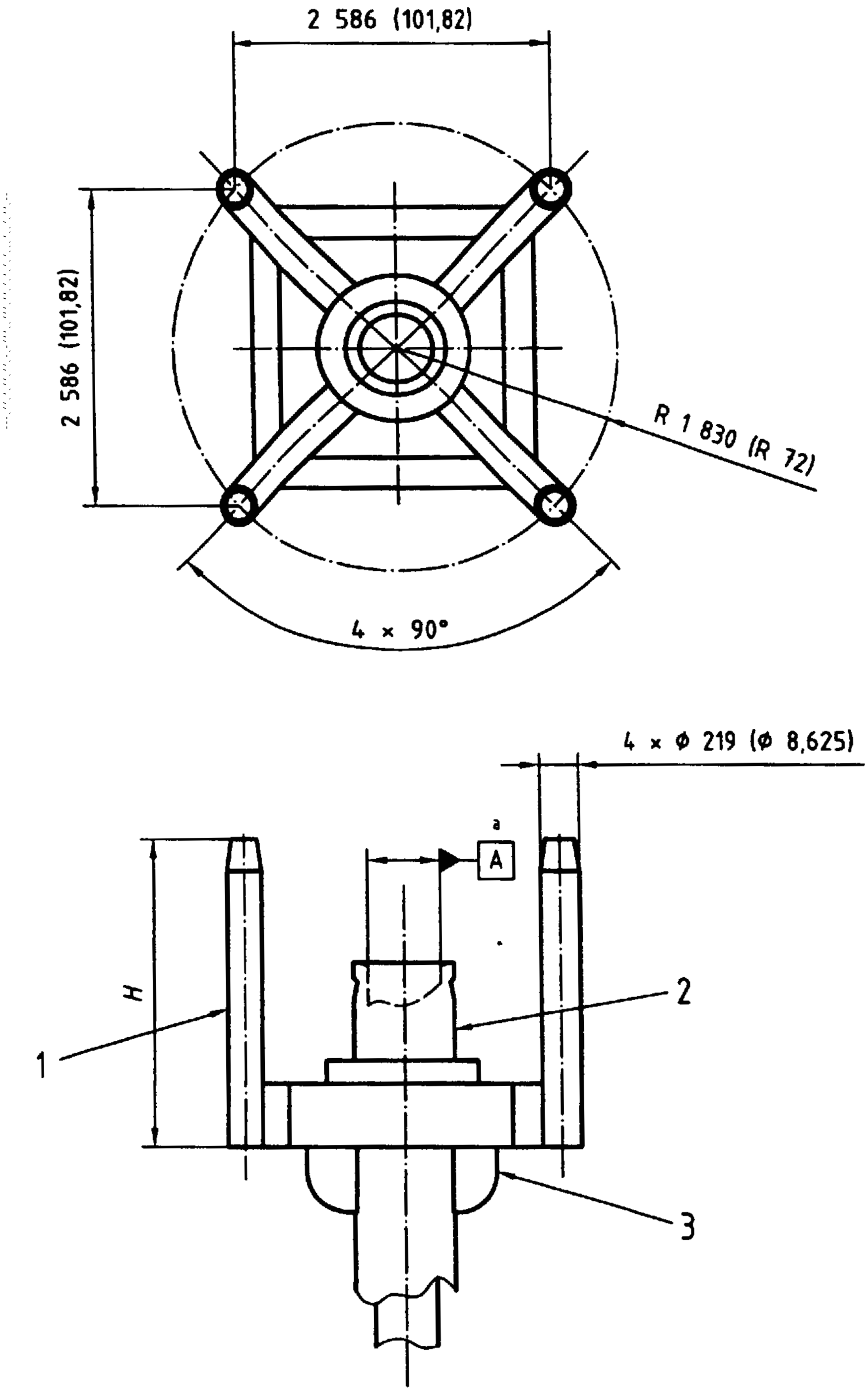
5) For the purposes of this part of ISO 13628, the industry standard will be replaced by ISO 13628-8 when the latter becomes publicly available.

Dimensions in millimetres
(inches in parentheses)



Key

1 Guide post
2 Subsea wellhead housing
3 PGB
[a] See note 1.

NOTES

1 Guide post positional tolerances are determined relative to the wellhead housing bore (datum A); method of measurement to be specified by the manufacture.

2 Cumulative tolerances between all interfacing components must be less than or equal to the positional tolerance shown.

3 Dimension H to be 2 500 mm (8 ft) min.

Figure 9 — Permanent guide base and guide post dimensioning and tolerancing

7.15 Tree running tool

7.15.1 General

The function of a hydraulic or mechanical tree running tool is to suspend the tree during installation and retrieval operations from the subsea wellhead, and to connect to the tree during workover operations. It may also be used to connect the completion riser to the subsea tree during installation, test or workover operations. A subsea wireline/coil tubing BOP or other tool packages may be run between the completion riser and tree running tool. The need for soft landing systems should be evaluated.

7.15.2 Operating criteria

The manufacturer or purchaser shall specify the operating criteria for which the tree running/retrieval tool is designed.

NOTE Tree running/retrieval tools should be designed to be operable in the conditions/circumstances expected to exist during tree running/retrieving operations and well re-entry/workover operations. Specific operating criteria (design loads and angle limits etc.) should consider the maximum surface vessel motions and resulting maximum running string tensions and angles which may occur.

7.15.3 Loads

As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree running tool.

— internal and external pressure;

— pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed, unless relief is provided as described in 5.1.2.1.1);

— mechanical preloads;

— riser bending and tension loads;

— environmental loads;

— fatigue considerations;

— vibration;

— mechanical installation (impact) loads;

— hydraulic coupler thrust and/or preloads;

— thermal expansion (trapped fluids, dissimilar metals);

— installation/workover overpull;

— corrosion.

The manufacturer shall specify the loads/conditions for which the equipment is designed. The manufacturer shall document the load/capacity for their tree running tool connector using the load chart format illustrated in Figure 8, which relates pressure to allowable bending moment for various tensions. The manufacturer shall state whether the basis of the graphs are stress limits or seal separation limits.

7.15.4 Tree interface

7.15.4.1 General

The tree running tool interfaces with the tree upper connection. This interface shall be designed for emergency release at a running string departure angle as specified by the manufacturer or purchaser. This release must not cause any damage to the subsea tree such that any other performance requirement is not met.

The tree interface consists of four main component areas:

— locking profile and connector;

— re-entry seal (where applicable);

— extension subs or seals (where applicable);

— controls and instrumentation (where applicable).

For use with dynamically positioned rigs it is particularly important that the connector has high angle release capability and that the connector can be quickly unlocked. In some systems these requirements may be met in the EDP connector design. The manufacturer and/or purchaser shall specify the angle and unlocking time.

7.15.4.2 Locking profile and connector

The tree running tool shall land and lock onto the locking profile of the tree re-entry spool and shall withstand separating forces resulting from applied mechanical loads and the rated working pressure of the tree as specified by the manufacturer. The tree running tool connector shall meet functional requirements set forth in 7.7.3

Means shall be provided to prevent trapped fluid from interfering with make-up of the hydraulic or mechanical connector.

7.15.4.3 Re-entry seal

An additional sealing barrier to the environment may be included in the interface between the tree running tool interface. This seal encircles all bore extension subs and may enclose hydraulic control circuits. The rated working pressure of this gasket shall be specified by the manufacturer.

The pressure-containing capability of this gasket shall be at least equal to the tree rated working pressure or the maximum anticipated control pressure of the downhole safety valve, whichever is greater, if the SCSSV control circuit(s) is encapsulated by this seal, unless relief is provided as described in 5.1.2.1.1.

7.15.4.4 Extension subs or seals

Extension subs or seals (if used) shall engage mating surfaces in the upper tree connection for the purpose of isolating each bore. The seal mechanism shall be either metal-to-metal seals or redundant resilient seals.

In multi-bore applications which use a re-entry seal as described in 7.15.4.3, each extension sub or seal shall be designed to withstand an external pressure as specified by the manufacturer.

The pressure rating of the extension sub or seal shall be equal to the working pressure rating of the tree, or if enclosed, the maximum anticipated control pressure of the SCSSV line, whichever is greater, unless relief is provided as described in 5.1.2.1.1. Each extension sub or seal (if used) shall be designed to an internal pressure rating equivalent to the rated working pressure of the tree.

7.15.4.5 Controls and instrumentation

Control system and data gathering instrumentation conduits may pass through the tree running tool body. Specific designs and selection of component materials are the responsibility of the manufacturer.

7.15.4.6 Running string interface

The tree running tool may interface with one or more of the following:

— the drilling riser system;

— subsea WCT-BOP or wireline cutter;

— completion riser or stress joint;

— *drill* pipe or tubing running string;

— LRP.

7.15.4.7 Tree guideframe interface

The tree running tool shall have a guidance structure that interfaces with the tree guideframe or extended PGB posts, to provide initial orientation and alignment. If a guidance system is used, it shall be designed to provide alignment to protect seals and seal surfaces from damage in accordance with the manufacturer's written specification. Where guidance and orientation is dependent on extended PGB guide posts, alternative means of orienting the tree running tool during surface installation/testing shall be considered to prevent damage to the seal bores during installation.

7.15.4.8 Control system interface

The tree running tool and/or the workover control interface normally transfers control of the subsea tree from the normal surface production control point to the workover control system.

7.15.4.9 Secondary release

Hydraulically actuated tree running tool connectors shall be designed with a secondary release method. ROV/diver/remote tooling or through installation string should be considered. Hydraulic open and close control line piping shall be positioned to allow cutting by diver/ROV or contain a means to vent hydraulic lock pressure if needed for the secondary release to function.

7.15.4.10 Position indication

Remotely-operated tree running tool connectors shall be equipped with an external position indicator suitable for observation by diver/ROV.

7.15.5 Materials

Tree running tool portions which may be exposed to wellbore fluids shall be made of materials conforming to 6.2 and to ANSI/NACE MR0175.

7.15.6 Factory acceptance testing

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.2.

After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test in accordance with the requirements given in 7.9.4.2.2.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

7.16 Tree piping

7.16.1 General

The term tree piping is used to encompass the requirements for all pipe, fittings, or pressure conduits, excluding valves and chokes, from the vertical bores of the tree to the flowline connection(s) leaving the subsea tree. The piping may be used for production, pigging, monitoring, injection, service or test of the subsea tree.

Inboard tree piping is upstream of the first tree wing valve(s). Outboard tree piping is downstream of the first tree wing valve, and upstream of the flowline connector.

Where tree piping extends beyond the tree guide frame envelope, protection shall be provided. Access for diver/ ROV shall be considered during the design of flowspool routing.

7.16.2 Design

7.16.2.1 Allowable stresses

Outboard-tree piping shall conform to the requirements of an existing documented piping code such as ANSI/ASME B31.4, ANSI/ASME B31.8 or ANSI/ASME B31.3. As a minimum, the design rated working pressure of the outboard piping shall be equal to the rated working pressure of the tree. Inboard piping shall be designed in accordance with 5.1. In all cases, the following shall be considered:

— allowable stress at working pressure;

— allowable stress at test pressure;

— external loading;

— tolerances;

— corrosion/erosion allowance;

— temperature;

— wall thinning due to bending;

— vibration.

7.16.2.2 Operating parameters

Operating parameters for tree piping shall be based on the service, temperature, material, and external loading on each line. Tree piping may be designed to flex to enable connectors to stroke or to compensate for manufacturing tolerances. Special consideration shall be given to piping downstream of chokes, due to possible high fluid velocities and low temperatures.

7.16.2.3 Tree piping flowloops

Tree piping flowloops may be fabricated using forged fittings or pre-bent sections, or may be formed in a continuous piece. Either "cold" bending or "hot" bending may be used. Bends which are to be used in H_2S service shall conform to the requirements of ANSI/NACE MR0175. Quenched and tempered pipe and tube that is hot bent shall be requenched and tempered after bending in accordance with the manufacturer's written specification. Pipe bending tolerances shall conform to the requirements of the PFI Standard ES-24.

7.16.2.4 TFL tree piping flowloops

TFL piping flowloops shall also be designed in accordance with API RP 17C for TFL pumpdown systems and 7.10.

7.16.2.5 Pigging

The manufacturer shall document the pigging capability of tree piping.

7.16.2.6 Flowline connector interface

The tree piping and flowline connector when required by the system shall be designed to allow flexibility for connection in accordance with the manufacturer's written specification. Alternatively the flexibility may be built into the interface piping system. In the connected position, the combination of induced pipe tension, permanent bend stress, and the specified operating pressure shall not exceed the allowable stress as defined in 7.16.2.1. Stresses induced during make-up may exceed the level in 7.16.2.1, but shall not exceed material minimum yield stress.

7.16.2.7 Pressure/temperature transducer and chemical injection penetrations

Penetrations located on inboard piping shall be equipped with flanged outlets which conform to 7.1 or 7.4.

Penetrations located on outboard piping may be either flanged, threaded, or weld on bosses. Threaded connections shall conform to 7.3, flanged connections shall conform to 7.1 or 7.4, and weld-on bosses shall conform to ANSI/ASME B16.11.

Safeguarding of the transducer connections shall be provided by either locating the ports in protected areas or by fabricating protective guards or covers.

7.16.3 Materials

Materials for inboard piping shall conform to 5.2. Material for outboard pipe and pipe fittings shall conform to the requirements of the applied design code, e.g. wall thickness calculated using ANSI/ASME B31.3 requires the use of ANSI/ASME B31.3 allowable stresses.

7.16.4 Welding

Welding of inboard piping shall be in accordance with 5.3. Welding of outboard piping shall conform to the applicable piping code or 5.3, whichever is appropriate.

7.16.5 Testing

Hydrostatic proof testing shall be conducted on all tree piping. If the tree piping test pressure exceeds the tree rated working pressure, then the tree piping may be subjected to separate hydrostatic shell tests as individual spool pieces rather than as complete assemblies. Test pressures and method for testing inboard piping shall conform to the requirements of 5.4. Outboard tree piping shall be tested in accordance with the flowline code as specified in 7.16.2.1.

7.17 Flowline connector systems

7.17.1 General — Types and uses

This subclause covers the tree-mounted flowline connector systems which are used to connect subsea flowlines/umbilicals to subsea trees. Electrical connection and component equipment is beyond the scope.

The flowline connector system may utilise various installation methods, such as first end or second end connection methods as described in ISO 13628-1. Flowline connectors may be either diverless or diver-assisted and may utilize guide lines/guide posts to provide guidance and alignment of the equipment during installation.

7.17.2 Flowline/wellhead connector support frame

7.17.2.1 General

The flowline connector support frame shall provide an attachment point to the subsea tree and/or subsea wellhead of the flowline connector mechanism. The support frame shall be attached to the subsea wellhead housing, the PGB, the tree and/or tree frame, the template frame (if applicable), or other structural member suitable for accommodating all expected loading conditions.

7.17.2.2 Design

7.17.2.2.1 Loads

The following loads shall be considered and documented by the manufacturers when designing the flowline connector support frame:

— flowline pull-in, catenary, and/or drag forces during installation;

— flowline alignment loads (rotational, lateral, and axial during installation);

— flowline operational reaction loads due to residual stresses, flowline weight, thermal expansion/contraction and operational/environmental effects;

— flowline reaction/alignment loads when the tree is removed for service;

— overloads, such as snag loads, mudslides, etc.

7.17.2.2.2 Dimensions

The flowline connector support frame shall be designed to avoid interfering with the BOP stack when on the wellhead housing after the flowline connector support frame is installed.

7.17.2.2.3 Functional requirements

The flowline connector support frame shall react all loads imparted by the flowline and umbilical into a structural member to ensure that:

— tree valves and/or tree piping are protected from flowline/umbilical loads which could damage these components;

— alignment of critical mating components is provided and maintained during installation;

— tree can be removed and replaced without damage to critical mating components.

7.17.3 Flowline connectors

7.17.3.1 General

The flowline connector and its associated running tools provide the means for joining the subsea flowline(s) and/or umbilical(s) to the subsea tree. In some cases, the flowline connector also provides means for disconnecting and removing the tree without retrieving the subsea flowline/umbilical to the surface.

Flowline connectors generally fall into three categories:

a) manual connectors operated by divers or ROVs;

b) hydraulic connectors with integral hydraulics similar to subsea wellhead connectors;

c) mechanical connectors with the hydraulic actuators contained in a separate running tool.

7.17.3.2 Design

Flowline connectors shall have a rated working pressure equal to the rated working pressure of the tree. The design of flowline connectors shall be in accordance with 5.1 with the exception that the pressure testing shall comply with 5.4 for a connector mounted inboard of the first wing valve. For a connector mounted outboard of the first wing valve, pressure testing shall comply with an existing documented piping code ANSI/ASME B31.4, ANSI/ASME B31.8 or ANSI/ASME B31.3.

7.17.3.3 Loads

The following loads shall be considered and documented by the manufacturer when designing the flowline connector and associated running tools:

— flowline pull-in, catenary, and/or drag forces during installation;

— flowline alignment loads (rotational, lateral, and axial) during installation;

— flowline reaction loads due to residual stresses, flowline weight, thermal expansion/contraction and operational/environmental effects;

— reactions from environmental loads on flowline connector running/retrieval and maintenance tools;

— flowline reaction/alignment loads when the tree is pulled for service;

— flowline/umbilical overloads;

— internal and external pressures (operational and hydrostatic/gas tests).

The flowline connector shall ensure sealing under all pressure and external loading conditions specified.

When actuated to the locked position, hydraulic flowline connectors shall remain self-locked without requiring hydraulic pressure to be maintained. Connectors shall be designed to prevent loosening due to cyclic installation and/or operational loading. This shall be achieved by a mechanical locking system or backup system or other demonstrated means. Mechanical locking devices shall consider release in the event of malfunction.

7.17.3.4 Dimensions

The dimensions of the flowline connectors flow passages should be compatible with the drift diameters of the flowlines.

If TFL service is specified, the TFL flow passage geometry shall meet the dimensional requirements of API RP 17C for TFL pumpdown systems.

If pigging capability is specified, the flowline connector flow passages should be configured to provide transitions and internal geometry compatible with the type of pig(s) specified by the manufacturer.

The end connections used on the flowline connector (flanges, clamp hubs, or other types of connections) shall comply with 7.1 through 7.6. Preparations for welded end connections shall comply with 7.1.2.

The termination interface between the flowline connector and the flowline shall conform to the requirements of a documented design code such as ANSI/ASME B31.3, ANSI/ASME B31.4, or ANSI/ASME B31.8.

7.17.3.5 Functional requirements

The flowline connector and/or its associated running tool(s) should provide positioning and alignment of mating components such that connection can be accomplished without damage to sealing components or structural connection devices. Seals and sealing surfaces should be protected during flowline installation operations.

Metal-to-metal seals are preferred for primary seals on flowline connectors. Where metal-to-metal primary seals are not utilised, redundant seals (primary plus backup) shall be provided.

Where multiple bore seals are enclosed within an outer environmental or secondary seal, bi-directional bore seals shall be provided to prevent cross-communication between individual bores.

The flowline connection system shall provide means for pressure testing the flowline and/or umbilical connections following installation and hook-up.

The flowline connector design should provide a means to disconnect and remove the tree (and to subsequently replace it) without the need to retrieve the subsea flowline/umbilical to the surface. Consideration should be given to preventing seawater from entering into the flowline when separated from the tree.

The flowline connector shall have the same working pressure rating as the subsea tree. Means shall be provided for pressure testing the tree and all its associated valves and chokes without exceeding the test pressure rating of the flowline connector.

The flowline connector shall have the same temperature rating as the subsea tree.

7.17.4 Testing

7.17.4.1 General

This subclause deals with testing of the flowline connector system which includes the flowline connector support frame, the flowline connector, the flow loops, and associated running/retrieval and maintenance tools.

7.17.4.2 Performance verification testing

Tests shall be conducted to verify the structural and pressure integrity of the flowline connector system under the rated loads specified by the manufacturer in accordance with 6.1. Such tests shall also take into consideration:

— simulated operation of all running/retrieval tools under loads typical of those expected during actual field installations;

— simulated pull-in or catenary flowline loads (as applicable) during flowline installation and connection;

— removal and replacement of primary seals for flowline connectors for remotely replaceable seals;

— functional tests of required running/retrieval and maintenance tools;

— maximum specified misalignment.

The manufacturer shall document successful completion of the above tests.

7.17.4.3 Factory acceptance testing

a) **Structural components**

All mating structural components shall be tested in accordance with the manufacturer's written specification for fit and function using actual mating equipment or test fixtures.

b) **Pressure-containing components**

For flowline connectors mounted outboard of the first wing valve, all pressure-containing components shall be hydrostatically tested in accordance with the specified flowline code. For flowline connectors mounted inboard of the first wing valve, hydrostatic tests shall be conducted in accordance with 5.4.

Components having multiple bores or ports shall have each bore or port tested individually. Multiple bores enclosed within an outer environmental or secondary seal shall be tested in the reverse direction at the lowest working pressure rating of any enclosed seal to verify that there is no intercommunication between bores.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.2.

After final assembly, the connector shall be tested for proper operation and interface in accordance with the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test in accordance with the requirements given in 7.9.4.2.2.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, and locking mechanisms. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

c) **Running tools**

All running/retrieval and maintenance tools shall be tested in accordance with the manufacturer's written specification for fit and function with mating equipment or test fixtures.

7.17.5 *In-situ* testing

In-situ testing is beyond the scope of this part of ISO 13628. However, if *in-situ* testing of flowlines is required at pressures above the tree rated working pressure, a test isolation valve with a higher working pressure than the tree may be required.

7.18 Control pod running tool

7.18.1 General

The control pod and its running/retrieval and testing tools are used to install, remove, and test the subsea components of the production control system. The design of these tools is dependent upon the type of control system utilized and the configuration of the subsea hardware which may include a control modular and hydraulic accumulator system.

Tools for running and retrieving the equipment will generally require hydraulic control functions to operate lockdown devices, hydraulic or electrical connector actuation mechanisms, and means for connection to and release from the control package. Additional equipment may be included to provide the capability for inplace troubleshooting or fault isolation.

The tools may be run on a completion riser, drill pipe, wire rope or umbilical.

NOTE The above requirements also apply if a retrievable choke module is located on the subsea tree. In cases where both the control pod and the choke are retrievable, a common tool for retrieving/re-installing both modules should be considered.

7.18.2 Design

7.18.2.1 Operating parameters

The manufacturer shall specify the operating criteria for which the control package running/retrieval tool is designed.

NOTE Control package running/retrieval and testing tools should be designed to be operable under the conditions/circumstances expected to exist during running/retrieving operations and workover operations. Specific operating criteria (design loads and angle limits, etc.) should consider the maximum surface vessel motions and resulting maximum running string tensions and angles which may occur.

7.18.2.2 Running tool interface

The manufacturer shall document the maximum combined loads at which the running tool can remain connected without damage to the extent that any other performance requirement is not met. The running tool shall be designed for emergency release at running string tensions and departure angles as specified and documented by the manufacturer.

Control and/or test connections which pass through this interface shall retain pressure integrity under the maximum combined loads rating.

7.18.2.3 Control package guideframe

If used, guideframes on the control package and/or running tool shall be designed to provide for the alignment of mating components during installation and removal in accordance with the manufacturer's written specification.

7.19 Flowline connector support frame running/retrieving tools and related system interfaces

7.19.1 General

This subclause covers tools used to install and retrieve flowline connector support frames which are not installed integral with other equipment.

7.19.2 Design

7.19.2.1 Operating criteria

The manufacturer shall document the operating criteria for which the flowline connector support frame running/retrieval tools and related system interfaces are designed.

NOTE Flowline connector support frame running/retrieval and testing tools should be designed to be operable in the conditions/circumstances expected to exist during running/retrieving operations and workover operations. Specific operating criteria (design loads and angle limits, etc.) should consider the maximum surface vessel motions and resulting maximum running string tensions and angles which may occur.

7.19.2.2 Loads and component strength

As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the flowline connector support frame running tool:

— internal and external pressure;

— pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed);

— mechanical preloads;

— running string bending and tension loads;

— environmental loads;

— fatigue considerations;

— vibration;

— mechanical installation (impact) loads;

— hydraulic coupler thrust and/or preloads;

— installation/workover overpull;

— corrosion.

The manufacturer shall specify the loads/conditions for which the equipment is designed. The manufacturer shall document the load/capacity for their running tool.

7.19.2.3 Running tool interfaces

The flowline connector support frame running tool shall be capable of connection, function and disconnection at the maximum combined loads, as specified in the above paragraph.

Control and/or test connections which pass through the interface shall retain pressure integrity at the maximum combined load rating.

7.19.2.4 Guidance and alignment

If used, guidance structures shall be designed to provide for alignment of mating components during installation and removal in accordance with the manufacturer's written specification.

7.19.2.5 Remote intervention equipment

Remote intervention fixtures shall be designed in accordance with requirements of a recognized industry standard for ROV[6] or ISO 13628-9.

7.20 Tree-mounted hydraulic/electric control interfaces

7.20.1 General

Tree-mounted hydraulic/electric control interfaces covered by this part of ISO 13628 include all pipes, hoses, electric cables, fittings, or connectors mounted on the subsea tree, flowline base, or associated running/retrieving tools for the purpose of transmitting hydraulic or electric signals or hydraulic or electric power between controls, valve actuators and monitoring devices on the tree, flowline base or running tools and the control umbilical(s) or riser paths.

7.20.2 Design

7.20.2.1 Pipe/tubing/hoses

Allowable stresses in pipe/tubing shall be in conformance with ANSI/ASME B31.3. Hose design shall conform to ANSI/SAE J517. Design shall take into account:

— allowable stresses at working pressure;

— allowable stresses at test pressure;

— external loading;

— collapse;

— manufacturing tolerances;

— fluid compatibility;

— flow rate;

— corrosion/erosion;

— temperature range;

— vibration.

7.20.2.2 Size and pressure

All pipe/tubing/hose shall be 6,0 mm (1/4 in) nominal diameter, or larger. Sizes and pressure ratings of individual tubing runs shall be determined to suit the functions being operated. Consideration shall be given to preventing restrictions in the control tubing which may cause undesirable pressure drops across the system. However general tree functions shall be rated at 20,7 MPa (3 000 psi) or as documented by the manufacturer. Injection lines, connector/gasket seals test lines and pressure monitor lines shall be rated at the working pressure of the tree and the SCSSV lines shall be rated at the specified SCSSV operating pressure. Standard SCSSV operating pressures are 34,5 MPa (5 000 psi), 51,7 MPa (7 500 psi), 86,3 MPa (12 500 psi) or 120,7 MPa (17 500 psi) .

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6) For the purposes of this part of ISO 13628, the industry standard will be replaced by ISO 13628-8 when the latter becomes publicly available.

7.20.2.3 Envelope

All pipe/tubing/hose/electric cable shall be within the envelope defined by the guideframes of the tree, running/retrieving tool, or the flowline base.

7.20.2.4 Routing

The routing of all pipe/tubing/hose/electric cable shall be carefully planned and it should be supported and protected to minimise damage during testing, installation/retrieval, and normal operations of the subsea tree. Free spans shall be avoided and where necessary it shall be supported and/or protected by trays/covers. Tubing running to hydraulic tree connectors, running connectors and flowline connectors, shall be accessible to divers/ROV such that it can be disconnected, vented or cut, in order to release locked in fluid and allow mechanical override.

Electrical cables shall be routed such that any water entering the compensated hoses will move away from the end terminations by gravity. Electrical signal cables shall be screened/shielded to avoid cross talk and other interferences.

7.20.2.5 Hydraulic end fittings

Hydraulic couplers. End fittings and couplers shall meet or exceed requirements of the existing piping code used for the piping/tubing/hose design in 7.20.2.1. Tubing runs shall be planned so as to use the minimum number of fittings. Welding may be used to join tubes at the manufacturers discretion.

The coupling stab/receiver plate assembly shall be designed to withstand rated working pressure applied simultaneously in every control path without deforming to the extent that any other performance requirement is effected in accordance with the manufacturer's written specification. In addition, when non-pressure balanced control couplers are used, the manufacturer shall determine and document the rated water depth at which coupler plate/junction plate can decouple the control couplers without deformation damage to the plate assemblies. The manufacturer shall determine and document the force required for decoupling at rated water depth.

Proprietary coupler stab and receiver plate designs shall meet the test requirements set forth in 7.20.5.

7.20.2.6 Electrical connectors

Electrical connection interfaces made-up subsea shall feature pressure compensated chambers or housings to prevent the ingress of water or external contaminants. Conductive pin type connectors shall allow the male contact pins to be wiped prior to entry into an oil filled pressure compensated contact chamber. The retrievable half of conductive type electrical connectors shall contain all seals, primary compensation chambers, penetrators, springs, etc.

7.20.2.7 Control line stabs/couplers

As a minimum, control line stabs for the SCSSV, production master valve(s), production wing valve, annulus valve and workover valve shall be designed so as not to trap pressure when the control stabs are separated. The control stabs shall be designed to minimize seawater ingress when connected/disconnected. They shall be capable of disconnection at the rated internal working pressure, without detrimental effects to the seal interface. The half containing the seals shall be located in the retrievable assemblies. In addition to the internal working pressure, the control stabs shall be designed to withstand external hydrostatic pressure at manufacturer's rated water depth.

Stabs shall be capable of sealing at all pressures within their rating, in both the mated and un-mated (non-vented type) condition.

7.20.2.8 Alignment/orientation of receiver plates

Multi-port hydraulic receiver plates, as used at the control pod, tree cap, EDP, LRP, etc. shall have an alignment system to ensure correct alignment of hydraulic couplers prior to engagement of their seals. The stabs couplers shall be mounted in a manner to accommodate any misalignment during make-up.

7.20.3 Assembly practice

7.20.3.1 Cleanliness during assembly

Practices should be adopted during assembly to maintain tubing/piping/fittings cleanliness.

7.20.3.2 Flushing

After assembly of all tubing runs and hydraulically actuated equipment, it should be flushed to meet the cleanliness requirements of NAS 1638-64. Class of cleanliness to be in accordance with the manufacturer's written specification. Final flushing operations shall use a hydraulic fluid compatible with the fluid to be used in the field operations. Equipment shall be supplied filled with hydraulic fluid. Fittings, hydraulic couplings etc. shall be blanked off after completion of flushing/testing to prevent particle contamination during storage and retrieval.

7.20.4 Materials

7.20.4.1 Corrosion

Pipe/tubing and end fittings, connectors and connector plates shall be made of materials which will withstand atmospheric and seawater corrosion.

Pipe/tubing/hoses which wellbore fluids may come in contact with shall be made from materials compatible with the well bore fluids.

7.20.4.2 Seal materials

Seal materials shall be suitable for the type of hydraulic control fluid to be used in the system. Seals which may come into contact with well bore fluids shall be made of materials compatible with the well bore fluids.

7.20.5 Testing

7.20.5.1 Pipe/tubing

Shall be of a design which has been performance verification tested in conformance with ANSI/ASME B31.3. Hoses shall be of a design which has been performance verification tested in conformance to ANSI/SAE J343. Performance verification testing for hoses shall be repeated for hose designs whose verification test are more than 5 years old.

Testing of assembled pipe/tubing/hose and end fittings, connectors, and connector plates exposed to production pressure shall conform to 5.4, except that the test pressure shall not exceed the test pressure of the lowest pressure rated component in the system. Testing of assembled pipe/tubing/hose and end fittings, connectors, and connector plates carrying control fluid shall be in accordance with ANSIASME B31.3.

7.20.5.2 Stab/receiver plate assembly

This shall be tested to rated working pressure applied simultaneously in every control path in accordance with the manufacturer's written specification.

7.20.6 Connector plate marking

Each connector plate shall be permanently marked with the following minimum information.

a) Its part number and the part number of the connector plate it is designed to mate with.

EXAMPLE 1

— (part number) TO MATE WITH (part number of mating plate);

b) Path designation numbers or letters identifying each path/connector in the connector plate assembly (hoses and tubing should be marked accordingly).

c) Rated operating pressures of each path passing through the connector plate assembly.

EXAMPLE 2

— 6 X 20,7 MPa (3 000 psi) - PATHS 1 - 6;

— 4 X 10,3 MPa (1 500 psi) - PATHS 7, 8, 11, 12;

— 2 X 34,5 MPa (5 000 psi) - PATHS 9, 10.

7.21 Subsea chokes and actuators

7.21.1 General

This subclause covers subsea chokes, actuators, and their assemblies used in subsea applications. It provides requirements for the choke/actuator assembly performance standards, sizing, design, materials, testing, marking, storage and shipping. Subsea choke applications are production, gas lift and injection. Chokes are a special kind of control valve designed to control flow or pressure and are not intended to be used as shut off valves.

Subsea chokes are considered high wear items and therefore allowances for choke maintenance should be considered. Subsea chokes may be designed to allow change out of flow bean or trim by divers or ROV/running tools. Alternatively the complete choke may be designed for retrieval. In both cases the system design shall allow isolation prior to retrieval, and testing following re-installation. Placement of the choke should allow adequate spacing for retrieval, and diver/ROV override operations. Electrical actuators are acceptable for subsea chokes, however their detailed design guide lines are outside the scope of this part of ISO 13628.

7.21.2 Subsea chokes

7.21.2.1 General

7.21.2.1.1 Adjustable chokes

Adjustable chokes have an externally controlled variable-area orifice trim and may be coupled with an orifice area indicating mechanism.

7.21.2.1.2 Positive chokes

Positive chokes accommodate replaceable parts having a fixed orifice dimension, commonly known as flow beans.

7.21.2.1.3 Orifice configuration

"Orifice configuration" for chokes, sometimes referred to as "trim," in control valve terminology, describes the internal components which determine flow area through the choke. A variety of orifice configurations are available for chokes. Five of the most common adjustable orifice configurations are: rotating disc, needle and seat, plug and cage, sliding sleeve and seat, and multistage. Examples of orifice configurations are shown in Figure 10. Optimum orifice configuration is selected on the basis of operating pressures, temperatures and flow media.

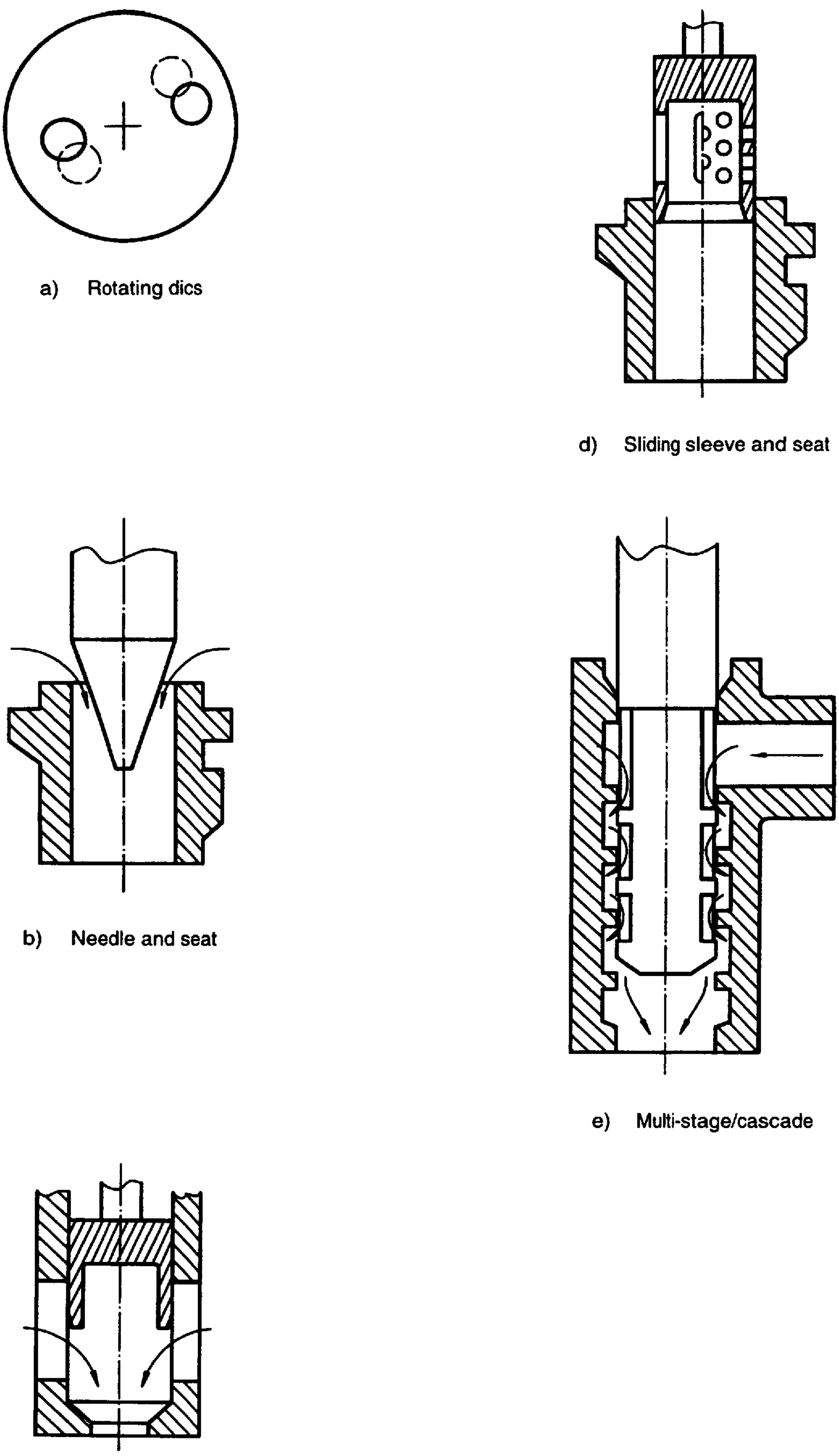
7.21.2.1.4 Choke capacity

The manufacturer shall document flow rate based on maximum orifice, pressure, temperature and fluid media.

The choke orifice diameter shall be sized for anticipated or actual production flow rate and fluid conditions (pressures and temperature). The information shown in clause 12 for purchasing guide lines shall be supplied to the choke manufacturer for sizing of the choke.

7.21.2.2 Design

Subsea chokes shall be designed in accordance with the general design requirements of 5.1 and of ISO 10423, as required for PR2.



a) Rotating dics

b) Needle and seat

c) Plug and cage

d) Sliding sleeve and seat

e) Multi-stage/cascade

Figure 10 — Choke common orifice configurations

7.21.2.2.1 Design and operating parameters

Manufacturers shall document the design and operating parameters of the choke as follows.

Design and operating parameters of subsea chokes:

- — maximum pressure rating;
- — maximum orifice size;
- — temperature rating;
  - — maximum,
  - — minimum;
- — PSL level;
- — material class;
- — type of choke;
  - — positive (fixed, insert type),
  - — adjustable choke with handwheel,
  - — adjustable choke prep. for manual actuator,
  - — adjustable choke prep. for hydraulic actuator,
  - — end connections,
  - — size and pressure rating,
  - — ring gasket size (if applicable),
  - — type of operation,
  - — ROV,
  - — ROT,
  - — diver assist,
  - — size of socket or hex (if applicable),
  - — handwheel diameter;
- — external pressure rating (maximum) or water depth;
- — maximum flow rate.

7.21.2.2.2 Pressure rating

Subsea chokes with MRWPs of 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi) are covered by this part of ISO 13628.

For chokes having end connections with different pressure ratings, the rating of lowest rated pressure-containing part shall be the rating of the subsea choke. The rated working pressure of the subsea choke shall be equal to or greater than the rated working pressure of the subsea tree.

7.21.2.2.3 Temperature rating

All pressure-containing components of subsea chokes shall be designed for the temperature ratings specified in 5.1.2.2. For subsea chokes, the maximum temperature rating is based on the highest temperature of the fluid which may flow through the choke. Subsea chokes shall have a maximum temperature rating equal to or greater than the tree. The minimum temperature rating of subsea chokes shall be in accordance with the manufacturer's written specifications.

7.21.2.2.4 End connections

End connections for chokes shall be as specified in 7.1 to 7.6.

7.21.2.2.5 Vent requirements

Subsea chokes shall be designed to allow trapped pressure to be vented prior to releasing and during landing of the body-to-bonnet connector on adjustable chokes and the body-to-cap connector on positive chokes.

7.21.2.2.6 External pressure requirements

Subsea chokes shall be designed to withstand external hydrostatic pressure at the maximum rated water depth.

7.21.2.3 Choke testing

7.21.2.3.1 Factory acceptance test

Hydrostatic testing of subsea chokes shall be in accordance with 5.4. For FAT data sheet for subsea choke, refer to Tables 16 and 17.

Table 16 — FAT — Subsea choke with hydraulic operator operational test (choke with hydraulic operator)

Test No.	Cycle No.	Choke pressure	Hydraulic pressure Required to:		Verification that the choke operated smoothly and without backdriving					
					During opening			During closing		
			Close shoke	Open choke	Yes	No	Witness	Yes	No	Witness
1	1	Atmospheric								
	2	Atmospheric								
	3	Atmospheric								
2	1	Working pressure								
	2	Working pressure								
	3	Working pressure								
	4	Working pressure								
	5	Working pressure								

Table 17 — FAT — Subsea choke with mechanical operator and/or hydraulic operator with mechanical override operational test — Choke and manual operator choke and hydraulic operator with manual override

Test No.	Cycle No.	Choke pressure	Verification that the choke operated smoothly and without backdriving within the manufacturers specified torque limit					
			During opening			During closing		
			Yes	No	Witness	Yes	No	Witness
1	1	Atmospheric pressure						
	2	Atmospheric pressure						
	3	Atmospheric pressure						
2	1	Working pressure						
	2	Working pressure						
	3	Working pressure						
	4	Working pressure						
	5	Working pressure						

7.21.3 Subsea choke actuators

7.21.3.1 General

This subclause covers manual and hydraulic actuators for subsea applications. The design of electric power or motor driven actuators, position indicators and control feedback equipment are beyond the scope.

7.21.3.2 Design

7.21.3.2.1 General

a) The design of subsea choke actuators shall comply with 5.1.

b) Design shall consider marine growth, fouling, corrosion, hydraulic operating fluid and, if exposed, the well stream fluid.

c) Subsea choke actuators shall conform to the temperature ratings of 5.1.2.2.

7.21.3.2.2 Manual actuators

a) The design of the manual actuation mechanism shall take into consideration ease of operation, adaptability of diver tools, ADSs and/or ROVs for operations.

b) Manufacturers of manual actuators or overrides for subsea chokes shall document maintenance requirements and operating information such as number of turns to open, nominal operating torque, maximum allowable torque, and where appropriate, linear force to actuate.

c) Rotary operated subsea chokes shall be turned in the counter-clockwise direction to open and the clockwise direction to close as viewed from the end of the stem.

d) Intervention fixtures for manual subsea choke actuators shall comply with a recognized industry standard for ROV.[7)]

[7)] For the purposes of this part of ISO 13628, the industry standard will be replaced by ISO 13628-8 when the latter becomes publicly available.

e) Manufacturer shall document design and operating parameters of subsea choke manual actuators as listed in 7.21.3.2.4

7.21.3.2.3 Hydraulic actuators

a) Hydraulic actuators shall be designed for a nominal hydraulic working pressure rating of either 10,3 MPa (1 500 psi) or 20,7 MPa (3 000 psi) or in accordance with the manufacturer's written specification.

b) Opening and closing force and/or torque of hydraulic actuators shall operate the subsea choke when the choke is at the most severe design operating conditions without exceeding 90 % of the nominal hydraulic operating pressure.

c) Hydraulic actuators shall be designed for a specific choke or specific group of chokes with consideration of the operating characteristics and maximum rated working conditions (temperature range, pressure, depth) of those chokes.

d) Hydraulic actuators shall be designed to operate without damage to the choke or actuator (to the extent that any other performance requirement is not met), when hydraulic actuation pressure (within its design pressure rating) is either applied or vented under any choke bore pressure conditions, or stoppage of the choke bore sealing mechanism at any intermediate position.

e) The design of the hydraulic actuators shall consider the effects of rated working pressure within the choke, external hydrostatic pressure at the manufacturer's maximum depth rating and maximum hydraulic operating pressure.

f) Liquid filled hydraulic actuators shall be designed with volume compensation to accommodate the temperature range specified.

g) Manufacturer shall document design and operating parameters of subsea choke hydraulic actuators as listed in 7.21.3.2.5.

h) Application of operating pressure shall be possible without causing damage even if the manual override has been operated.

7.21.3.2.4 Design and operating parameters of manual actuators for subsea chokes

The following parameters apply:

— operating torque (input);

— maximum rated torque capacity;

— type and size of interface (ROV) for manual operation;

— PSL level;

— material class;

— temperature rating;

— number of turns to operate choke.

7.21.3.2.5 Design and operating parameters of hydraulic actuators for subsea chokes

The following parameters apply:

— design type (ratchet, stepping, rotary, linear actuators);

— maximum output torque capacity;

— PSL level;

— material class;

— temperature rating;

— full stroke definition;

— hydraulic cylinder(s):

  — number of cylinders,

  — volume,

  — pressure rating: maximum hydraulic operating pressure and minimum hydraulic operating pressure;

— type of local position indicator (if any);

— manual override (if supplied):

  — ROV assist or diver assist,

  — maximum input torque capacity,

  — direction to open,

  — hex or socket size and length,

  — number of turns to open or close the choke,

— water depth rating;

— type of volume compensation device (if any).

7.21.3.2.6 Documentation

The actuator manufacturer shall prepare an installation and service manual.

7.21.3.3 Actuator testing

a) Subsea choke actuators shall be factory acceptance tested in accordance with ISO 10423, except for backseating. All test data shall be recorded on a data sheet similar to that indicated in Table 18.

b) When subsea choke actuators are shipped separately, the actuators shall be assembled with a test fixture that meets the specified choke operating parameters, and factory acceptance testing as specified in 7.21.4.2.

7.21.4 Choke and actuator assembly

7.21.4.1 Design

Subsea chokes shall be assembled with an actuator designed to operate that choke.

Subsea choke and actuator assembly designated as "fail in the last position" shall be designed and fabricated to prevent backdriving by the choke at full working pressure, at the loss of hydraulic actuator pressure.

Manual choke actuators shall prevent backdriving under all operating conditions.

Means shall be provided to prevent wellbore fluid from overpressuring the actuator.

Table 18 — FAT data sheet hydraulic actuator

A: Actuator data			
Manufacturer			
Model No.	______	Part No.	______
Serial No.	______	Size	______
Hydraulic pressure rating	______		
Temperature rating	______	PSL level	______
			______
Actuator separate	______ ☐ or with choke ☐		
B: Actuator cylinder seal test (hydrostatic test)			
Test pressure			
Cylinder 1	______		
Holding period	______	Beginning	______
		Completion	______
		Total test time (min)	______
Cylinder 2			
Holding period	______	Beginning	______
		Completion	______
		Total test time (min)	
Performed by	______	Date	______
C: Performance test for actuators shipped separately			
Refer to Table 19.			

7.21.4.2 Choke/actuator assembly factory acceptance test

7.21.4.2.1 General

The subsea choke and actuator assembly shall be tested to demonstrate proper assembly and operation. All test data shall be recorded on a data sheet similar to that indicated in Tables 18 and 19. The test data sheet shall be signed and dated by the person(s) performing the test(s).

7.21.4.2.2 Hydraulic actuator cylinder seal test

The actuator seals shall be pressure-tested in two steps by applying pressures of 20 % and 100 % of the MRWP of the actuator. No visible seal leakage shall be allowed. The minimum test duration for each pressure test shall be 3 min. The test period shall not begin until the test pressure has been reached and has stabilized and the pressure-monitoring device has been isolated from the pressure source. The test pressure reading and time at the beginning and at the end of each pressure-holding period shall be recorded.

Table 19 — FAT data sheet subsea choke

A: Choke data			
Manufacturer			
Model No.	______	Part No.	______
Serial No.	______	Orifice size	______
Working pressure	______	Test pressure	______
Temperature rating	______	PSL level	______

B: Hydrostatic test				
Test pressure				
First holding period	Beginning	______		
	Completion	______		
	Total test time (min)	______		
Second holding period	Beginning	______		
	Completion	______		
	Total test time (min)	______		
Performed by	______		Date	______

C: Operational test of subsea choke with handwheel		
Cycle number	**Pressure in choke** MPa (psi)	**Remarks**
Test 1		
1	0,103 (15)	
2		
3		
Test 2		
1	Working pressure of choke	
2		
3		
4		
5		

Performed by ______ Date ______

7.21.4.2.3 Operational test

Each subsea choke and actuator assembly shall be tested for proper operation in accordance with this part of ISO 13628. This shall be accomplished by actuating the subsea choke from the fully closed position to the fully open position a minimum of three times with the choke body at atmospheric pressure and a minimum of five times with the choke body at rated working pressure.

The operational test of each subsea choke and actuator shall include the recording of the test data given in Table 16 and/or Table 17.

For assemblies with hydraulic operators, the actuation of the choke shall be accomplished with an actuator pressure equal to or less than 90 % of the rated operating pressure, and the following information shall be recorded on a data sheet such as illustrated by Table 19:

— pressure inside choke body;

— actuator pressure required to close choke;

— actuator pressure required to open choke;

— verification that the choke operated smoothly and without backdriving.

For assemblies with manual operators, the following information shall be recorded on a data sheet such as illustrated by Table 17:

— pressure inside choke body;

— verification that the choke operated smoothly and without backdriving within the manufacturer's specified torque limit.

For assemblies with hydraulic operators and manual overrides, both sets of tests outlined above shall be accomplished and the results recorded on a data sheet such as illustrated by Tables 16 and 17.

7.21.5 Materials

Both subsea chokes and subsea actuators shall be made of materials which meet the applicable requirements of 5.2 and the requirements of ISO 10423.

7.21.6 Welding

Welding of pressure-containing components shall be performed in accordance with the requirements given in 5.3. Welding of pressure controlling ("trim") components shall comply with the manufacturer's written specifications.

7.21.7 Marking

Marking shall be as specified in 5.5. In addition, subsea chokes, manual actuators, hydraulic actuators and choke/actuator assemblies shall be marked as given in Table 20, Table 21, Table 22 and Table 23, respectively.

7.22 Miscellaneous equipment

7.22.1 General

A variety of miscellaneous tools and accessories are used with subsea wellhead and subsea completion equipment. This identifies requirements for some common tools. These tools and other miscellaneous equipment not specifically listed here shall be designed and manufactured in accordance with the structural requirements, stress limitations and documentation requirements of 5.1.

Table 20 — Marking data sheet for subsea chokes

Marking	Location
Manufacturer's name and/or trademark	Body or nameplate
Model number and type	Body or nameplate
Maximum working pressure rating	Body or nameplate
Serial or identification number unique to the particular choke	Body or nameplate
Maximum orifice diameter (64th)	
Direction of flow	Body or nameplate
ISO requirements	Body
• ISO 13628-4	
• PSL level	
• Performance level	
• Material class	
• Temperature rating	
• Date (month/year)	Flange(s) periphery
Flange size, pressure and ring joint designation	
Material and hardness	Body and bonnet (cap)
Part number	Body or nameplate

Table 21 — Marking data sheet for manual subsea choke actuators

Marking	Location
Manufacturer	Body or nameplate
Model number	Body or nameplate
Input torque (maximum) capacity	Nameplate
Maximum torque capacity	Nameplate
Number of turns to open	Nameplate
Date (month/year)	Nameplate
Serial number (if required)	Nameplate
Part number	Nameplate
ISO requirements	Nameplate
• PSL level	
• Temperature range	
• ISO 13628-4	
• Date (month/year)	

Table 22 — Marking data sheet for subsea hydraulic choke actuators

Marking	Location
Manufacturer	Nameplate
Model number	Nameplate
Maximum operating hydraulic pressure - MPa (psi)	Nameplate and cylinder
Input torque rating (maximum) - Nm (ft-lbs)	Nameplate
Maximum output torque - Nm (ft-lbs)	Nameplate
Number of steps to open	Nameplate
ISO requirements	Nameplate
• PSL level	
• Temperature range	
• ISO 13628-4	
• Date (month/year)	
Serial number (if required)	Nameplate
Part number	Nameplate
Manual override direction to open	Nameplate

Table 23 — Marking for subsea choke and actuator assembly

Marking	Application
1. Assembler's name or trademark	Nameplate
2. ISO 13628-4	Nameplate
3. Assembly serial or identification number	Nameplate
4. Rated water depth	Nameplate

7.22.2 Design

7.22.2.1 General design requirements

7.22.2.1.1 Loads

As a minimum, the following loads shall, where applicable, be considered when designing miscellaneous equipment:

— suspended weight;

— control pressure;

— well pressure;

— hydrostatic pressure;

— handling loads;

— impact.

7.22.2.1.2 Operating pressure

Tools operated by hydraulic pressure shall be rated in accordance with the pressure ratings specified by the manufacturer.

7.22.2.2 Remote guide line establishment and re-establishment tools

Guide line establishment/re-establishment tools are used to attach cables to guide posts of subsea completion structures. Any such tool which uses the relative guide post positions shall be designed based on the spacing described in 8.3.2.2.

7.22.2.3 Test stands and fixtures

7.22.2.3.1 General

Test stands and fixtures are used at the point of assembly or installation to verify the interface and functional operation and load and pressure capacity of the equipment to be installed. They may also serve as shipping skids for transporting equipment offshore. Test stands and fixtures used only at the manufacturer's facilities are outside the scope of this part of ISO 13628.

7.22.2.3.2 Accuracy of test equipment

Where test equipment is used to simulate a mating component for testing the assembly of interest it shall be made to the same dimensions and tolerances at all interfaces as the simulated component.

7.22.2.3.3 Loads during testing/handling and assembly

Design of test stands and fixtures shall consider assembly and handling loads as well as test loads.

7.22.2.3.4 Tree test stumps

Tree test stumps shall simulate the profiles of the wellhead, tree re-entry spool, etc. to facilitate pressure testing of the tree, tree running tool, cap, etc. They may also contain hydraulic couplers to facilitate testing of the controls functions. Stab pockets may be machined directly in the stump or for tree testing may be contained in a dummy tubing hanger. When specified the tree test stump shall accept a real tubing hanger. Test ports shall communicate with the individual bores of the test stumps to facilitate pressure testing. The benefits of piping all test ports back to a common manifold with isolation test valves shall be examined. A minimum of two dummy guide posts shall be provided to guide equipment on to the test stump.

7.22.2.3.5 Equipment used for shipping

Test skids, etc. used for shipping equipment offshore shall provide protection to the equipment during handling and transportation. Sea fastenings shall be designed to take all the static and accelerated loading conditions due to roll, pitch and heave of the vessel in the locality where it will be transported and should be suitable for securing the assembly to the rig and rig skids.

7.22.3 Materials

Materials shall be selected to meet the requirements of 5.1 and 5.2 if subjected to well fluid contact. Selection of other materials shall consider encountered fluids and galvanic compatibility, as well as mechanical properties.

7.22.4 Testing

All components subject to pressure shall be tested to one and one-half times their maximum rated working pressure unless a different test pressure is required elsewhere in this part of ISO 13628. The test procedure shall conform to 5.4. Fit and functional testing shall be performed in accordance with the manufacturer's written specification for any tool which has an interface with equipment which is to be installed subsea.

7.22.5 Marking

Tools shall be permanently marked following the methods and requirements of 5.5. In addition, all tools which are not a permanent part of a subsea assembly shall be marked with the date of manufacture, applicable load ratings and part number.

8 Specific requirements — Subsea wellhead

8.1 General

This clause describes subsea wellhead systems which are normally run from floating drilling rigs. It establishes standards and specifications for this equipment. Guide lineless systems are not addressed in this part of ISO 13628. The subsea wellhead system supports and seals casing strings. It also supports the BOP stack during drilling, and the subsea tree and possibly the tubing hanger after completion. The subsea wellhead system is installed at or near the mudline.

All pressure-containing and pressure-controlling parts included as part of the subsea wellhead equipment shall be designed to meet all of the requirements of the ANSI/NACE MR0175. These parts include:

— wellhead housing;

— casing hanger bodies;

— annulus seal assemblies.

The following parts or features are excluded from the NACE requirements:

— lock rings;

— load rings;

— load shoulders;

— 406 mm (16 in) suspension equipment;

— bore protectors and wear bushings.

8.2 Temporary guide base

8.2.1 General

The TGB when used provides a guide template for drilling the conductor hole, and stabbing the conductor pipe. It compensates for misalignment from irregular ocean bottom conditions, and provides a support base for the PGB. For guide line systems, it also establishes the initial anchor point for the guide lines. It may also include a provision for suspending a foundation sleeve to support unconsolidated surface soils. The TGB may not always be used, as in the case of template completions or satellite structure (foundation and/or protective structure) completions.

8.2.2 Design

8.2.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the TGB:

— ballast;

— guide line tension;

— weight of conductor pipe;

— weight of PGB assembly;

— soil reaction.

The TGB shall be capable of supporting, as a minimum, a static load of 780 kN (175 000 lbf) on the interface with the PGB while the TGB is supported at four locations, equally spaced 90° ± 2° apart and a minimum of 1 575 mm (62 in) from the centre (radial measure).

8.2.2.2 Dimensions

a) The TGB minimum bearing area shall be 7 m^2 (75 sq ft). This area may be augmented with weld-on or bolt-on extensions to compensate for soil strengths and anticipated loads.

b) TGB should pass through a 5 m (16,4 ft) square opening or as specified by the manufacturer.

c) TGB shall provide four guide line anchor points in position to match the guide posts on the PGB.

d) Together with the PGB, the TGB shall allow a minimum angular misalignment of 5° between the conductor pipe and the temporary guide base.

e) TGB shall provide a minimum storage volume of 2 m^3 (75 cu ft) for ballast material.

8.2.3 Testing

Performance verification testing shall conform to 5.1.7.5. No factory acceptance testing is required.

8.3 Permanent guide base

8.3.1 General

The PGB provides entry into the well prior to BOP installation and, along with the four guide posts, gives guidance for running the subsea BOP stack or the subsea tree. It may establish structural support and final alignment for the wellhead system, and provides a seat and lock down for the conductor housing. PGBs can be built as a single piece or split into two pieces to ease handling and installation. Optionally, they may include provisions for retrieval and to react flowline loads. The PGB may be retrieved after drilling is complete and replaced by a PGB carrying flowline connection/manifold equipment. Alternatively the PGB installed for drilling may carry flowline connection/manifold equipment. In either case equipment must not interfere with BOP stack installation. Consideration shall be given to required ROV access and cuttings disposal.

8.3.2 Design

8.3.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the PGB (see Figures 11 and 12):

— conductor pipe weight;

— conductor housing weight;

— jetting string weight when supported on the spider beams;

— guide line tension (see Figures 11 and 12);

— flowline pull-in, connection, or installation loads (see Figures 11 and 12);

— environmental;

— reaction for TGB;

— installation loads (including conductor hang off on spider beams);

— snagging loads.

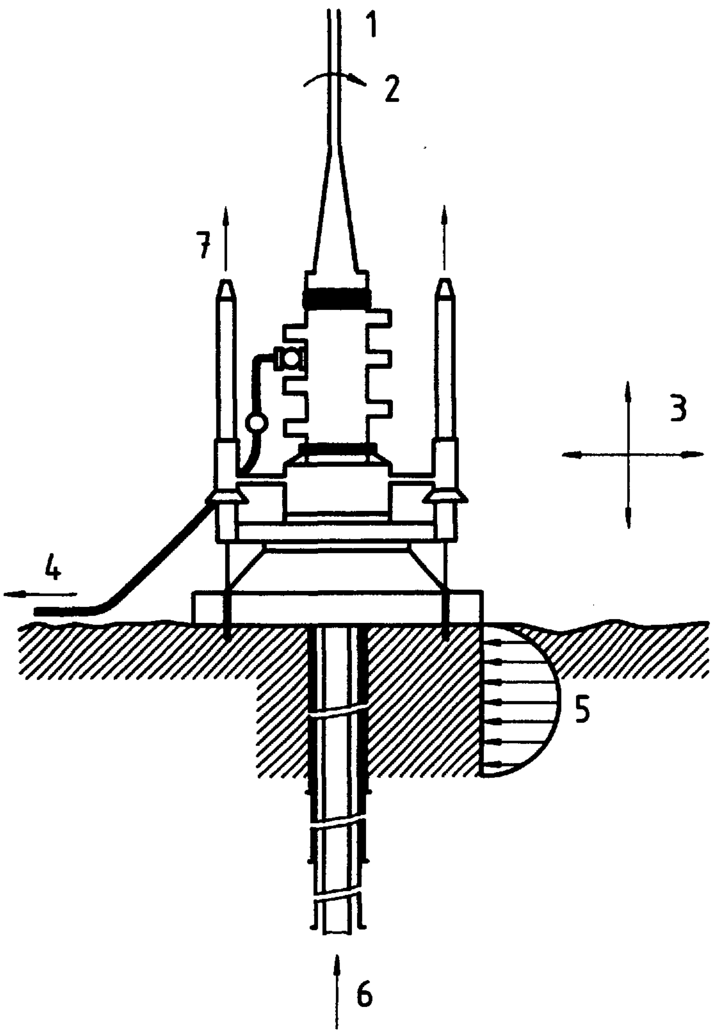
The PGB shall be capable of supporting, as a minimum, a static load of 780 kN (175 000 lbf) on the interface with the conductor housing while the PGB is supported at four locations equally spaced 90° ± 2° apart and a minimum of 1 575 mm (62 in) from the centre (radial measure).

8.3.2.2 Dimensions

a) The dimensions of the PGB shall conform to the dimensions shown in Figure 9 unless orientation system requires tighter tolerances.

b) The guide posts shall be fabricated of 219 mm (8 5/8 in) OD pipe or tubulars. The bottom of the post may be open to allow sheared out anchors to drop to the seabed if required by the anchor design.

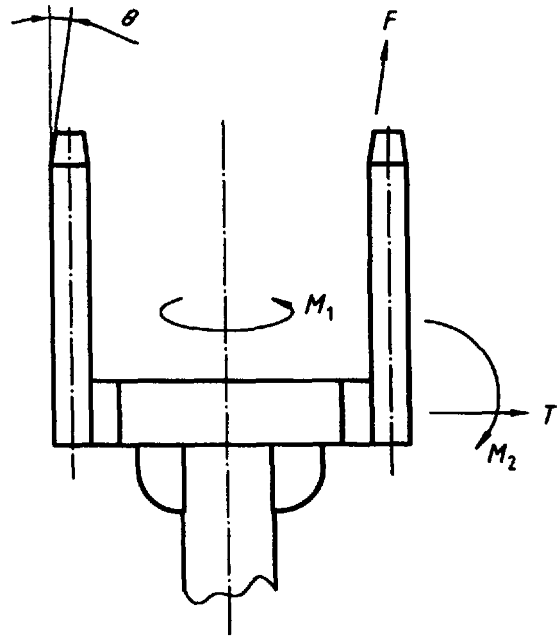
c) The length of the guide post (dimension *H* of Figure 9) shall be 2 500 mm (8 ft) minimum for drilling purposes. The guide posts may be extended to provide guidance for the LRP or tree cap.



Key

1 Riser tension
2 Applied moments
3 Environmental (current, wave, action, etc.)
4 Flowline connection
5 Soil reaction
6 Thermal
7 Guide line tension

Figure 11 — Loads and reactions for a subsea completion



Key

F	Force from guide line
M_1	Torsional bending moment
M_2	Bending moment
T	Tension
θ	Angle at which guide line force acts

Figure 12 — Permanent guide base (PGB) loads

8.3.2.3 Functional requirements

a) When used with the TGB, the PGB shall allow a minimum angular misalignment of 5° between a 762 mm (30 in) nominal conductor pipe and the TGB. For other conductor pipe sizes, the manufacturer shall document the misalignment capability.

b) Guide posts shall be field replaceable without welding, using either diver, ROV or remote tooling. The locking mechanism shall not inadvertently release due to snagging wires, cables, etc.

c) Guide posts can be either slotted or non-slotted. Slotted guide posts are required when used with a TGB, if the guide lines are not to be disconnected from the TGB. For slotted guide posts, provisions shall be made to insert guide lines of at least 19 mm (3/4 in) OD into the post with retainers at the top and at or near the bottom of the post.

d) Provisions shall be made to attach guide lines to the top of the guide posts. These provisions shall be capable of being released and re-established. This may be by the use of diver, ROV or remote tooling.

e) The PGB will contain a feature which facilitates orientation between the PGB and the conductor housing. The orientation device may allow the guide base to be installed in multiple orientation positions to suit rig heading. The orientation device may also provide an anti-rotation feature to resist the loads defined in 8.3.2.1.

f) When specified by the manufacturer, the PGB will contain grouting funnels for cement top-up.

8.3.3 Testing

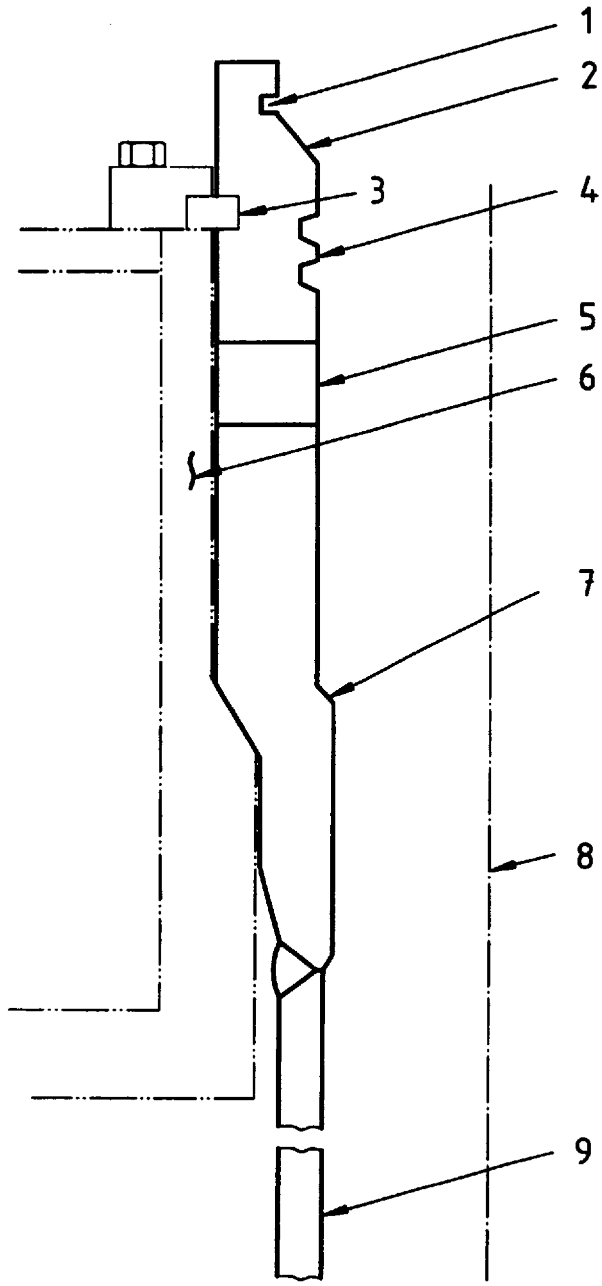
Performance verification testing shall conform to 5.1.7.5. No factory acceptance testing is required.

8.4 Conductor housing

8.4.1 General

The conductor housing attaches to the top of the conductor pipe to form the basic foundation of a subsea well. The housing typically has a means of attaching to the PGB which prevents rotation of the PGB with respect to the housing.

A typical conductor housing profile is shown in Figure 13. The internal profile of the conductor housing includes a landing shoulder suitable for supporting the wellhead housing and the loads imposed during the drilling operation. Running tool preparations should also be a part of the internal housing profile. Cement return passageways may be incorporated in the conductor housing/PGB assembly to allow cement and mud returns to be directed below the PGB.



Key

1 Wellhead lock down
2 Landing shoulder for wellhead
3 PGB attachment
4 Running tool and tieback connector preparation
5 Cement port (optional)
6 PGB
7 Landing shoulder
8 Centreline
9 Conductor casing

Figure 13 — Conductor housing

8.4.2 Design

8.4.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the conductor housing (refer to 8.2.2.1):

— wellhead loads;

— riser forces;

— PGB loads (refer to Figures 11 and 12);

— environmental loads;

— snag loads;

— pressure loads;

— thermal loads.

The interface between the conductor housing and the PGB shall be designed for a rated load of at least 780 kN (175 000 lbf). The conductor housing shall have a minimum rated working pressure of 6,9 MPa (1 000 psi).

8.4.2.2 Dimensions

a) The following dimensions shall apply to 762 mm (30 in) nominal conductor housings:

   — minimum ID 665 mm (26,20 in);

   — maximum OD 950 mm (37,38 in).

b) The conductor housing is not limited to the 762 mm (30 in) size. Rotary table dimensions should be considered when selecting the outside diameter of the conductor housing. The drill bit gauge diameter used for the next string of casing plus 3 mm (1/8 in) clearance should be considered when selecting the internal diameter of the conductor housing.

8.4.2.3 Bottom connection

If the bottom end connection is to be welded, it shall be prepared for a full penetration butt-weld.

8.4.2.4 Pup joint

The conductor housing may have a pup joint which is factory welded on to ease field installation.

8.4.2.5 Handling/support

Handling and support lugs may be supplied for hangoff during installation and for handling during shipping and installation.

8.4.3 Impact testing

Impact testing is not required.

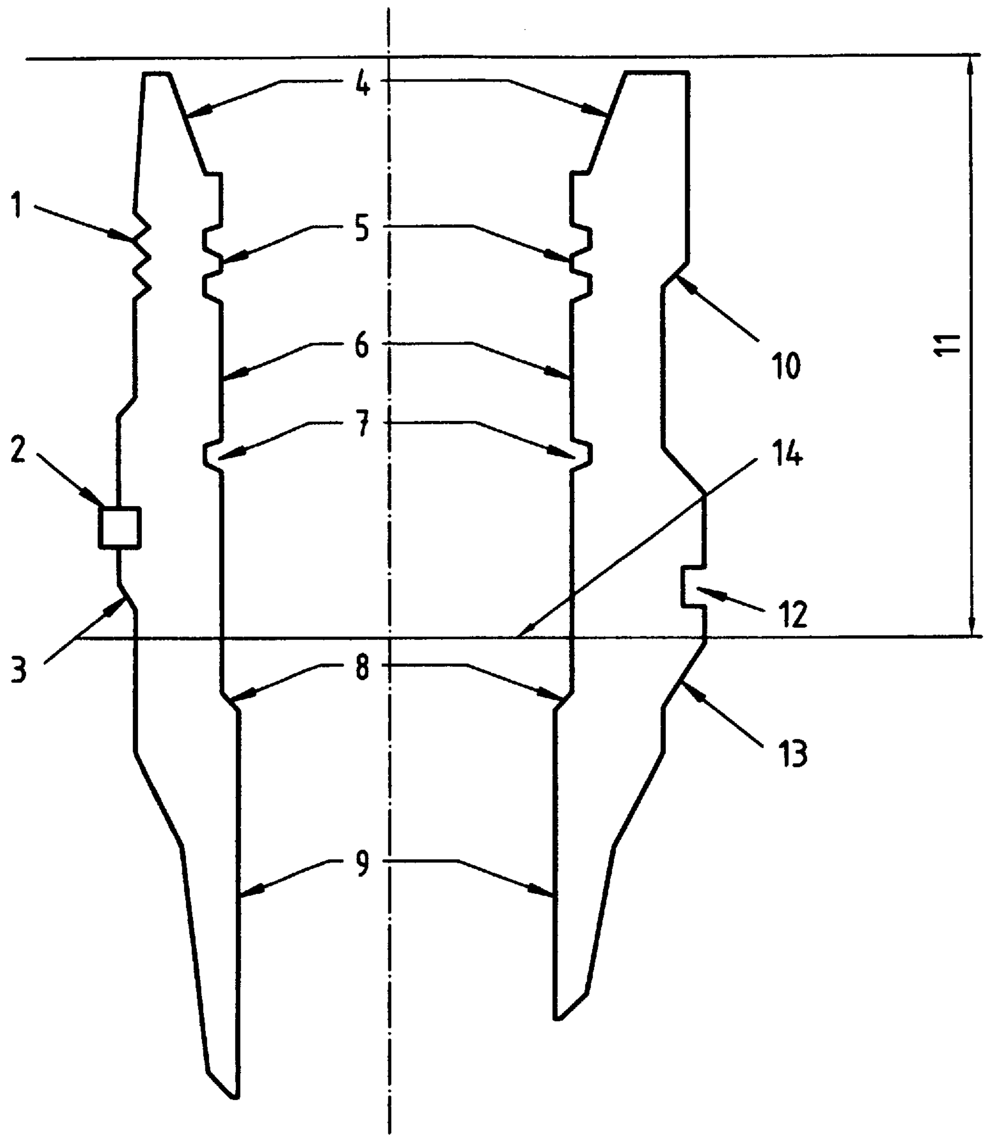
8.4.4 Testing

Performance verification testing shall conform to 5.1.7.5. No factory acceptance testing is required.

8.5 Wellhead housing

8.5.1 General

The wellhead housing lands inside the conductor housing. It provides pressure integrity for the well, suspends the surface and subsequent casing strings and tubing hanger and reacts external loads. The BOP stack or subsea tree attaches to the top of the wellhead housing using a compatible wellhead connector. The wellhead housing shall accept tubing hangers or tubing hanger adapter. The standard system sizes are given in Table 11. Figure 14 shows two profiles of typical wellhead housings.



a) Mandrel type

b) Hub type

Key

1	Connector profile	8	Hanger landing shoulder
2	Housing lock down	9	Min. bore
3	Landing shoulder	10	Connector profile
4	Gasket profile	11	Wellhead housing pressure boundary
5	Running tool preparation	12	Housing lock down
6	Casing hanger/packoff seal area	13	Landing shoulder
7	Hanger lock down profile	14	Position of lowermost casing hanger seal assembly seal element

Figure 14 — Wellhead housings

8.5.2 Design

8.5.2.1 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing the wellhead housing:

— riser forces (drilling, production and workover);

— BOP loads;

— subsea tree loads;

— pressure;

— radial loads;

— thermal loads;

— environmental loads;

— flowline loads;

— suspended casing loads;

— conductor housing reactions;

— tubing hanger reactions;

— hydraulic connector loads.

8.5.2.2 Connections

a) **Top connection**

The top connection should be of a hub or mandrel type (see Figure 14) as specified by the manufacturer. The gasket profiles shall be manufactured from or inlayed with corrosion resistant material as specified in 5.3.3.

b) **Bottom connection**

The high-pressure housing attaches to the top of the surface casing to form the basic foundation of a subsea well. If the bottom connection is to be welded, it shall be prepared for a full penetration butt-weld.

c) **Pup joint**

The wellhead housing may have a pup joint which is factory welded on to ease field installation.

d) **Body penetrations**

Body penetrations within the housing pressure boundary are not permitted.

8.5.3 Dimensions

a) The minimum vertical bore of the wellhead housing shall be as given in Table 11.

b) Dimensions of the wellhead pressure boundary (see Figure 14) shall be in accordance with the manufacturer's written specification.

8.5.4 Rated working pressure

The MRWP for the wellhead housing pressure boundary (see Figure 14) shall be 13,8 MPa (2 000 psi), 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000 psi). Selection of the rated working pressure should consider the maximum expected SCSSV operating pressure (see 5.1.2.1.1).

8.5.5 Testing

8.5.5.1 Factory acceptance testing

All wellhead housings shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic test is performed to verify the pressure integrity of the housing pressure boundary. They shall be tested to the requirements of ISO 10423:1994, clause 605, except that the tests (including PSL 2) shall have a secondary holding period of not less than 15 min.

The hydrostatic body test pressure shall be determined from the housing rated working pressure, see Table 24. The hydrostatic body test pressure shall not be less than the values given in Table 24.

Table 24 — Test pressure

Rated working pressure		Hydrostatic body test pressure	
MPa	(psi)	MPa	(psi)
13,8	(2 000)	27,6	(3 000)
34,5	(5 000)	51,8	(7 500)
69,0	(10 000)	103,5	(15 000)
103,5	(15 000)	155,2	(22 500)

Wellhead housings shall show no visible leakage during each pressure holding period.

8.6 Casing hangers

8.6.1 General

The subsea casing hanger is installed on top of each casing string and supports the string when landed in the wellhead housing. It is configured to run through the drilling riser and subsea BOP stack, land in the subsea wellhead, and support the required casing load. It shall have provisions for an annulus seal assembly, support loads generated by BOP test pressures above the hanger and loads due to subsequent casing strings. Means shall be provided to transfer casing load and test pressure load to the wellhead housing or to the previous casing hanger.

A lockdown mechanism, if required, is used to restrict movement of the casing hanger due to thermal expansion or annulus pressure, it also helps in setting marine casing patches to have the hanger fixed while pulling the casing fish inside the casing patch. An external flowby area allows for returns to flow past the hanger during cementing operations and is designed to minimise pressure drop, while passing as large a particle size as possible. A pup joint of casing should be installed on the hanger in the shop. This reduces the risk of damage during handling.

Subsea casing hangers shall be treated as pressure controlling equipment as defined in ISO 10423. In some cases a casing (typically 16 in) string may be suspended in a landing ring which is included as part of the casing string below the wellhead. The landing ring and hanger shall be treated as mudline suspension equipment as specified in 10.1.1.

8.6.2 Design

8.6.2.1 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing casing hangers:

— suspended weight;

— overpull;

— pressure, internal and external;

— thermal;

— torsional;

— radial;

— impact.

8.6.2.2 Threaded connections

The type of casing threads on the hanger shall be as specified in ISO 10423.

Casing threads shall be coated to prevent galling when required by the thread type or material.

8.6.2.3 Vertical bore

a) **Full opening vertical bore**
The minimum vertical bores for casing hangers shall be as given in Table 25. Equipment conforming to this requirement shall be referred to as having full opening bores.

b) **Reduced opening vertical bore**
Reduced vertical bores may also be supplied.

Table 25 — Minimum vertical bore sizes for casing hangers and wear bushings

Casing OD		Minimum vertical bore	
mm	(in)	mm	(in)
178	(7)	153	(6,03)
194	(7 5/8)	172	(6,78)
219	(8 5/8)	195	(7,66)
244	(9 5/8)	217	(8,53)
273	(10 3/4)	242	(9,53)
298	(11 3/4)	271	(10,66)
340	(13 3/8)	312	(12,28)
406	(16)	376	(14,81)

8.6.2.4 Outside profile

The outside profile shall be in accordance with the manufacturer's written specification.

8.6.2.5 Casing hanger ratings

The load and pressure ratings for casing hangers may be a function of the tubular grade of material and wall section as well as the wellhead equipment in which it is installed. Manufacturers shall determine and document the load/pressure ratings for casing hangers as defined below:

a) **Hanging capacity**

The manufacturer's stated hanging capacity rating for a casing hanger includes the casing thread (normally a female thread) cut into the hanger body.

b) **Pressure rating**

The manufacturer's stated pressure rating for a casing hanger includes the hanger body and the casing thread (normally a female thread) cut into the lower end of the hanger.

NOTE The user is responsible for determining the working pressure of a given weight and grade of casing.

c) **BOP test pressure**

The BOP test pressure rating for a casing hanger is the maximum pressure which may be applied to the upper portion of the hanger body, and to the annulus seal assembly. This rating specifically excludes the casing connection at the lower end of the casing hanger.

The BOP test pressure rating for a casing hanger shall be equal to the rated working pressure of the wellhead housing that the hanger is installed in or as given in Table 26.

d) **Support capacity**

The manufacturer's stated support capacity is the rated weight which the casing hanger(s) are capable of transferring to the wellhead housing or previous casing hanger(s). The effects of full rated internal working pressure shall be included.

Table 26 — Minimum rated pressure for BOP testing

Casing hanger size	BOP test pressure rating
476 mm x 406 mm (18 3/4 in x 16 in)	20,7 MPa (3 000 psi)
476 mm x 340 mm (18 3/4 in x 13 3/8 in)	69,0 MPa (10 000 psi)

8.6.2.6 Flowby area

Casing hanger minimum flowby areas and maximum particle size shall be documented by the manufacturer and maintained for each casing hanger assembly.

8.6.3 Testing

8.6.3.1 Performance verification testing

Performance verification testing of subsea wellhead casing hangers shall conform to 5.1.7. Performance verification testing for internal pressure shall be performed to verify the structural integrity of the hanger and shall be independent of the casing grade and thread.

8.6.3.2 Factory acceptance testing

Factory acceptance testing of subsea wellhead casing hangers need not include a hydrostatic test. A dimensional check or drift test shall be performed on the hanger to verify the minimum vertical bore (refer to Table 25).

8.7 Annulus seal assemblies

8.7.1 General

Annulus seal assemblies provide pressure isolation between each casing hanger and the wellhead housing. They may be run simultaneously with the subsea casing hanger, or separately. Annulus seal assemblies are actuated by various methods, including torque, weight and/or hydraulic pressure.

Subsea annulus seal assemblies shall be treated as pressure controlling equipment as defined in ISO 10423.

8.7.2 Design

8.7.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the annulus seal assemblies:

— setting loads;

— thermal loads;

— pressure loads;

— releasing and/or retrieval loads.

8.7.2.2 Rated working pressure

The annulus seal assembly shall contain pressure from above equal to the rated working pressure of the casing hanger [see 8.6.2.5 b)].

8.7.2.3 Outside profile

The outside profile shall be in accordance with the manufacturer's written specification.

8.7.2.4 Lockdown

The annulus seal assembly may be locked to the casing hanger and/or wellhead using a lock mechanism that allows retrieval without damage to the seal surfaces in the event of seal failure.

8.7.2.5 Emergency annulus seal assemblies

Emergency annulus seal assemblies which position the seal in a different area or use a different seal mechanism may be supplied. They shall meet all requirements given in 8.7.2.

8.7.3 Factory acceptance testing

Factory acceptance testing is not required.

8.8 Bore protectors and wear bushings

8.8.1 General

A bore protector protects annulus seal assembly sealing surfaces inside the wellhead housing before casing hangers are installed. After a casing hanger is run, a corresponding size wear bushing is installed to protect the remaining annular sealing surfaces and the previously installed annular seal assemblies and casing hangers. They are generally not pressure retaining devices. However, wear bushings may be designed for BOP stack pressure test loading.

8.8.2 Design

8.8.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the bore protectors or wear bushings:

— BOP test pressure loading;

- radial loads;

- drill pipe hang off loads.

Bore protectors or wear bushings do not need to meet the requirements of clause 5.

8.8.2.2 Vertical bores

a) **Full opening vertical bores**

The minimum vertical bore of the bore protector shall be as given in Table 27. The minimum vertical bore through wear bushings shall be as given in Table 25. Bore protectors and wear bushings conforming to these requirements shall be referred to as having full opening bores.

b) **Reduced opening vertical bores**

Reduced vertical bores may also be supplied.

Table 27 — Minimum vertical bores for bore protectors

Nominal BOP stack sizes mm (in)	Minimum vertical bore mm (in)
346 (13 5/8)	312 (12,31)
425 (16 3/4)	384 (15,12)
476 (18 3/4)	446 (17,56)
527 to 540 (20 3/4 to 21 1/4)	472 (18,59)

8.8.2.3 Outside profile

The outside profile shall be in accordance with the manufacturer's written specifications.

8.8.2.4 Rated working pressure

Bore protectors and wear bushings are not normally designed to retain pressure.

8.8.2.5 Lockdown/anti-rotation

Means shall be provided to restrain or lock the wear bushings or bore protector within the housing. This feature may also be designed to minimize rotation.

8.8.3 Materials

The materials used in bore protectors and wear bushings shall comply with the manufacturer's written specifications.

8.8.4 Testing

Bore protectors and wear bushing shall be dimensionally inspected to confirm minimum vertical bore.

8.9 Corrosion cap

The function of the corrosion cap is to protect the subsea wellhead from contamination by debris, marine growth and corrosion. These caps usually are non-pressure-containing and lock onto the external profile of the wellhead housing. If a pressure retaining cap is utilised, means shall be provided for sensing and relieving pressure prior to releasing the cap. The cap is installed just prior to temporary abandonment of a well. It may be a design which allows installation prior to, or after installation of, the tubing hanger. The cap may be required to have the facility for injection of a corrosion inhibitor into the well.

8.10 Running, retrieving and testing tools

Tools for running, retrieving and for testing all subsea wellhead components including guidance equipment, housings, casing suspension equipment, annulus sealing equipment and protective devices are addressed in annex H.

9 Specific requirements — Subsea tubing hanger system

9.1 General

The tubing hanger system is comprised of a tubing suspension device called a tubing hanger and an associated tubing hanger running tool and in certain cases an orientation joint. This part of ISO 13628 is limited to tubing hangers which are landed in a wellhead, tubing spool or horizontal tree. A tubing annulus seal is effected between the tubing hanger and casing hanger or tubing hanger and spool, and the hanger is locked in place. It is designed to provide a means for making a pressure-tight connection between the tubing string(s), tubing annulus and the corresponding subsea tree or tubing hanger running tool bores. It may also provide a continuous means of communication or control SCSSVs, electrical transducers and/or other devices. There are three basic types of tubing hangers:

a) concentric;

b) eccentric (those that require orientation to align multiple tubing bores or control ports);

c) horizontal tree type (having the production bore branching off at right angles from the tubing hanger bore).

There are two types of orientation systems:

— active (rotary) type, requiring the running string to be rotated by application of torque at surface, until it locates an orientation device which orients the hanger relative to the PGB posts;

— passive (linear) type, uses downward or upward motion of the running string to engage a pin or key in an orientation device which automatically orients the hanger relative to the PGB posts.

9.2 Design

9.2.1 General

The OD of the tubing hanger system shall be compatible with the ID of the BOP stack and marine riser system being used. Particular attention shall be given to the design of the lock and seal mechanisms to minimise the risk of them hanging up during installation or retrieval. The design shall keep diameters to the minimum and minimise the length of large diameters in order to ease running and retrieving of the tubing hanger system through the ball/flex joint. The operating procedures should advise the limiting ball/flex joint angle for running and retrieving of the tubing hanger system. The design of tubing hanger systems shall comply with 5.1. Ideally irrespective of orientation system, the seals shall not engage in the sealing bore until the orientation is complete. Typical orientation devices are, keys engaging in slots in the BOP connector, orienting bushings/cams temporarily installed in the BOP connector, orienting bushings/cams permanently installed in the tubing head spool or horizontal tree and extending pins in the BOP stack used in conjunction with a camming profile on the running tool or orientation joint.

For purposes the orientation joint when supplied will be classed as part of the tubing hanger running tool and shall meet the requirements of the tubing hanger running tool.

On concentric tubing hanger systems and horizontal trees, annulus access may be through an outlet below the tubing hanger in the tubing spool or horizontal tree body. Where it is through the hanger and into the tree connector cavity area, then provision shall be provided for sealing off the annulus bore, by the use of a check valve, sliding sleeve or similar device.

The tubing hanger running tool may be mechanically or hydraulically actuated. On hydraulically actuated designs the running tool shall be of a "fail as is" design, so that in the event of loss of control pressure, it shall not result in the release of the tubing hanger from its running tool. There shall be positive indication that the running tool is correctly attached to the tubing hanger before supporting the weight of the tubing string. It is a requirement to effect release of the hydraulic running tool from the tubing hanger in the event of lost hydraulic control pressure. The top of the running tool/orientation joint shall interface with the completion riser, tubing strings or drill pipe as specified by the manufacturer. On horizontal tree applications the top of the running tool/extension joint shall interface with the tieback string or subsea test tree.

9.2.2 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing the tubing hanger system:

— suspended weight;

— overpull;

— pressure, internal and external;

— tubing hanger/running tool separation loads due to pressure testing;

— thermal loads;

— torsional loads;

— radial loads;

— oriented loads;

— tree reacting loads.

9.2.3 Threaded connections

9.2.3.1 Tubing hanger

The type of tubing threads on the hanger shall conform to ISO 10423. Tubing threads shall be coated to prevent galling when required by the thread type or material.

9.2.3.2 Running tool

Tubing threads or tool joints, if used, shall be in conformance with ISO 10422 or ISO 10424 or, the manufacturer's written specification. The tool shall have adequate dimension for tonging.

The load capacity of the tool shall not be inferred from the choice of end connections on the tools.

9.2.4 Running tool seals

All stab subs and other sealing elements shall have a minimum of two elastomer seals.

9.2.5 Vertical bores

The minimum vertical bore with and without profiles shall comply with the manufacturer's written specification. The effect of wall thickness reduction due to plug profiles in the tubing hanger shall be included in the design analysis and documented as required in 5.1. The plug latching profile may be machined in an insert or may be machined directly into the tubing hanger. When an insert is used the plug shall seal directly to the hanger body, not into the insert, unless the insert is of a welded in design. The tubing hanger bores shall be drifted in accordance with manufacturer's written specifications. When specified by the manufacturer the annulus bore shall include a plug catcher device which may be integral or threaded to the hanger. When specified by the user, the plug profiles shall be in nipples threaded into the bottom of the hanger.

On horizontal trees consideration will be given to protection of the plug profiles during down hole wireline or coiled tubing interventions.

9.2.6 Rated working pressure

The rated working pressure of the tubing hanger shall equal or exceed the maximum pressure which may be applied to the hanger body, tubing hanger lockdown, tubing hanger annulus seal and the operating control pressure of the SCSSV, unless relief is provided as described in 5.1.2.1.1. This rating shall be exclusive of the tubing connection(s) at the bottom of the hanger. The tubing hanger shall have a rated working pressure of either 34,5 MPa (5 000 psi), 51,7 MPa (7 500 psi), 69,0 MPa (10 000 psi), 86,3 MPa (12 500 psi), 103,5 MPa (15 000 psi) or 120,7 MPa (17 500 psi) .

NOTE This pressure rating requirement allows for possible leakage of pressure from the SCSSV control line into the annulus cavity above or below the tubing hanger.

9.2.7 SCSSV control line stab design

SCSSV control line stabs in the tubing hanger shall be designed so as to vent control pressure when the tree is removed. The SCSSV control stab shall be designed to minimize the ingress of debris and seawater when the tree is removed. The pressure rating of the control line stabs shazll be the same or greater than the SCSSV control pressure and shall be selected from 9.2.6.

9.2.8 Miscellaneous tools

Miscellaneous tools such as storage and test stands, emergency recovery tools, inspection stands, lead impression tools, wireline installed internal isolation sleeve (horizontal tree) shall be supplied as needed.

9.3 Materials

Materials used for tubing hanger systems shall comply with 5.2. All metal-to-metal sealing surfaces in the production (injection) and annulus bores shall be either manufactured from, or inlayed with, corrosion-resistant materials, with the exception of threads at the bottom of the tubing hanger.

9.4 Testing

9.4.1 Performance verification testing

Performance verification testing of the tubing hanger shall comply with 5.1.7. In addition, the tubing hanger lockdown shall be tested to a minimum of 1,1 times the MRWP from below. Where annulus access devices (e.g. poppet, shuttle, sliding sleeve, etc.) are incorporated into the tubing hanger design, these shall, as far as is practicable, be treated as for gate valves with respect to design performance qualification requirements. (Refer to Table 3).

9.4.2 Factory acceptance testing

9.4.2.1 Tubing hanger

All tubing hangers shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic body test pressure shall be equal or greater than the rated working pressure.

Tubing hangers shall be tested to the requirements of 5.4 except that they shall have a secondary holding period of a minimum of 15 min. In addition, the through bores (excluding tubing threads) of the tubing hanger shall be tested to at least 1,5 times the MRWP.

A pup joint of tubing shall be installed on the hanger and the connection hydrostatic tested to manufacturer's written specifications.

Tubing hanger internal profiles shall be drifted and pressure tested with mating plug to the manufacturer's written specifications.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, locking mechanisms, instrumentation and control line. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

9.4.2.2 Tubing hanger running tool

All wellbore pressure-containing/controlling components shall comply with the hydrostatic test requirements of 5.4 with the exception that the through bores of the running tools shall be tested to a test pressure equal to at least 1,5 times the rated working pressure.

Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test in accordance with the requirements given in 7.9.4.2.2.

Functional testing shall be conducted in accordance with the manufacturer's written specification to verify the primary and secondary operating and release mechanisms, override mechanisms, locking mechanisms, instrumentation and control line. Testing shall verify that actual operating forces/pressures fall within the manufacturer's documented specifications.

10 Specific requirements — Conventional mudline suspension equipment

10.1 General

10.1.1 Introduction

This subclause covers drilling and completion equipment used to suspend casing weight at or near the mudline, to provide pressure control and to provide annulus access to the surface wellhead. Mudline equipment is used when drilling with a bottom supported rig or platform and provides for drilling, abandonment, platform and subsea tieback. Mudline landing rings and hangers may sometimes be used as part of the casing string below a subsea wellhead. Such parts shall comply with the requirements of this subclause.

Mudline casing hangers, casing hanger running tools (landing subs), casing hanger landing rings, and tieback tools (tieback subs) are in fact an integral part of the casing strings. They are therefore specifically excluded from the design requirements and pressure rating methods assigned to like components in ISO 10423 and clause 8 of this part of ISO 13628, and specifically given the design requirements and stress allowable in 10.1 through 10.5. These stress allowable are in keeping with current industry practice for safe working pressures for casing.

Mudline equipment typically involves proprietary profiles/configurations and/or ISO standard connections. The tools used for installation, retrieval and testing are typically task specific and remotely operated.

The technical content of this subclause provides equipment specific requirements for performance, design, material and testing. Specific mudline suspension equipment used during drilling and/or run as part of the casing string includes (see Figure E.1):

— landing rings;

— casing hangers;

— casing hanger running tools (landing subs);

— tieback tools (tieback subs);

— abandonment caps.

Mudline suspension equipment used during drilling and/or run as part of the casing string is designated pressure controlling equipment as defined in ISO 10423. Quality control for these components shall be treated as "casing and tubing hanger mandrels" as set forth in ISO 10423.

Specific mudline conversion equipment for subsea completions includes (see Figure E.1):

— tieback adapters;

— tubing spools.

Mudline conversion equipment shall be designated as either pressure-containing or pressure controlling using the definitions set forth in ISO 10423. Components designated as pressure-containing shall be treated as "bodies" in ISO 10423.

High pressure risers and accessory tools used with mudline equipment, such as brush and cleanout tools, cap running tools, etc., are beyond the scope of this part of ISO 13628.

Guidance systems that interface with a subsea BOP stack shall be designed, fabricated and tested in accordance with 8.3.

10.1.2 Design

The general design requirements for mudline equipment shall comply with 5.1. If specific requirements for mudline equipment in this subclause differ from the general requirements stated in 5.1, these specific requirements shall take precedence.

10.1.2.1 Rated working pressure

For each piece of mudline equipment, a rated working pressure shall be determined according to Table 28 and annex E or by proof testing as specified in ISO 10423.

The rated working pressure shall be inclusive of the pressure capacity of the end connections.

Table 28 — Maximum allowable stress due to pressure (for mudline equipment only)

Rated working pressure suspension equipment	Conversion equipment	Test pressure suspension and conversion
Membrane stress = S_m (where $S_m + S_b \leqslant 1{,}0$)		
0,8 S_y	0,67 S_y	0,9 S_y
Membrane + Bending = $S_m + S_h$ (where $S_m \leqslant$ 0,67 Yield)		
1,2 S_y	1,0 S_y	1,35 S_y
(where $S_m \geqslant$ 0,67 Yield or $\leqslant$ 0,9 Yield)		
2,004 S_y – 1,2 S_m	NA	2,15 S_y – 1,2 S_y

NOTE 1 Stresses given in this Table shall be determined in accordance with the definitions and methods presented in annex E. The designer shall consider the effects of stresses beyond the yield point on non-integral connections such as threaded connections and latch profiles, where progressive distortion can result.

NOTE 2 Bending stresses in this method are limited to lower values than are permitted by the ASME method for secondary stresses since this is a limit-based method with inherently higher safety margins. An alternative method is included in annex E to permit higher secondary stresses while controlling membrane stresses to traditional, more conservative limits.

10.1.2.2 Hanging/running capacity rating

10.1.2.2.1 Rating running capacity

A rated running capacity shall be determined for each piece of mudline suspension equipment in the load path between the top connection of the running tool and the lower connection of the hanger that is run as part of the *casing string. The rated running* capacity is defined as the maximum weight that can be run below the mudline component. Rated running capacity is not the same as joint strength, ultimate tensile strength or proof test load.

Rated running capacity includes the tension capacity of the threaded end connection that is machined into the mudline component and excludes thread pullout strength for the threaded end connection since pullout strength is a function of the weight and grade of casing that is threaded into the mudline component during use.

Primary membrane stresses in the body at the rated running capacity shall not exceed 80 % of the minimum specified yield strength and shall be exclusive of internally applied pressure and externally applied global bending loads.

10.1.2.2.2 Rated hanging capacity

The rated hanging capacities shall be determined for each piece of mudline suspension equipment that hangs casing weight. The rated hanging capacity is defined as the maximum weight that can be suspended from the component at the rated location.

NOTE Different rated hanging capacities may be required for several locations on the component. For example, each external expanding latch or fixed landing ring and each internal latch profile or internal landing shoulder(s) shall have a rated hanging capacity.

Compressive stresses at load shoulders shall be permitted to exceed material yield strength at the rated hanging capacity provided that all other performance requirements are satisfied.

Rated hanging capacities shall include the effects of full rated working pressure. Both internal and external pressure shall be included. Primary membrane stresses in the body at the rated hanging capacities shall not exceed 80 % of minimum specified yield strength.

Rated hanging capacities shall be documented by the manufacturer for a given set of nested equipment in an assembly or for each component individually.

10.1.2.3 Outside and inside diameters

All mudline equipment minimum bores and ODs will be minimum and maximum machining dimensions, respectively, and shall be stated in decimal form to the nearest 0,02 mm (0,001 in). This requirement applies only to components which will pass through, or will have passed through them, other mudline components, tubulars or bits, etc. Outside dimensions shall exclude the expanded condition of expanding latches. These dimensions shall be documented by the manufacturer.

10.1.2.4 Flowby areas

Manufacturers shall document the minimum flowby area and maximum particle size provided for each design, including:

— flowby area while running through a specified weight of casing;

— flowby area when landed in a specified mudline component.

10.1.2.5 Temperature ratings

Each component shall have a temperature rating as specified in 5.1.2.2.

10.1.3 Materials

10.1.3.1 Material classes

Appropriate material classes for mudline equipment are AA or CC for general service, and DD or FF for sour service as defined by NACE and 5.1.2.3.2.

10.1.3.2 NACE requirements

For material classes DD and FF (sour service), ANSI/NACE MR0175 requirements shall be limited to the internal pressure-containing and pressure controlling components, exposed to wellbore fluids. For example, sour service mudline hangers may include non-NACE external latch mechanisms and load rings.

10.1.4 Testing

10.1.4.1 Performance verification testing

Manufacturers are required to conduct and document performance verification testing results in accordance with 5.1.

10.1.4.2 Factory acceptance testing

10.1.4.2.1 Hydrostatic testing

Hydrostatic factory acceptance testing of mudline suspension equipment is not a requirement. If included in the manufacturer's written specification, then test pressures shall not exceed the test pressure as determined in E.2.5.

Hydrostatic factory acceptance testing of mudline conversion equipment is mandatory and shall be tested in accordance with 5.4.5.

10.1.4.2.2 Drift testing

Drift testing is not a requirement of this part of ISO 13628. If drift testing is included in the manufacturer's written specification, then the requirements in ISO 11960:1996, clause 7, shall be followed. The drift test may specify either individual component drift testing or assembly drift testing (i.e. hanger, running tool and casing pups assembled together).

10.1.4.2.3 Stack-up and fit test

Stack-up and fit test is not required by this part of ISO 13628. If stack-up and fit test is part of the manufacturer's written specification, then the manufacturer shall document the requirements for measuring and/or recording axial and drift dimensions to be taken to verify proper stack-up.

10.1.5 Marking and documentation

All mudline equipment shall be stamped with at least the following information:

— manufacture name or trademark;

— nominal size;

— assembly serial number (if applicable);

— part number and revision;

— material class.

The following information shall be either stamped on the equipment or provided in system documentation as applicable:

— rated working pressure;

— rated running capacity;

— rated hanging capacity;

— minimum flowby area;

— maximum particle size;

— drift diameter;

— maximum allowable test pressure.

In addition to the above requirements, mudline conversion equipment shall be stamped in accordance with 5.5.

10.2 Mudline suspension-landing/elevation ring

10.2.1 Description

The landing/elevation ring is an internal upset located at or near the mudline to provide an internal landing shoulder for supporting all combined casing loads. The following considerations shall be addressed when generating designs and technical specifications for the landing elevation ring:

— shoulder load bearing strength;

— completion elevation above mudline;

— centralization of casing hangers;

— mud and cement return flowby area.

10.2.2 Design

The following criteria shall be considered and documented by the manufacturer when designing the landing/elevation ring:

— structural loads (including casing hanging loads);

— dimensional compatibility with other hangers;

— dimensional compatibility with specified bit programme;

— welding requirements;

— mud flowby requirements.

The minimum ID of each ring shall be selected to allow both the landing of subsequent casing hangers and the passage of bit sizes to be used.

10.2.3 Documentation

The manufacturer shall document any critical alignment and/or welding requirements for attachment of the landing/elevation ring to the conductor pipe.

10.3 Casing hangers

10.3.1 Description

10.3.1.1 Mudline casing hangers

These typically provide the following functions and features within the mudline suspension system:

— support casing weight at mudline;

— support casing weight of subsequent strings;

— allow annulus access to the surface wellhead;

— allow for mud/cement flowby while running and landing in previous hanger;

— allow attachment of running tool, tieback riser sub and/or subsea conversion equipment;

— provide for reciprocating the casing string during cementing operations.

10.3.1.2 End connections

The casing hanger and running tool are normally installed with casing extensions made up to both ends. Normally the running tool (landing sub) extension will have a pin-by-box casing nipple extension, and the casing hanger will have a pin-by-pin casing extension. The assembly of casing extensions, running tool and casing hanger shall be done prior to shipment to the rig. This allows the casing hanger assembly to be handled and run just as another piece of casing.

10.3.1.3 Landing shoulders

Landing shoulders on casing hangers are typically one of two following types:

— fixed support rings;

— nonfixed or expanding/contracting latch rings.

The fixed support ring lands on a bevelled landing shoulder (usually 45°) in the landing ring or previous casing hanger. Flowby porting for mud and cement passage and adequate bearing capacity is maintained on this landing ring.

The nonfixed support ring has an expanding/contracting latching load ring which locates in the appropriate landing groove. In some cases during cementing operations, the casing is reciprocated a short distance above the hanger seat. Therefore, the nonfixed landing rings typically do not have permanent lockdown mechanisms.

10.3.1.4 Internal profiles

The internal profiles of mudline casing hangers serve these functions:

— lock and seal running tool (landing sub) and tieback adapters;

— seat subsequent casing hangers;

— seat tubing hanger (optional).

The lock and seal mechanism for the running tool and tieback adapters is usually the upper internal profile of the mudline casing hanger. The locking profile may be a thread or an internal locking groove for a cam-actuated locking mechanism. The running tool is usually designed to release with right-hand rotation.

Wash ports may be incorporated as necessary into each landing sub or casing hanger to give a washout flow rate, without cutting out the port area. After the casing hanger has been landed and cemented, the wash ports are opened. After flushing out the casing riser annulus, the wash ports are closed. The purpose of washing out the casing riser area is to ensure that excessive cement has been removed from the casing hanger/running tool connection area.

10.3.2 Design

10.3.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing mudline system casing hangers:

— casing loads;

— pressure;

— operating torque.

10.3.2.2 Flowby area

Casing hanger minimum flowby areas shall be documented by the manufacturer for each casing hanger design configuration.

10.3.2.3 Particle size

Maximum particle size shall be documented for each casing hanger design configuration.

10.3.2.4 End connections

Standard ISO or other end connections provided on the casing hanger and running tool (landing sub) shall comply with the requirements of 7.1 through 7.6.

Adequate surface areas for tongs should be provided for installing casing into the casing hanger and running tool (landing sub).

10.4 Casing hanger running and tieback tools

10.4.1 Description

Casing hanger running tools shall be designed to provide a reversible connection between the mudline hanger and the casing riser used for drilling operations. They may be either threaded (including optional weight set) or cam-actuated tools as supplied by each individual manufacturer. Threaded running tools engage directly into the casing hanger. Cam-actuated tools engage in an internal locking groove inside of the casing hanger. Wash ports may be provided in the casing hanger or landing sub to allow for cleaning of cement from around the previously run hanger/landing sub connection.

Casing hanger tieback tools (tieback subs) are used to connect tieback adaptors to mudline suspension wellhead equipment for subsea completion purposes. The requirements for tieback tools shall be the same as those for casing hanger running tools.

10.4.2 Design

10.4.2.1 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing the running tools:

— suspended weight;

— pressure loads;

— torque;

— overpull;

— environmental loads.

10.4.2.2 Threaded running and tieback tools

Threaded running tools shall be right-hand release. Threaded tieback tools and tieback profiles shall be right-hand make-up.

10.5 Abandonment caps

10.5.1 Description

Abandonment caps typically are used during temporary abandonment and protect internal hanger profiles, threads and seal areas from marine growth, mechanical damage and debris.

10.5.2 Design

Pressure and any external loads applied during installation, pressure relief and retrieval shall be considered and documented by the manufacturer in the design of abandonment caps. Abandonment caps shall be equipped with a means of relieving pressure prior to removal.

10.6 Tieback adapters — Mudline conversion equipment for subsea completions

10.6.1 Description

Tieback adapters provide the interface between mudline suspension equipment and subsea completion equipment (see Figure E.1). Care shall be exercised when specifying *in situ* testing of conversion equipment that the suspension equipment does not see higher pressure than it is rated for.

10.6.2 Design

Tieback adapters typically provide structural support and pressure control for preparing a well drilled with mudline hangers for a subsea completion.

One or more seals shall be provided between production casing tieback adapter and the tubing hanger spool.

Tieback adapters shall provide structural integrity to transfer applied loads to the surface casing or conductor pipe.

10.7 Tubing hanger spools — Mudline conversion equipment for subsea completions

The tubing hanger spool is attached to a tieback adapter on the lower end and to the tree on the upper end. The spool houses the tubing hanger/wear bushing and may provide an annulus access connection. Care shall be exercised when specifying *in situ* testing of tubing hanger spools that the suspension equipment does not see higher pressures than it is rated for.

10.8 Tubing hanger system — Mudline conversion equipment for subsea completions

All design, materials and testing of the tubing hanger system shall be in accordance with clause 9.

11 Scope specific requirements — Drill-through mudline suspension equipment

11.1 General

This clause describes drill-through mudline suspension equipment which is normally run from a bottom-supported drilling rig. Drill-through mudline suspension equipment is used when it is anticipated that the well will be completed using subsea completion technology. As with subsea wellhead, a wellhead housing is used to accommodate the casing hanger(s), annulus seal assembly(s) and tubing hanger when installed, therefore no conversion equipment is required for subsea completion. The wellhead housing is typically a 346 mm (13 5/8 in) nominal size. During the drilling phase each casing string is connected back to the surface by a riser or casing tieback string. The risers and casing strings are outwit the scope of this part of ISO 13628. Temporary abandonment caps are used to contain the well pressure during the phase between drilling and completion. Figure F.1 illustrates a typical drill-through mudline suspension arrangement. A typical casing programme which the drill-through mudline system has to suspend is:

— 762 mm (30 in) conductor;

— 508 mm (20 in) or 473 mm (18 5/8 in) surface casing;

— 340 mm (13 3/8 in) intermediate casing;

— 273 mm (10 3/4 in) or 244 mm (9 5/8 in) production casing.

All pressure-containing and pressure-controlling parts included as part of the drill-through mudline suspension equipment shall be designed to meet all of the requirements of the ANSI/NACE MR0175. These parts include:

— 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger (may be non-NACE depending on surface casing design);

— wellhead housing;

— casing hanger bodies;

— annulus seal assemblies;

— pressure-containing temporary abandonment cap.

The following parts or features are excluded from the NACE requirements:

— lock rings;

— load rings;

— load shoulders;

— bore protectors and wear bushings.

Guidance equipment serves the same purpose as that used with subsea wellhead, therefore it shall be designed, fabricated and tested in accordance with 8.3.

11.2 Conductor housing

11.2.1 General

The conductor housing attaches to the top of the conductor pipe and provides a tieback point when required for an environmental pipe back to surface. The environmental pipe is normally the same as the conductor pipe. Externally the conductor housing has a preparation for attachment and orientation of the guide base which may be run with the conductor housing or may be installed prior to completion. Internally it has a landing shoulder for the surface casing hanger. This landing shoulder shall support the surface casing hanger, the wellhead housing, the internal casing strings and the loads transferred from the risers during drilling.

11.2.2 Design

When generating the design and technical specification for the conductor housing the following shall be considered:

— completion elevation above the mudline;

— centralization of surface casing hanger;

— mud and cement return flow by area;

— dimensional compatibility with surface casing hanger;

— dimensional compatibility with specified bit programme.

11.2.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the conductor housing:

— surface casing, wellhead, casing and tubing loads;

— riser or/and casing tieback loads;

— PGB loads (refer to Figures 11 and 12);

— environmental loads;

— pressure loads;

— thermal loads.

The interface between the conductor housing and the PGB shall be designed for a rated load of at least) 780 kN (175 000 lbf). The conductor housing shall have a minimum rated working pressure of 6,9 MPa (1 000 psi).

11.2.2.2 Dimensions

a) The following dimensions shall apply to 762 mm (30 in) nominal conductor housings:

minimum ID	665 mm (26,2 in)
maximum OD	950 mm (37,38 in)

b) The conductor housing is not limited to the 762 mm (30 in) size. Rotary table dimensions should be considered when selecting the OD of the conductor housing. The drill bit gauge diameter used for the next string of casing plus 3 mm (1/8 in) clearance should be considered when selecting the internal diameter of the conductor housing.

11.2.2.3 Top connection

The top connection may be prepared for a full penetration butt weld profile or have a thread or latching profile for a running/tie-back tool.

11.2.2.4 Bottom end connection

If the bottom end connection is to be welded, it shall be prepared for a full penetration butt-weld.

11.2.2.5 Pup joint

The conductor housing may have a pup joint which is factory welded on to ease field installation.

11.2.2.6 Handling and support

Handling and support lugs may be supplied for hangoff during installation and for handling during shipping and installation.

11.2.3 Impact testing of materials

Impact testing is not required.

11.2.4 Testing

No factory acceptance testing is required.

11.3 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger

11.3.1 General

The 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger suspends the surface casing and through its running/tieback tool provides a connection for casing/riser tie-back to the low pressure surface BOP.

Internally the casing hanger has a landing shoulder for supporting the wellhead housing.

11.3.2 Design

The design of the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger shall comply with 5.1. When generating the design and technical specification for the casing hanger the following shall be considered:

— transfer of riser loads to conductor housing;

— lockdown of surface casing hanger to conductor housing;

— centralization of wellhead housing;

— mud and cement return flow by area;

— dimensional compatibility with conductor housing and wellhead housing;

— dimensional compatibility with specified bit programme.

11.3.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger:

— wellhead loads;

— riser or/and casing tieback loads;

— environmental loads;

— pressure loads;

— thermal loads.

11.3.2.2 Casing hanger ratings

The load and pressure ratings for the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger is a function of the tubular grade of material and wall section. Manufacturers shall determine and document the load/pressure ratings for casing hangers as defined below.

a) **Hanging capacity**

The manufacturer's stated hanging capacity rating for a casing hanger includes the casing thread (normally a female thread) cut into the hanger body;

b) **Pressure rating**

The manufacturer's stated pressure rating for a casing hanger includes the hanger body and the casing thread (normally a female thread) cut into the lower end of the hanger;

NOTE The user is responsible for determining the working pressure of a given weight and grade of casing.

c) **BOP test pressure**

The BOP test pressure rating for the casing hanger is the maximum pressure which may be applied to the upper portion of the hanger body. This rating specifically excludes the casing connection at the lower end of the casing hanger.

The BOP test pressure rating for the casing hanger shall be either 13,8 MPa (2 000 psi), or 20,7 MPa (3 000 psi) depending on the surface BOP. Note the user should ensure that test pressures do not exceed the capability of riser/tie-back strings;

d) **Support capacity**

The manufacturer's stated support capacity is the rated weight which the casing hanger is capable of transferring to the conductor housing. The effects of full rated internal working pressure shall be included.

11.3.2.3 Dimensions

The OD of the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger shall facilitate its being installed through the environmental pipe when used. Passage for mud and cement returns shall be considered. Internally it shall allow passage of the drill bit for the intermediate casing string; i.e. the drill bit gauge for the intermediate string plus 3 mm (1/8 in) diametrical clearance.

11.3.2.4 Top connection

The top connection will have a thread or latching profile for the running/tieback tool.

11.3.2.5 Bottom connection

The type of casing thread on the hanger shall be as specified in ISO 10423.

11.3.2.6 Pup joint

A pup joint of casing shall be installed in the factory to minimize the risk of damage to the hanger.

11.3.2.7 Flowby area

The 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger minimum flowby area shall be documented by the manufacturer.

11.3.3 Testing

11.3.3.1 Performance verification testing

Performance verification testing of the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger shall conform to 5.1.7. Performance verification testing for internal pressure shall be performed to verify the structural integrity of the hanger and shall be independent of the casing grade and thread.

11.3.3.2 Factory acceptance testing

Factory acceptance testing of the 508 mm (20 in) or 473 mm (18 5/8 in) casing hanger need not include a hydrostatic test. A dimensional check or drift test shall be performed on the hanger to verify the minimum vertical bore meets the manufacturers specification.

11.4 Wellhead housing

11.4.1 General

The wellhead housing lands inside the surface casing hanger. It provides pressure integrity for the well, suspends the intermediate and subsequent casing strings, the tubing hanger when installed and reacts external loads back into the surface casing hanger. Internally it has a landing shoulder for the subsequent hangers and an internal profile for a running/tie-back tool. The subsea tree attaches and seals to the upper connection after the drilling phase is complete.

11.4.2 Design

11.4.2.1 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing the high pressure housing:

- riser forces (drilling, production and workover);
- fatigue loads;
- subsea tree loads;

— pressure;

— radial loads;

— thermal loads;

— environmental loads;

— flowline loads;

— suspended casing loads;

— surface casing hanger/conductor housing reactions;

— tubing hanger reactions;

— hydraulic connector loads.

11.4.2.2 Connections

a) **Top connection**
The top connection should be of a hub or mandrel type (see Figure 14) as specified by the manufacturer. The gasket profiles shall be manufactured from or inlayed with corrosion resistant material as specified in 5.3.3.

b) **Bottom connection**
The high-pressure housing attaches to the top of the intermediate casing to form the basic foundation of a subsea well. If the bottom connection is to be welded, it shall be prepared for a full penetration butt-weld. If threaded, the type of casing thread on the housing shall be as specified in ISO 10423, clause 902 or 918.

c) **Pup joint**
The wellhead housing may have a pup joint which is factory welded on to ease field installation or threaded into the housing.

11.4.3 Dimensions

a) The minimum bore of the housing must not be less than the drift diameter of the intermediate casing. The manufacturer will document the through bore size.

b) Dimensions of the wellhead pressure boundary (see Figure 14) shall be in accordance with the manufacturer's written specification.

c) The wellhead housing minimum flow-by area shall be documented by the manufacturer.

11.4.4 Rated working pressure

The MRWP for the wellhead housing pressure boundary (see Figure 14) shall be 34,5 MPa (5 000 psi), 69,0 MPa (10 000 psi) or 103,5 MPa (15 000). Selection of the rated working pressure should consider the maximum expected SCSSV operating pressure (see 5.1.2.1.1).

11.4.5 Factory acceptance testing

All wellhead housings shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic test is performed to verify the pressure integrity of the housing pressure boundary. They shall be tested to the requirements of ISO 10423:1994, clause 605, except that the tests (including PSL 2) shall have a secondary holding period of not less than 15 min.

The hydrostatic body test pressure shall be determined from the housing rated working pressure. The hydrostatic body test pressure shall not be less than specified in Table 29.

Table 29 — Test pressure

Rated working pressure		Hydrostatic body test pressure	
MPa	(psi)	MPa	(psi)
34,5	(5 000)	51,8	(7 500)
69,0	(10 000)	103,5	(15 000)
103,5	(15 000)	155,2	(22 500)

Wellhead housings shall show no visible leakage during each pressure holding period.

11.5 Casing hangers

11.5.1 General

The subsea casing hanger is installed on top of each casing string and supports the string when landed in the wellhead housing. It is configured to run through the surface BOP stack and drilling riser, land in the wellhead, and support the required casing load. It shall have provisions for an annulus seal assembly, support loads generated by BOP test pressures above the hanger and loads due to subsequent casing strings. Means shall be provided to transfer casing load and test pressure load to the high pressure housing or to the previous casing hanger.

A lockdown mechanism, if required, is used to restrict movement of the casing hanger due to thermal expansion or annulus pressure. An external flowby area allows for returns to flow past the hanger during cementing operations and is designed to minimize pressure drop, while passing as large a particle size as possible. A pup joint of casing should be installed on the hanger in the shop. This reduces the risk of damage during handling.

Drill through mudline casing hangers shall be treated as pressure-controlling equipment as defined in ISO 10423.

11.5.2 Design

11.5.2.1 Loads

As a minimum, the following loads shall be considered and documented by the manufacturer when designing casing hangers:

— suspended weight;

— overpull;

— pressure, internal and external;

— thermal;

— torsional;

— radial;

— impact.

11.5.2.2 Threaded connections

The type of casing threads on the hanger shall be as specified in ISO 10423.

11.5.2.3 Vertical bore

a) **Full opening vertical bore**

The minimum vertical bores for casing hangers shall be as given in Table 30. Equipment conforming to this requirement shall be referred to as having full opening bores.

b) **Reduced opening vertical bores**

Reduced vertical bores may also be supplied.

Table 30 — Minimum vertical bore sizes for casing hangers and wear bushings

Casing OD		Minimum vertical bore	
mm	(in)	mm	(in)
178	(7)	153	(6,03)
194	(7 5/8)	172	(6,78)
219	(8 5/8)	195	(7,66)
244	(9 5/8)	217	(8,53)
273	(10 3/4)	242	(9,53)

11.5.2.4 Outside profile

The outside profile shall be in accordance with the manufacturer's written specification.

11.5.2.5 In-wellhead casing hanger ratings

The load and pressure ratings for casing hangers installed inside the wellhead may be a function of the tubular grade of material and wall section as well as the wellhead equipment in which it is installed. Manufacturers shall determine and document the load/pressure ratings for casing hangers as defined below:

a) **Hanging capacity**

The manufacturer's stated hanging capacity rating for a casing hanger includes the casing thread (normally a female thread) cut into the hanger body.

b) **Pressure rating**

The manufacturer's stated pressure rating for a casing hanger includes the hanger body and the casing thread (normally a female thread) cut into the lower end of the hanger.

The user is responsible for determining the working pressure of a given weight and grade of casing.

c) **BOP test pressure**

The BOP test pressure rating for a casing hanger is the maximum pressure which may be applied to the upper portion of the hanger body, and to the annulus seal assembly. This rating specifically excludes the casing connection at the lower end of the casing hanger. The BOP test pressure rating for a casing hanger shall be equal to the rated working pressure of the wellhead housing that the hanger is installed in.

d) **Support capacity**

The manufacturer's stated support capacity is the rated weight which the casing hanger(s) are capable of transferring to the wellhead housing or previous casing hanger(s). The effects of full rated internal working pressure shall be included.

11.5.2.6 Flowby area

Casing hanger minimum flowby areas shall be documented by the manufacturer for each nominal size casing hanger assembly.

11.5.3 Testing

11.5.3.1 Performance verification testing

Performance verification testing of drill through mudline casing hangers shall conform to 5.1.7. Performance verification testing for internal pressure shall be performed to verify the structural integrity of the hanger and shall be independent of the casing grade and thread.

11.5.3.2 Factory acceptance testing

Factory acceptance testing of drill through mudline casing hangers need not include a hydrostatic test. A dimensional check or drift test shall be performed on the hanger to verify the minimum vertical bore. (Refer to Table 30).

11.6 Annulus seal assemblies

11.6.1 General

Annulus seal assemblies provide pressure isolation between each casing hanger and the wellhead housing. They may be run simultaneously with the subsea casing hanger, or separately. Annulus seal assemblies are actuated by various methods, including torque weight and/or hydraulic pressure.

Drill through mudline wellhead annulus seal assemblies shall be treated as pressure-controlling equipment as defined in ISO 10423.

11.6.2 Design

11.6.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the annulus seal assemblies:

— setting loads;

— thermal loads;

— pressure loads;

— releasing and/or retrieval loads.

11.6.2.2 Rated working pressure

The annulus seal assembly shall contain pressure from above equal to the rated working pressure of the casing hanger [see 11.5.2.5 b)].

11.6.2.3 Outside profile

The outside profile shall be in accordance with the manufacturer's written specification.

11.6.2.4 Lockdown

The annulus seal assembly shall be locked to the casing hanger and/or wellhead housing using a lock mechanism that allows retrieval without damage to the seal surfaces, in the event of seal failure.

11.6.2.5 Emergency annulus seal assemblies

Emergency annulus seal assemblies which position the seal in a different area or use a different seal mechanism may be supplied. They shall meet all requirements of 11.6.2.

11.6.3 Factory acceptance testing

Factory acceptance testing is not required.

11.7 Bore protectors and wear bushings

11.7.1 General

A bore protector protects annulus seal assembly sealing surfaces inside the wellhead housing before casing hangers are installed. After a casing hanger is run, a corresponding size wear bushing is installed to protect the remaining annular sealing surfaces and the previously installed annular seal assemblies and casing hangers. They are generally not pressure retaining devices. However, wear bushings may be designed for BOP stack pressure test loading.

11.7.2 Design

11.7.2.1 Loads

The following loads shall be considered and documented by the manufacturer when designing the bore protectors or wear bushings:

— BOP test pressure loading;

— radial loads.

Bore protectors or wear bushings do not need to meet the requirements of clause 5.

11.7.2.2 Vertical bores

a) **Full opening vertical bore**

The minimum vertical bore of the bore protector shall be as given in Table 31. The minimum vertical bore through wear bushings shall be as given in Table 30. Bore protectors and wear bushings conforming to these requirements shall be referred to as having full opening bores.

b) **Reduced opening vertical bore**

Reduced vertical bores may also be supplied.

Table 31 — Minimum vertical bores for bore protectors

Nominal BOP stack sizes		Minimum vertical bore	
mm	(in)	mm	(in)
346	(13 5/8)	312	(12,31)

11.7.2.3 Outside profile

The outside profile shall be in accordance with the manufacturer's written specifications.

11.7.2.4 Rated working pressure

Bore protectors and wear bushings are not normally designed to retain pressure.

11.7.2.5 Lockdown/antirotation

Means shall be provided to restrain or lock the wear bushings or bore protector within the housing. This feature may also be designed to minimize rotation.

11.7.3 Materials

The materials used in bore protectors and wear bushings shall comply with the manufacturer's written specifications.

11.7.4 Testing

Bore protectors and wear bushing shall be dimensionally inspected to confirm minimum vertical bore.

11.8 Abandonment caps

11.8.1 Description

Abandonment caps are typically used during temporary abandonment and protect internal hanger profiles, threads and seal areas from marine growth, mechanical damage and debris. They may also provide a pressure sealing barrier to the environment.

11.8.2 Design

The design of abandonment caps shall comply with 5.1. Pressure and any external loads applied during installation, pressure relief and retrieval shall be considered and documented by the manufacturer in the design of abandonment caps. Pressure-containing abandonment caps shall be equipped with a means of relieving pressure prior to removal.

11.9 Running, retrieving and testing tools

Tools for running, retrieving, and for testing all drill through mudline wellhead components including guidance equipment, housings, casing suspension equipment, annulus sealing equipment and protective devices are beyond the scope of this part of ISO 13628.

Refer to annex H for recommended guide lines for the design and testing of this equipment.

Wash ports may be provided in the running tools to allow for cleaning of cement from around the previously run hanger/housing.

12 Purchasing guide lines

12.1 General

This clause provides recommended guide lines for inquiry and purchase of equipment covered by this part of ISO 13628.

12.2 Typical wellhead and tree configurations

Examples of typical wellhead and tree configurations are shown in the annex A to annex F.

12.3 Product specification levels

PSLs are defined in 5.2, 5.3 and 5.4. PSLs apply to all pressure-containing and pressure-controlling parts. Determination of the PSL is the responsibility of the purchaser. The following are recommendations for selection:

PSL 2 Recommended for working pressures 34,5 MPa (5 000 psi) and below, general service.

PSL 3 Recommended for sour service, all working pressures and general service above pressures of 34,5 MPa (5 000 psi). Other considerations which may lead the user to consider PSL 3 are water depth, infrastructure, difficulty of intervention, acceptance of risk, location, sensitivity of environment, useful field life, etc.

PSL 3G Same recommendations as for PSL 3, with additional consideration for wells which are gas producers, have a high gas/oil ratio or will be used for gas injection.

12.4 Material class rating

Material class rating shall be determined in accordance with the following notes and selection table.

To select the desired material class in Table 1, the purchaser may determine the corrosivity of the retained fluid by considering the various environmental factors and production variables listed below:

- pressure;
- temperature;
- composition of produced fluid (CO_2, H_2S, chlorides, etc.);
- future operations which could affect pressure, temperature or fluid content;
- possibility of government regulations;
- pH of water or brine;
- use of scale, paraffin, corrosion or other types of inhibitors;
- possibility of acidizing;
- anticipated production rates;
- potential for erosion.

Corrosion, stress-corrosion cracking, erosion-corrosion, and sulfide stress cracking are all influenced by the interaction of the environmental factors and the production variables. Other factors not listed may also influence fluid corrosivity.

The purchaser shall determine if materials must meet ANSI/NACE MR0175 for sour service. ANSI/NACE MR0175 is only concerned with the metallic material requirements to prevent sulphide stress cracking and not with resistance to corrosion. A second consideration should be to determine the carbon dioxide partial pressure, which generally relates to corrosivity in wells as given in Table 32.

Table 32 — Material class rating

Retained fluids	Relative corrosivity of retained fluid	Partial pressure of CO_2 MPa (psi)	Recommended materials class [a]
General service	Non corrosive	< 0,05 (7,0)	AA
General service	Slightly corrosive	0,05 to 0,21 (7,0 to 30,0)	BB
General service	Moderately to highly corrosive	> 0,21 (30,0)	CC
Sour service	Non corrosive	< 0,05 (7,0)	DD
Sour service	Slightly corrosive	0,05 to 0,21 (7,0 to 30,0)	EE
Sour service	Moderately to highly corrosive	> 0,21 (30,0)	FF
Sour service	Very corrosive	> 0,21 (30,0)	HH

[a] As defined in Table 1.

Annex A
(informative)

Conventional subsea trees

Conventional subsea trees are installed on the wellhead, after the subsea tubing hanger has been installed through the drilling BOP stack and landed and locked into the wellhead. The production flowpath is through the valves mounted in the vertical bore(s) and either out of the top of the tree during workover and testing [in special applications production (injection) may be via the top of the tree] and during production (injection) via the production outlet which branches off the vertical bore.

The subsea tree may have a concentric bore or may have multiple bores. Annulus access may be through one of the tree bores or it may be in a tubing head spool below the tree.

The production outlet may be at 90° to the production bore or may be angled to best suit flow requirements. In TFL trees the outlets are swept in at 15° maximum to the production bore to facilitate the passage of pump down tools.

Figures A.1 and A.2 highlight the major items of equipment in conventional subsea trees. The arrangements shown are typical and are not to be construed as requirements.

Major items of equipment in a subsea tree are:

— tree connectors and tubing head spools;

— tree stabs and seal subs;

— valves, valve blocks and valve actuators;

— chokes and choke actuators;

— TFL wye spool entry spool;

— tree cap;

— tree cap running tool;

— tree piping;

— tree guide frame;

— tree running tool;

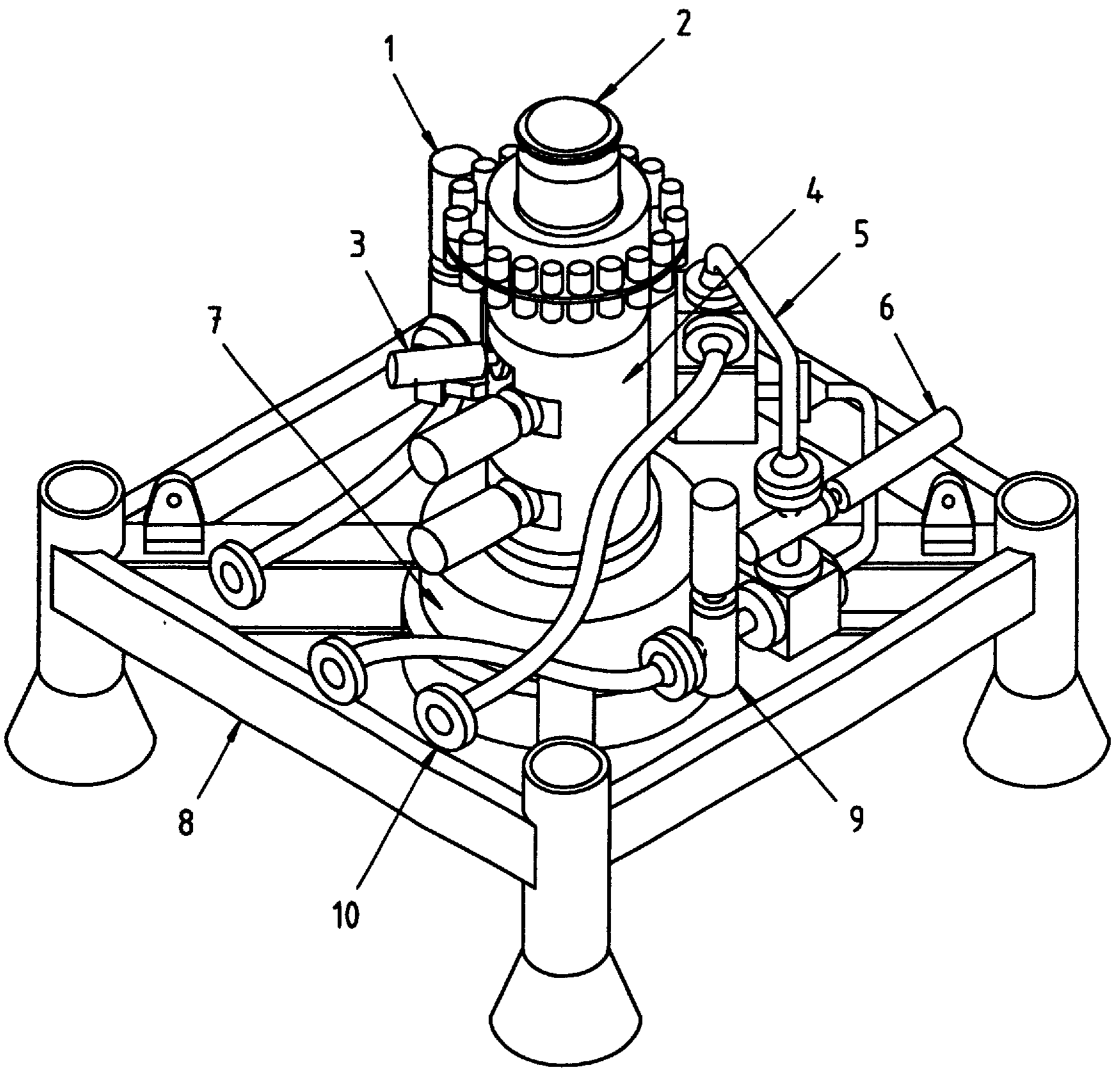
— flowline connectors;

— flowline connector support frame;

— subsea chokes and actuators;

— tree mounted control interfaces;

— control pod interface.

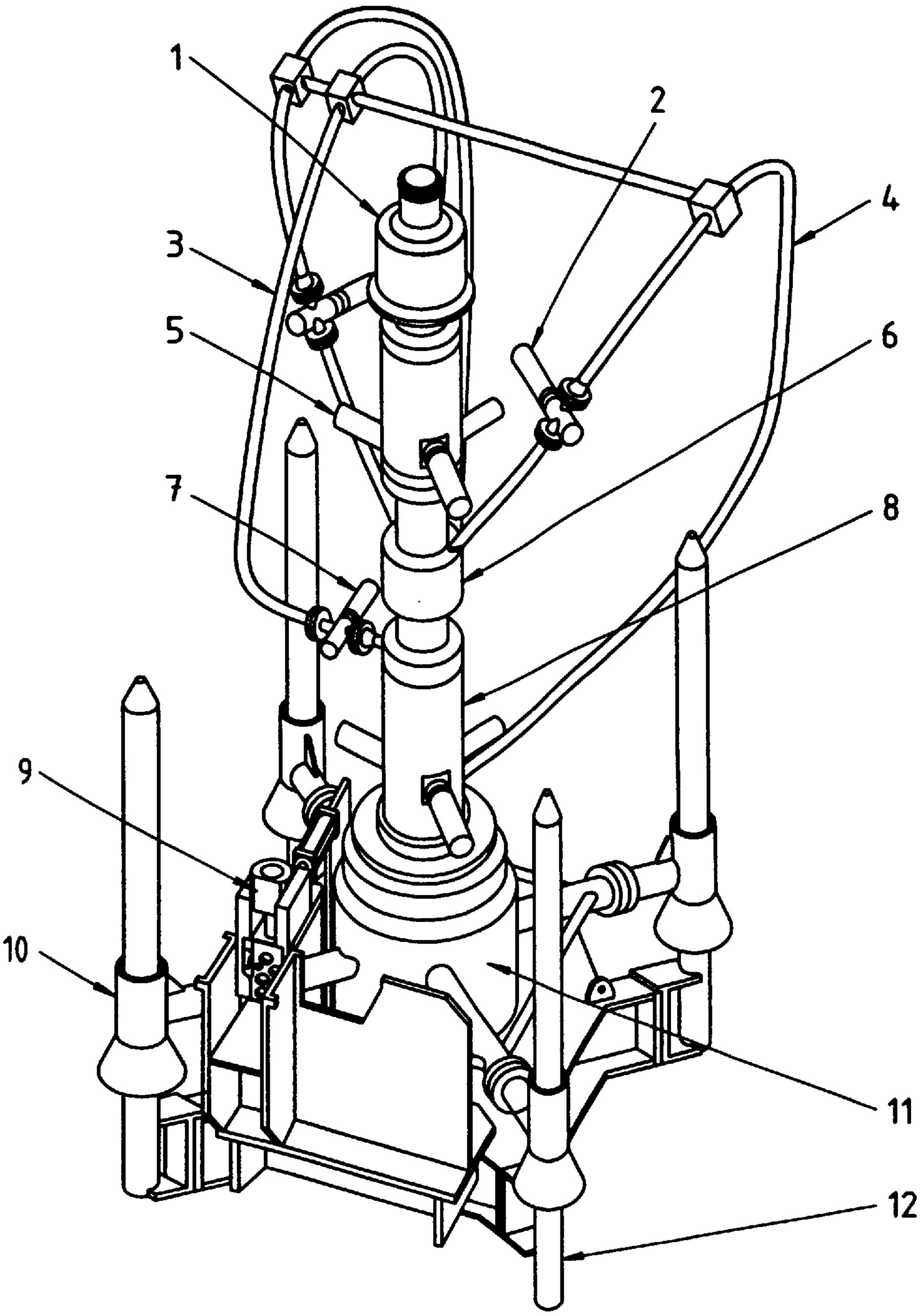


Key

1 Production wing valve
2 Tree cap
3 Production swab valve
4 Master valve block
5 Flow loop
6 Crossover valve
7 Tree connector
8 Tree guide frame
9 Annulus wing valve
10 Flow line connection

NOTE Wellhead system not shown for clarity.

Figure A.1 — Non-TFL tree



Key

1 Tree cap assembly
2 Wing valve
3 Annulus loop
4 TFL flow loop
5 swab valves
6 Wye spool and diverter
7 Annulus wing valve
8 Master valve block
9 Flow line connector
10 Tree guide frame
11 Tree connector
12 Wellhead guidebase

NOTE Wellhead system not shown for clarity.

Figure A.2 — TFL tree

Annex B
(informative)

Horizontal subsea trees

A number of options are available for horizontal tree arrangements. These offer different benefits for installation, retrieval and maintenance. These are addressed for information only. No attempt is made within this part of ISO 13628 to evaluate or recommend an option.

Horizontal subsea trees may be installed after drilling and installation of the complete wellhead system and prior to installation of the tubing completion and tubing hanger. For this mode of operation the BOP is installed on top of the horizontal subsea tree and the tubing hanger and tubing completion is run through the BOP and landed off on a landing shoulder in the bore of the horizontal subsea tree. The production flowpath exits horizontally through a branch bore in the tubing hanger between radial seals and connects to the aligned production outlet. A typical tree of this type is illustrated in Figure B.1. The above arrangement requires that the tubing completion be retrieved prior to retrieving the tree.

An alternative arrangement where the tubing is suspended in the wellhead housing and an upper dummy tubing hanger is landed in the horizontal tree and is used to seal between the tubing hanger and the production outlet of the horizontal tree. This is illustrated in Figure B.2. This arrangement allows the tree to be retrieved without pulling the tubing completion.

A further system (generally referred to as the "drill-through" horizontal tree) which allows the tree to be installed immediately after the wellhead housing is landed is illustrated in Figure B.3. This system allows drilling and installation of casing strings to be performed through the horizontal tree minimizing the number of times the BOP stack has to be run and retrieved. The wellhead may be of a smaller size than the nominal bore of the horizontal tree.

Both the arrangements shown in Figure B.2 and Figure B.3 require annulus porting through the tubing hanger and a means of isolating the port if the tree is removed.

Horizontal trees may also be used with conventional mudline suspension equipment and drill-through mudline suspension equipment and may additionally be configured for artificial lift completions, such as electric submersible pumps or hydraulic submersible pumps.

Horizontal subsea trees use many of the same items of equipment as conventional trees.

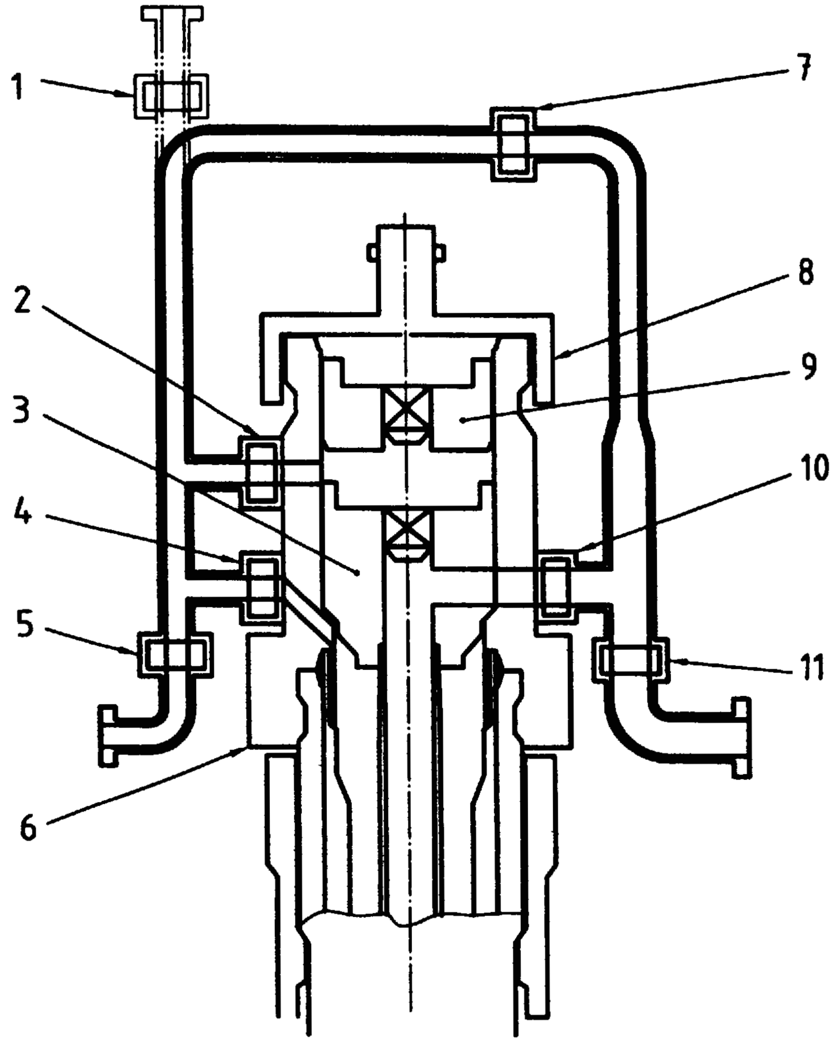
However equipment which differs significantly is:

— tree body;

— tubing hanger;

— dummy tubing hanger (if used);

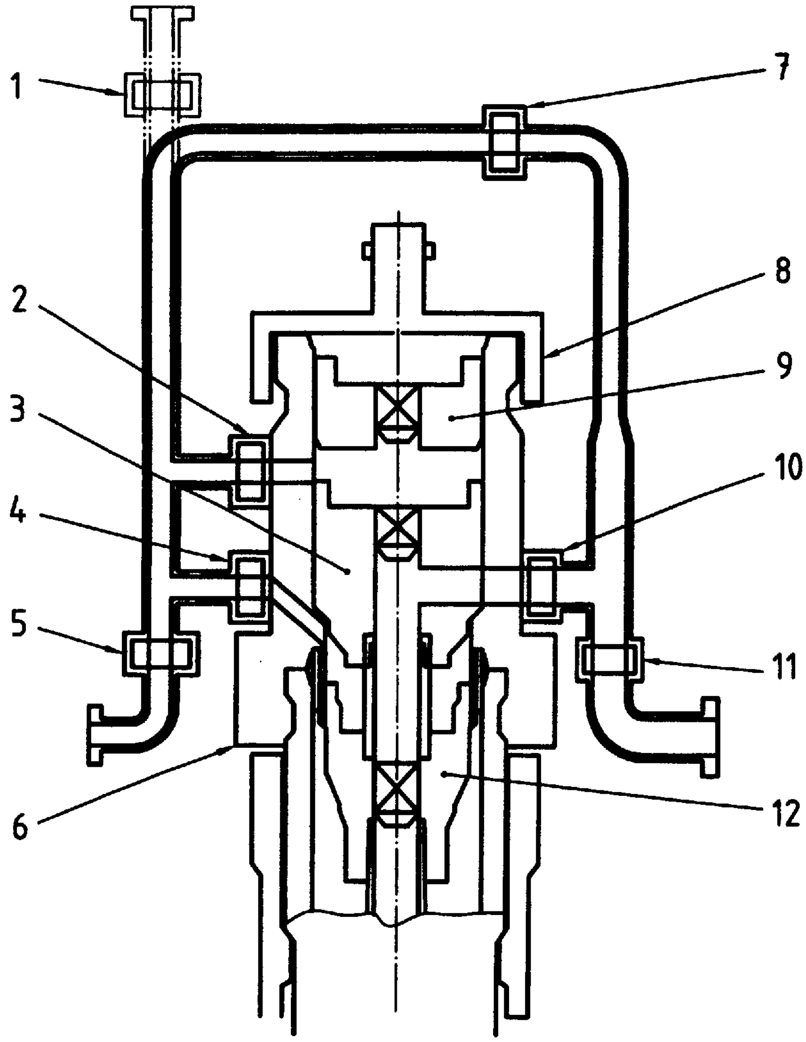
— tree cap.



Key

1 Workover valve (Alternative position)
2 Workover valve
3 Tubing hanger
4 Annulus master valve
5 Annulus wing valve
6 Tree connector
7 Crossover valve
8 Debris cap
9 Internal isolation cap
10 Production master valve
11 Production wing valve

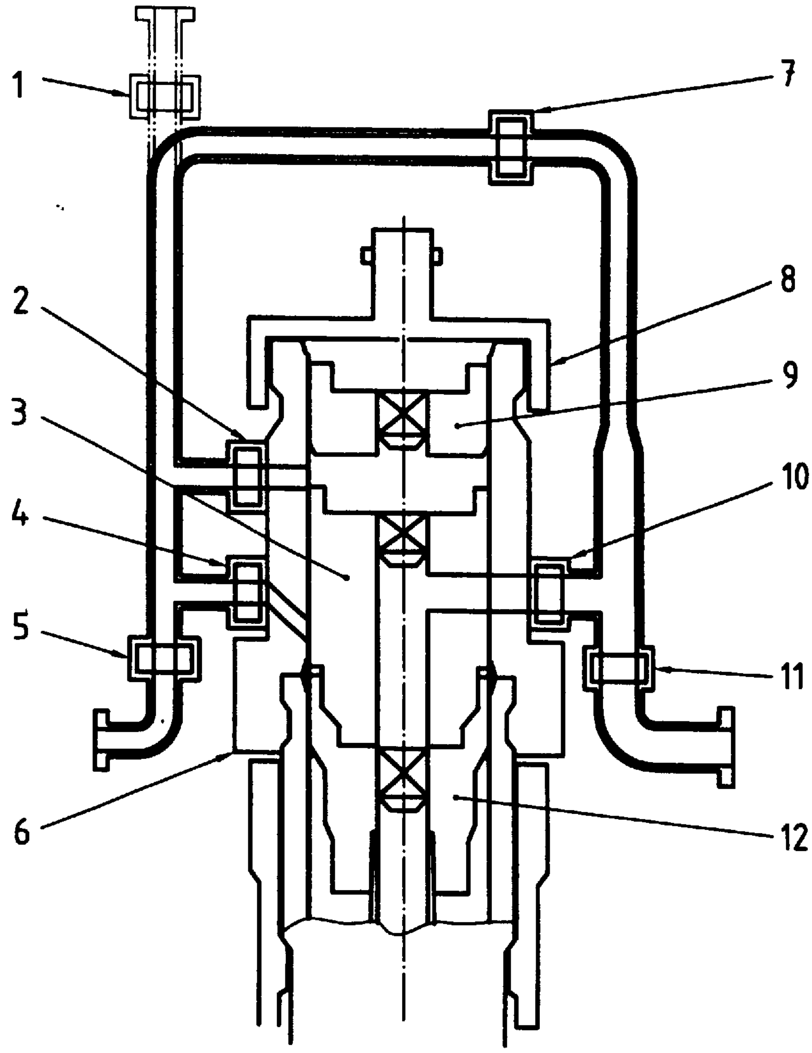
Figure B.1 — Horizontal tree — Tubing hanger in tree



Key

1 Workover valve (Alternative position)
2 Workover valve
3 Dummy tubing hanger
4 Annulus master valve
5 Annulus wing valve
6 Tree connector
7 Crossover valve
8 Debris cap
9 Internal isolation cap
10 Production master valve
11 Production wing valve
12 Tubing hanger

Figure B.2 — Horizontal tree — Tubing hanger in wellhead



Key

1 Workover valve (Alternative position)
2 Workover valve
3 Dummy tubing hanger
4 Annulus master valve
5 Annulus wing valve
6 Tree connector
7 Crossover valve
8 Debris cap
9 Internal isolation cap
10 Production master valve
11 Production wing valve
12 Tubing hanger

Figure B.3 — Horizontal tree drill-through

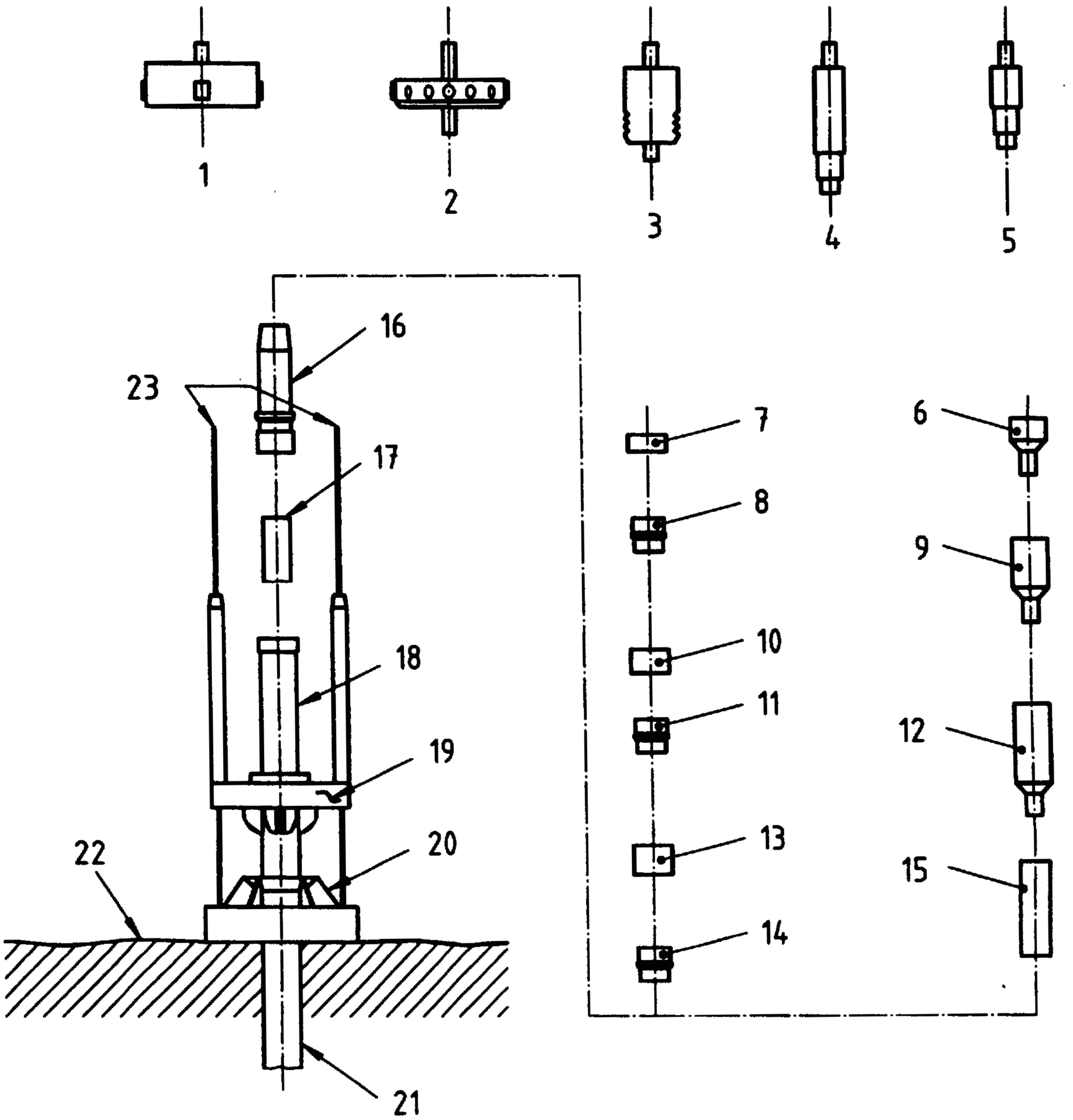
Annex C
(informative)

Subsea wellhead

The subsea wellhead is normally run from a floating drilling rig and is located at the mudline. It supports the casing strings and seals off the annuli between them. It is used in conjunction with a subsea BOP stack which locks and seals to the high pressure wellhead housing. The subsea tree locks and seals to the high pressure housing after drilling is complete. Figure C.1 illustrates the items of equipment used in a subsea wellhead.

Major items of equipment used with subsea wellhead are:

- TGB;
- PGB;
- conductor housing;
- wellhead housing;
- casing hangers;
- seal assemblies;
- guidebases;
- bore protectors and wear bushings;
- corrosion caps;
- running tools.



Key

1 Temporary guidebase running tool
2 Housing running tool, 762 mm (30 in)
3 High-pressure housing running tool
4 Casing hanger running tool (drillpipe or fullbore)
5 Test tool
6 Wear bushing, 178 mm (7 in to 7 5/8 in)
7 Annulus seal assembly 245 mm × 178 mm (9 5/8 in to 10 3/4 in × 7 in to 7 5/8 in)
8 Casing hanger, 178 mm (7 in to 7 5/8 in)
9 Wear bushing, 245 mm (9 5/8 in to 10 3/4 in)
10 Annulus seal assembly, 340 mm × 245 mm (13 3/8 in × 9 5/8 in to 10 3/4 in)
11 Casing hanger, 245 mm (9 5/8 in to 10 3/4 in)
12 Wear bushing, 340 mm (13 3/8 in)
13 Annulus seal assembly, 508 mm × 340 mm (20 in × 13 3/8 in)
14 Casing hanger, 340 mm (13 3/8 in)
15 Housing bore protector
16 High-pressure wellhead housing
17 Surface casing; normally 508 mm (20 in)
18 Low pressure conductor housing; normally 762 mm (30 in)
19 PGB
20 TGB
21 Conductor casing, 762 mm (30 in)
22 Sea floor
23 Guide lines

Figure C.1 — Subsea wellhead

Annex D
(informative)

Subsea tubing hanger

Subsea tubing hangers are located in the wellhead, tubing spool (wellhead conversion assembly) or horizontal tree.

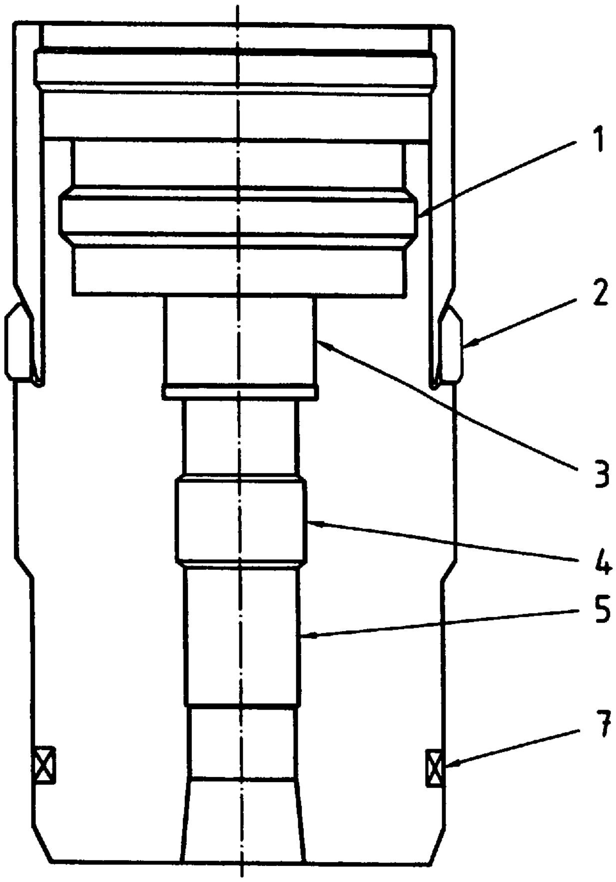
They suspend the tubing, seal off the production annulus and in the case of conventional trees, provide sealing pockets for the production, annulus and control stabs. In horizontal trees they have seals which straddle the horizontal production outlet.

Tubing hangers having multiple bores require orientating relative to the PGB, to ensure that the tree will engage with the tubing hanger when installed. It is normal to orientate tubing hangers with horizontal production outlets to give a smooth flow passage between the tubing hanger and horizontal tree. Concentric tubing hangers do not necessarily require orientation, unless needed as a consequence of providing downhole instrumentation.

After installation the tubing hanger is locked into the mating wellhead, spool, etc. to resist the force due to pressure in the production casing and to resist thermal expansion. Lock mechanisms may be mechanically or hydraulically actuated depending on water depth and specific project requirements.

Major elements of the tubing hanger system are:

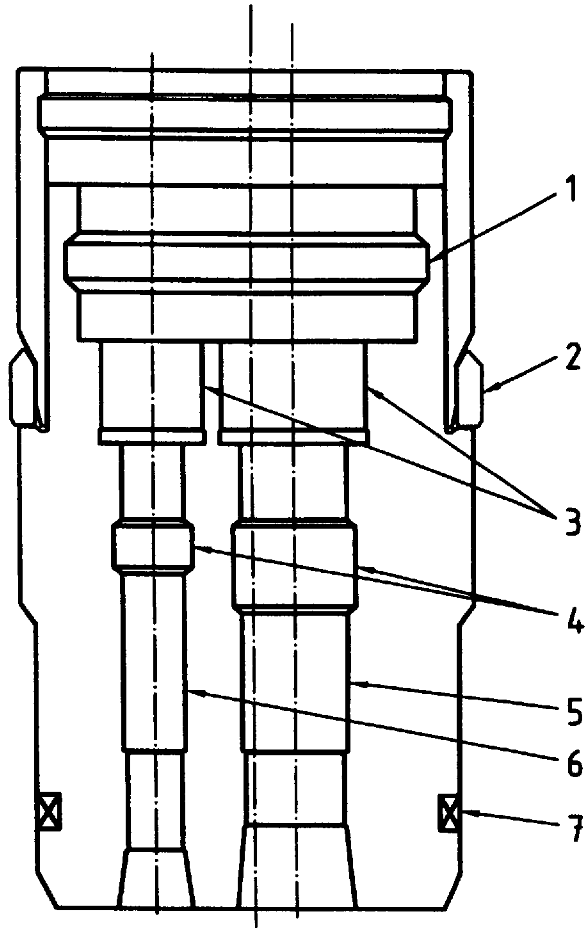
- tubing hanger;
  - concentric (see Figure D.1),
  - multiple bores (see Figure D.2),
  - horizontal tree (see Figure D.3);
- tubing hanger running tool;
- orientation device;
- miscellaneous tools.



Key

1 Running tool latching groove
2 Lockdown
3 Stab sub-seal pockets
4 Wireline plug profiles
5 Production bore
6 Annulus bore
7 Seal

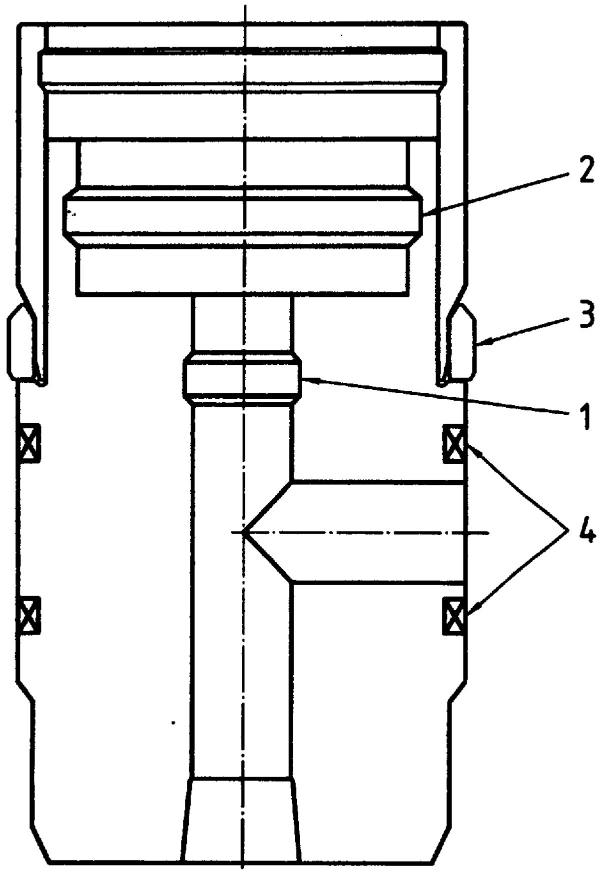
Figure D.1 — Concentric tubing hanger



Key

1 Running tool latching groove
2 Lockdown
3 Stab sub-seal pockets
4 Wireline plug profiles
5 Production bore
6 Annulus bore
7 Seal

Figure D.2 — Tubing hanger with multiple bores



Key

1 Wireline plug profile or closure device

2 Running tool latching groove

3 Lockdown

4 Seal

Figure D.3 — Tubing hanger for horizontal tree

Annex E
(normative)

Conventional mudline suspension and conversion systems

E.1 General

Conventional mudline suspension equipment is used to suspend casing weight at or near to the mudline, to provide pressure control and to provide annulus access to the surface wellhead. Mudline equipment is used when drilling with a bottom-supported rig or platform and provides for drilling, abandonment, platform tieback completion and subsea completion. During drilling/workover operations the BOP is located at the surface. The casing annuli are not sealed at the mudline suspension therefore it is necessary to install mudline conversion equipment prior to installing a tubing completion and subsea tree.

An annulus seal assembly is normally installed to seal off between the intermediate casing and the production casing. Tieback adapters and tubing hanger spools (wellhead adaptors) are used to provide a preparation to accept the tubing hanger and a profile to which the tree can be locked and sealed.

Major items of equipment used with conventional mudline equipment are:

— landing and elevation ring;

— casing hangers;

— casing hanger running and tieback tools;

— abandonment caps;

— mudline conversion tieback adapters;

— mudline conversion tubing hanger spools.

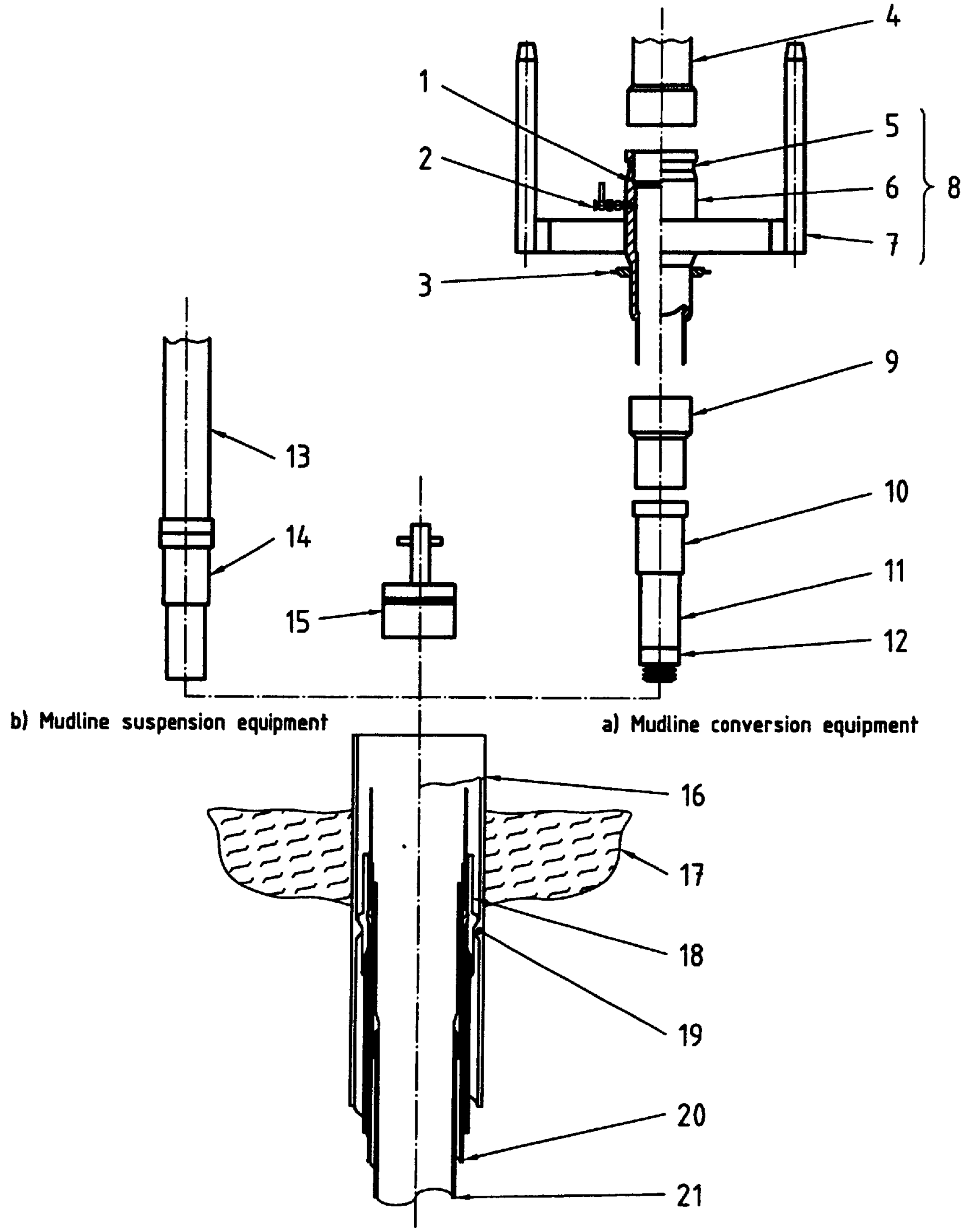
Figure E.1 illustrates the items of equipment used in conventional mudline suspension and conversion equipment.

E.2 Calculation of pressure ratings for conventional mudline suspension equipment

E.2.1 Introduction

The purpose of this annex is to define the methods to be used for calculating the rated working pressure and test pressure for conventional mudline equipment only, which are consistent with accepted engineering practice. Mudline equipment design is a unique combination of tubular goods and hanger equipment, and therefore these methods and allowable stresses are not intended to be applied to any other type of equipment. Fatigue analysis, thermal expansion considerations and allowable values for localised bearing stress are beyond the scope of these rated working pressure calculations.

As an alternative to the method presented in this annex, the designer may use the rules in [20], Appendix 4, modified in accordance with ISO 10423. In this case bending stresses in wall section discontinuities can be treated as secondary stresses. However, when using this alternative method, the calculation for rated working pressure must be made in combination with loads applied by the rated running capacity (if applicable) and the rated hanging capacity as well as thermal loads. The designer shall ensure that strains resulting from these higher allowable stresses do not impair the function of the component, particularly in seal areas.



Key

1 Tubing hanger profile
2 Annulus outlet
3 Structural support ring (optional)
4 Workover completion riser
5 Connector profile
6 Wellhead adapter
7 Guide structure
8 Tubing spools
9 Annulus seal assembly
10 Tieback adapter
11 Casing
12 Tieback tool (tieback sub)
13 Casing riser (to jack-up)
14 Casing hanger running tools (landing subs) or tieback tools (tieback subs)
15 Abandonment cap
16 762 mm (30 in) conductor casing
17 Mudline
18 508 mm (20 in) casing hanger
19 762 mm (30 in) casing hanger
20 340 mm (13 3/8 in) casing hanger
21 245 mm (9 5/8 in) casing hanger

Figure E.1 — Conventional mudline conversion and suspension equipment

E.2.2 Determination of applied loads

For each component to be rated, the most highly stressed region in the component when subjected to the worse case combination of internal pressure and pressure end load shall be established. In performing this assessment, bending and axial loads other than those induced by the pressure end caps and threaded end connections required for imposition of pressure end load may be ignored. Specifically, axial or bending loads caused by the connection of the component to other pieces of equipment in service need not be considered.

In establishing the most highly stressed region of the component, considerable care must be used to insure that loads applied through any casing threads which are machined into the component are included. The presence of threads cut into the wall of a component and the pressure end loads imparted to the main body of the component through these threads results in local bending stress which must be considered. The general shape of the main body of the component may also result in section bending stress, especially when pressure end load is added. These shape effects shall also be considered when determining the loads on the component.

E.2.3 Determination of stresses

After the location of the highest stress for any given component and loading condition has been determined, the stress distribution across the critical section shall be linearized to establish the membrane stress (S_m), local bending stress (S_b) and peak stress (F) in the section; see Figure E.2 (refer to ISO 13625). The linearization operation shall be performed on each component of stress. The individual linearized components shall then be used to calculate a von Mises equivalent stress through the cross section. The von Mises equivalent stress or Distortion Energy stress (S_e) shall be calculated as follows:

$$S_e = [S_x^2 + S_y^2 + S_z^2 - S_xS_y - S_xS_z - S_yS_z + 3\,(S_{xy}^2 + S_{xz}^2 + S_{yz}^2)] \qquad \text{(E.1)}$$

where

S_x, S_y, S_z are the component normal stresses at a point;

S_{xy}, S_{xz}, S_{yz} the component shear stresses at a point;

subscripts x, y and z refer to the global coordinate system.

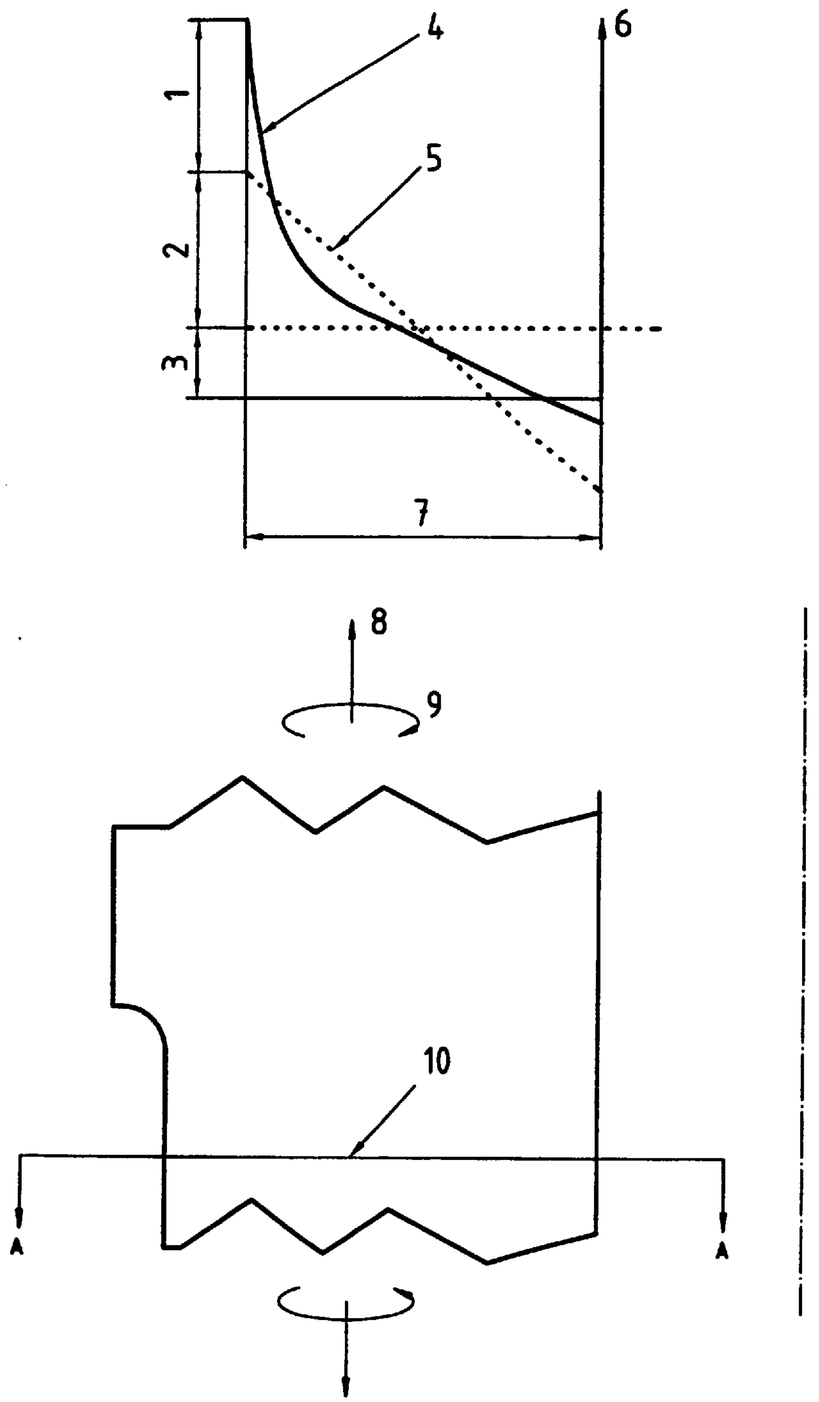
The linearization operation can be done by hand calculation but is more often done using a computer program. If a computer program or FEA post-processing program is used, caution shall be used to verify that the program is calculating the linearization stresses correctly. A check on computer output is highly recommended. One such simple check for FEA post-processing programs is to construct an FEA model of a simple beam in four-point bending. This model should be analysed for plane strain conditions and should have a beam depth made up of at least five elements. The linearized von Mises stress through the centre section of such a beam should produce no von Mises membrane stress.

The von Mises stress values of interest in the cross section of the component being studied are the linearized membrane (net section) stress, and the linearized local bending stress as shown in Figure E.2. These values consider the multiaxial stress condition at a point since they are von Mises equivalent stresses.

E.2.4 Allowable stress levels for working and test conditions

The allowable stress levels for test and working conditions are based on percentages of membrane plus bending and membrane only stress required to yield the material. For the case of the stresses used in this, the local membrane and bending stress calculated in E.2.3 shall be considered primary stresses since they are the stresses required to provide static equilibrium of the section with the applied pressure and end loads.

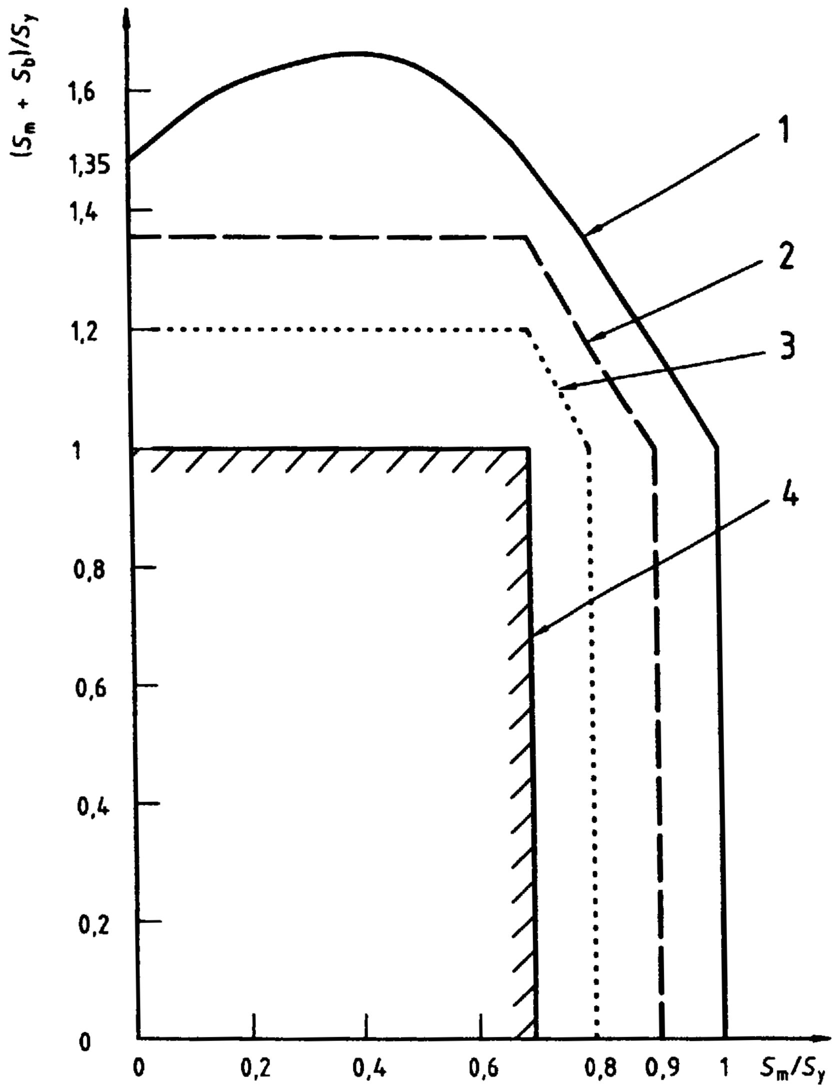
In order to understand what allowable levels should be used for this case, the limiting situation of full section yielding must be defined. Assuming the simple case of a rectangular beam and an elastic-perfectly plastic material, a plot of limiting membrane plus bending versus membrane-only stress can be made (refer to [17] and [20]. Figure E.3 shows the limiting values of various combinations of membrane plus bending and membrane-only stresses normalized using the minimum specified material yield



Key

1 Local peak stress, F
2 Local bending stress, S_b
3 Net section membrane stress, S_m
4 Total stress distribution
5 Equivalent linear distribution
6 Stress
7 Thickness
8 Tensile load
9 Local bending moment
10 Vertical plane through axisymmetric part

Figure E.2 — Stress distribution, axisymmetric cross-section, mudline suspension components



Key

1 Limit stress

2 Test pressure limit

3 Rated working pressure for suspension equipment

4 Rated working pressure for conversion equipment

S_m = membrance stress

S_b = bending stress

S_y = yield stress

Figure E.3 — Limiting stress values mudline suspension components

strength (S_y). The limit stress ratio for membrane only is 1,0 and for bending only the limit is 1,5. If a membrane stress less than 2/3 S_y is added to a large bending stress, the membrane plus bending stress ratio may exceed 1,5. This is due to the stiffening effect of the membrane stress and shifting of the beam's neutral axis. This increase in bending capacity when axial load is applied is generally ignored.

E.2.5 Test pressure

For the purposes of this part of ISO 13628, the allowable von Mises stresses for hydrostatic test conditions on both suspension and conversion equipment are as follows:

Membrane stress:

$$S_m < 0,90\ S_y \qquad \text{(E.2)}$$

Membrane plus bending stress:

$S_m + S_b < 1,35\ S_y$ for $S_m < 0,67\ S_y$

$S_m + S_b < 2,15\ S_y - 1,2\ S_m$ for $0,67\ S_y < S_m < 0,90\ S_y$

The allowable test pressure shall be that needed to cause any of the stress allowable to occur in the critical cross section of the component when pressure and end loads due to test end caps or plugs are considered. It is noted that the above limits, shown in Figure E.3 for clarity, are identical to those given in [20] Part AD, for hydrostatic test conditions.

E.2.6 Rated working pressure

E.2.6.1 Mudline suspension equipment

For the purposes of this part of ISO 13628, the allowable von Mises stresses for working conditions for mudline suspension equipment are as follows:

Membrane stress:

$$S_m < 0,80\ S_y \quad \text{(E.3)}$$

Membrane plus bending stress:

$S_m + S_b < 1,2\ S_y$ for $S_m < 0,67\ S_y$

$S_m + S_b < 2,004\ S_y - 1,2\ S_m$ for $0,67\ S_y < S_m < 0,8\ S_y$

The rated working pressure shall be that needed to cause these stresses to occur in the critical cross section of the component being considered. These limits are about 90 % of test conditions.

E.2.6.2 Mudline conversion equipment

For the purposes of this part of ISO 13628, the allowable von Mises stresses for working conditions for mudline conversion equipment are as follows:

Membrane stress:

$$S_m < 0,67\ S_y \quad \text{(E.4)}$$

Membrane plus bending stress:

$S_m + S_b < S_y$

The rated working pressure shall be that needed to cause these stresses to occur in the critical cross section of the component being considered. These limits are about 75 % of test conditions. The conditions coincide with the normal design stress limit given in [20]. It is to be noted that the membrane stress limit for conversion equipment operating condition is more conservative than that for suspension equipment. This is to account for the fact that the suspension equipment is used in service as a part of the casing string. Casing string components typically have higher allowable stress limits than completion or production equipment.

Annex F
(informative)

Drill-through mudline suspension systems

Drill-through mudline suspension equipment is used to suspend casing weight at or near to the mudline and to provide pressure control. Drill-through mudline suspension equipment is used when drilling with a bottom-supported rig when it is anticipated that the well may be completed subsea. During drilling, workover and completion operations the BOP is located at the surface. The system differs from conventional mudline suspension in that the surface casing is suspended from a wellhead housing and subsequent casing strings use wellhead like hangers and annulus seal assemblies. The hangers have positive landing shoulders, therefore their OD is normally too large to allow them to be run through casing tiebacks. It is usual to use risers having a pressure rating and bore equivalent to the surface BOP for installation of casing hangers, seal assemblies, internal abandonment caps and tubing hangers. The wellhead housing contains the necessary profile for locking down the tubing hanger and has an external profile to which the subsea christmas tree can be locked, therefore drill through mudline requires no conversion equipment.

Major items of equipment used with drill through mudline suspension are:

— conductor housing;

— surface casing hanger;

— wellhead housing;

— casing hangers;

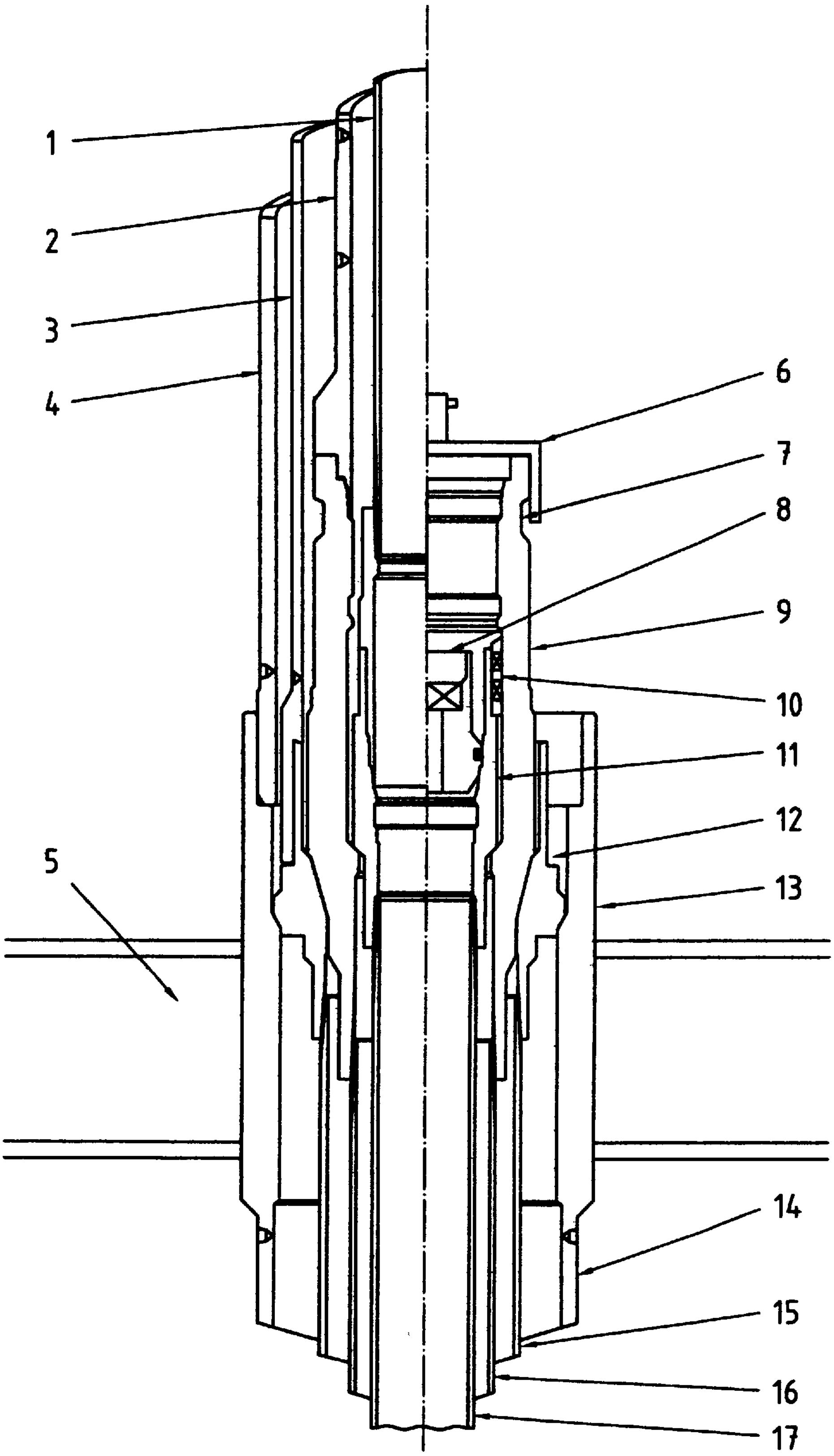
— annulus seal assemblies;

— bore protectors and wear bushings;

— abandonment caps;

— running, retrieving and test tools.

Figure F.1 illustrates the items of equipment used in drill through mudline suspension systems.



Key

1. 244 mm to 273 mm (9 5/8 in to 10 3/4 in) casing
2. 406 mm (16 in) riser
3. 610 mm (24 in) riser
4. Environmental tie-back pipe
5. Guidance equipment
6. Abandonment cap
7. Connector profile
8. Abandonment cap
9. Wellhead housing
10. Seal assembly
11. Production casing hanger
12. 473 mm to 508 mm (18 5/8 in to 20 in) hanger
13. Conductor housing
14. 762 mm (30 in) conductor
15. 473 mm to 508 mm (18 5/8 in to 20 in) casing
16. 340 mm (13 3/8 in) casing
17. 244 mm to 273 mm (9 5/8 in to 10 3/4 in) casing

a) Drilling mode

b) Temporary abandonment mode

Figure F.1 — Drill through mudline suspension system

Annex G
(normative)

Recommended flange bolt torques

Table G.1 — Recommended flange bolt torque

	B7M material 1/2 Yield stress (40 000 psi) Stress 276 MPa				B7 material 1/2 Yield stress (52 500 psi) Stress 362 MPa				B7 material 2/3 Yield stress (70,000 PSI) Stress 483 MPa			
	Bolt tension		Make up torque		Bolt tension		Make up torque		Bolt tension		Make up torque	
Bolt size	(lbf)	kN	(ft lbs)	N·m	(lbf)	kN	(ft lbs)	N·m	(lbf)	kN	ft lbs	N·m
1/2 - 13 UNC	(5 674)	25,23	(45)	61	(7 448)	33,13	(59)	80	(9 930)	44,17	(79)	107
5/8 - 11 UNC	(9 026)	40,14	(86)	117	(11 846)	52,69	(113)	153	(15 796)	70,26	(151)	205
3/4 - 10 UNC	(13 355)	59,40	(150)	203	(17 528)	77,97	(196)	266	(23 371)	103,95	(263)	357
7/8 - 9 UNC	(18 482)	82,20	(239)	324	(24 257)	107,90	(313)	424	(32 344)	143,87	(418)	567
1 - 8 UN	(24 229)	107,77	(361)	489	(31 800)	141,45	(474)	643	(42 401)	188,60	(632)	857
1 1/8 - 8 UN	(31 617)	140,63	(522)	708	(41 497)	84,58	(686)	930	(55 330)	246,11	(914)	1 239
1 1/4 - 8 UN	(39 987)	177,86	(726)	984	(52 483)	233,44	(953)	1 292	(69 977)	311,26	(1271)	1 723
1 3/8 - 8 UN	(49 339)	219,48	(976)	1 323	(64 757)	288,04	(1 281)	1 737	(86 343)	384,05	(1708)	2 316
1 1/2 - 8 UN	(59 672)	265,42	(1 277)	1 731	(78 320)	348,37	(1 676)	2 272	(104 426)	464,49	(2235)	3 030
1 5/8 - 8 UN	(70 988)	315,75	(1 635)	2 217	(93 171)	414,43	(2 146)	2 910	(124 299)	552,87	(2861)	3 879
1 3/4 - 8 UN	(83 254)	370,45	(2 054)	2 785	(109 311)	486,22	(2 695)	3 654	(145 695)	648,05	(3595)	4 874
1 7/8 - 8 UN	(96 563)	429,51	(2 538)	3 441	(126 739)	563,74	(3 331)	4 516	(168 985)	751,65	(4442)	6 022
2 - 8 UN	(110 624)	492,95	(3 093)	4 193	(145 456)	646,99	(4 060)	5 505	(193 942)	862,65	(5413)	7 339
2 1/4 - 8 UN	(142 290)	632,91	(4 435)	6 013	(186 755)	830,69	(5 821)	7 892	(249 008)	1 107,59	(7761)	10 522
2 1/2 - 8 UN	(177 683)	790,33	(6 116)	8 292	(233 209)	1 037,31	(8 028)	10 844	(310 945)	1 383,08	(10703)	14 511
2 5/8 - 8 UN	(196 852)	875,60	(7 097)	9 622	(258 368)	1 149,22	(9 314)	12 628	(344 491)	1 532,30	(12420)	16 839
2 3/4 - 8 UN	(217 003)	965,23	(8 176)	11 085	(284 817)	1 266,87	(10 731)	14 549	(379 755)	1 689,15	(14308)	19 399

NOTE It is recognised that applied torque to a nut member is only one of several ways to approximate tension and unit stress in a stud bolt. Tabulated values are presented for convenience and guidance only.

Some factors which affect the relationship between nut torque and bolt stress are:

— thread pitch, pitch diameter and thread form;

— surface finish of thread faces and nut bearing surface area;

— degree of parallelism of nut bearing area with flange face;

— type of lubrication of the threads and nut bearing surface area.

The following formulae were used in establishing the values in Table G.1.

Hexagon size (heavy hex nuts) = $D(1,5) + 0,125$ in

Hexagon size (heavy hex nuts) = $D(1,5) + 3,175$ mm

a) Imperial flange bolt torque formula:

$$T = \frac{F(P)\left[(1/N) + \pi(f)(P)(\text{secant } 30°)\right]}{2(12)\left[\pi(P) - (F)(1/N)(\text{secant } 30°)\right]} + \frac{h + D + 0{,}125(F)(f)}{(4)(12)} \tag{G.1}$$

where

D is the nominal bolt diameter (in);

A_s = $(\pi/4)$ $(D - 0{,}9743/N)^2$ is the effective stress area;

F = A_s x (bolt stress) is the force or bolt tension (lbf);

T is the torque (ft·lbs);

N is the number of threads per inch;

P is the pitch diameter of thread (in);

f is the friction factor (0,13 with threads and nut bearing area well lubricated with API Bul 5A2 thread compound) (dimensionless);

h is the hexagon size (in).

b) Metric flange bolt torque formula:

$$T = \frac{F(P)\left[(1/N) + \pi(f)(P)(\text{secant } 30°)\right]}{2\left(10^2\right)\left[\pi(P) - (f)(1/N)(\text{secant } 30°)\right]} + \frac{h + D + 3{,}175(F)(f)}{(4)\left(10^2\right)} \tag{G.2}$$

where

D is the bolt diameter (mm);

A_s is the effective stress area (mm^2);

F = $A_s \times$ (bolt stress) is the bolt tension (N);

T is the torque (N·m);

N is the number of threads per millimetre;

P is the pitch diameter (mm);

f is the friction factor (dimensionless);

A_s = $(\pi/4)(D - 0{,}9743/N)^2$ (mm^2);

h is the hexagon size (mm).

NOTE Metric equivalents for bolt tension and make up torque are listed for convenience, even though inch-size bolts are recommended for use with this part of ISO 13628.

Annex H
(normative)

Design and testing of subsea wellhead running, retrieving and testing tools

H.1 General

This annex addresses the design and testing of tools for running, retrieving and testing all subsea wellhead components including guidance equipment, housings, casing suspension equipment, annulus sealing equipment and protective devices.

H.2 Design

H.2.1 Loads

As a minimum, the following loads shall be considered when designing the running, retrieving and testing tools:

— suspended weight;

— bending loads;

— pressure;

— torsional loads;

— radial loads;

— overpull;

— environmental loads.

H.2.2 End connections

Tool joints or casing threads shall be in conformance with ISO 10424. Casing threads shall be in conformance with either ISO 10423:1994, clause 902 or 918. The tool shall have an adequate dimension for tonging. The load capacity of the tool shall not be inferred from the choice of end connections for the tool.

Torque operated tools shall preferably use left hand torque for make up and right hand torque for release, to prevent backoff of casing/tubing/drill pipe threads during operation/disconnection.

H.2.3 Vertical bore

Tools with through bore shall have a sufficient ID to allow the passage of tools required for subsequent operations as in accordance with the manufacturer's written specification.

H.2.4 Outside profile

The outside profile of the tools shall be in accordance with the manufacturer's written specification. The length, outside profile and fluid bypass area shall be designed to minimize surge/swab pressure and for ease of running while tripping and circulating.

H.2.5 Load capacity

Tool load ratings shall be in accordance with the manufacturer's written specification.

H.2.6 Vent

The conductor housing running tool shall be provided with a vent or system of vents. This system of vents is used to either fill the conductor with fluid during running or to allow the passage of cuttings during a jetting operation.

H.2.7 Pressure rating

The pressure rating of the tool shall be in accordance with the manufacturer's written specification.

H.3 Materials

H.3.1 Selection

The materials used in these tools shall be chosen for strength and need not be resistant to corrosive environments and shall comply with the manufacturer's written specification.

NOTE If exposure to severe stress cracking environments is expected, special practices beyond the scope of this part of ISO 13628 may be required.

H.3.2 Coatings

Coatings shall conform to 5.1.4.8.

H.4 Testing

H.4.1 Performance verification testing

Shall conform to 5.1.7.

H.4.2 Factory acceptance testing

All tools shall be functionally tested, dimensionally inspected or gauged to verify their correct operation prior to shipment from the manufacturer's facility. Tools with hydraulic operating systems shall have the hydraulic system tested in accordance with the manufacturer's written specification. This hydrostatic test shall consist of three parts:

a) the primary pressure-holding period;

b) the reduction of the pressure to zero (atmospheric);

c) the secondary pressure-holding period.

Each holding period shall not be less than 3 min, the timing of which shall not start until the external surfaces of the body members have been thoroughly dried, the test pressure has been reached, and the equipment and the pressure monitoring gauge have been isolated from the pressure source.

Annex I
(informative)

Procedure for the application of a coating system

I.1 General

This annex covers the application of a standard protective paint coating system for subsea equipment.

I.2 Purpose

The purpose of this protective coating procedure is to ensure the proper preparation of the material and proper application of the coating. There are a number of paint companies that manufacture high quality two part epoxy-polyamide or polyamine paints suitable to coat subsea equipment. This procedure describes how to apply this type of paint to the subsea equipment. This procedure describes only one of the many acceptable coating systems, and should be regarded as typical of how coating systems should be applied.

I.3 Surface preparation

I.3.1 Required finish

All surfaces to be coated shall be grit blasted to white metal finish in accordance with the following standards:

— NACE No. 2;

— SSPC-SP-10;

— ISO 8501-1.

I.3.2 Required cleanliness

Any oil and/or grease shall be removed with an appropriate solvent before priming.

I.3.3 Atmospheric conditions

Blast cleaning shall not be carried out on wet surfaces, nor shall blast cleaning be carried out when surfaces are less than 3 °C (5 °F) above dew point.

I.3.4 Air supply

The compressed air supply used for blasting shall be supplied at a minimum pressure of 0,5 MPa (70 psi) free of water and oil.

I.3.5 Use of chemicals

No acid washes or other cleaning solutions shall be used on metal surfaces after they have been blasted. This includes inhibited washes intended to prevent rusting.

I.3.6 *Surface laminations*

Surface laminations shall be ground out, and weld splatter shall be removed. Other surface irregularities including rough capping, undercut and slag together with sharp or rough edges, fins and burrs, shall be power wire brushed, ground, chipped or blasted as necessary to render the substrate suitable for coating.

I.3.7 Masking

Areas that will not be painted and that require protection shall be adequately masked.

I.3.8 Rust removal

If any rust forms after initial blasting, the rusted surfaces shall be reblasted and cleaned prior to priming.

I.4 Priming

I.4.1 Cleaning

All sand and dust shall be blown from the surfaces to be primed with dry, oil-free compressed air or nitrogen gas.

I.4.2 Application

The primer shall be applied with spray, preferably airless spray equipment.

I.4.3 Timing

Blast-cleaned surfaces shall be coated with the specified primer within 4 h after grit blasting.

I.4.4 Humidity

The primer shall be applied within the relative humidity specified by the paint manufacturer.

I.5 Coating systems

I.5.1 Typical coating materials

Primer - polyamide or polyamine or epoxy primer: 2,5/4,0 mils dry film thickness

Finish coat - polyamine glass flake epoxy: 12/20 mils dry film thickness

NOTE Alternative coatings may be used providing any products do not contain heavy metals such as lead, chrome, etc.

I.5.2 Drying times

Drying times between coats shall be strictly in accordance with the paint manufacturer's instructions.

I.5.3 Instructions preparation/application

All coatings shall be mixed, thinned and applied in accordance with the manufacturer's instructions.

I.5.4 Legislative requirements

All products used shall meet any applicable legislation in the country of manufacture and country where used with regard to volatile organic compounds.

I.5.5 Finish coat colour

Finish coat colour for subsea equipment shall meet the requirements of ISO 13628-1.

I.6 Touch up of coating system

All touch up coatings shall be the same manufacturer's materials as the original coatings. Where sandblasting is impractical, power wire brush to remove all oxidation will be acceptable. 150 mm (6 in) around the damaged area may also be wire brushed or lightly sanded by hand to roughen the epoxy to promote adhesion.

I.6.1 Repair of coating damage down to metal

Clean area with solvent to remove all oil and grease, wire brush if shiny. If the manufacturer supplies a solvent that will assist in repair, apply the solvent to the coated areas adjacent to the damaged area. When the adjacent coating becomes tacky, apply the coating system described in J.5.1.

I.6.2 Repair of epoxy coating damage not extending to metal

Sandpaper and feather out area to be repaired. Clean off with dry oil-free compressed air or nitrogen gas. Apply the high solid epoxy coatings as necessary to achieve the original finish.

I.7 Inspection

I.7.1 Coating thickness

A calibrated paint film thickness device shall be used to measure the dry film thickness at each stage of the painting process.

I.7.2 Correcting coating thickness

When dry film thicknesses are less than those specified, additional coatings shall be applied as necessary to achieve specified thickness.

I.7.3 Coating defects

All coatings shall be free of pin holes, voids, bubbles and other holidays.

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Annex ZA (normative)
Normative references to international publications with their relevant European publications

This European Standard incorporates by dated or undated reference, provisions from other publications. These normative references are cited at the appropriate places in the text and the publications are listed hereafter. For dated references, subsequent amendments to or revisions of any of these publications apply to this European Standard only when incorporated in it by amendment or revision. For undated references the latest edition of the publication referred to applies.

Publication	Year	Title	EN	Year
ISO 11960	1996	Petroleum and natural gas industries - Steel pipes for use as casing or tubing for wells	EN ISO 11960	1998
ISO 13628-1	1999	Petroleum and natural gas industries - Design and operation of subsea production systems - Part 1: General requirements and recommendations	EN ISO 13628-1	1999

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