

DIN EN ISO 13628-4

ICS 75.180.10

Ersatz für
DIN EN ISO 13628-4:2011-04

**Erdöl- und Erdgasindustrie –
Auslegung und Betrieb von Unterwasser-Produktionssystemen –
Teil 4: Bohrloch- und E-Kreuz-Ausrüstungen für den Unterwassereinsatz
(ISO 13628-4:2010 + Cor. 1:2011);
Englische Fassung EN ISO 13628-4:2010 + AC:2011, nur auf CD-ROM**

Petroleum and natural gas industries –
Design and operation of subsea production systems –
Part 4: Subsea wellhead and tree equipment (ISO 13628-4:2010 + Cor. 1:2011);
English version EN ISO 13628-4:2010 + AC:2011, only on CD-ROM

Industries du pétrole et du gaz naturel –
Conception et exploitation des systèmes de production immergés –
Partie 4: Équipements immergés de tête de puits et tête de production
(ISO 13628-4:2010 + Cor. 1:2011);
Version anglaise EN ISO 13628-4:2010 + AC:2011, seulement en CD-ROM

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Normenausschuss Erdöl- und Erdgasgewinnung (NÖG) im DIN

Nationales Vorwort

Dieses Dokument (EN ISO 13628-4:2010 + AC:2011) wurde vom Technischen Komitee ISO/TC 67 „Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries“ in Zusammenarbeit mit dem Technischen Komitee CEN/TC 12 „Materialien, Ausrüstungen und Offshore-Bauwerke für die Erdöl-, petrochemische und Erdgasindustrie“ (Sekretariat: AFNOR, Frankreich) erarbeitet.

Das zuständige deutsche Gremium ist der Arbeitskreis NA 109-00-01-04 AK „Bohr- und Fördereinrichtungen – Spiegelausschuss zu ISO/TC 67/SC 4“ im Normenausschuss Erdöl- und Erdgasgewinnung (NÖG) im DIN Deutsches Institut für Normung e. V.

Dieses Dokument enthält unter Berücksichtigung des DIN-Präsidialbeschlusses 1/2004 nur die englische Originalfassung der ISO Norm.

Dieses Dokument enthält neben den gesetzlichen Einheiten auch die Einheiten „°F“, „bbl“, „ft“, „in (inch)“, „lb (pound)“, „lbf“, „ppm“ und „psi (psig)“, die in Deutschland nicht zugelassen sind. Es wird ausdrücklich darauf hingewiesen, dass die Anwendung dieser Einheiten im nationalen amtlichen und geschäftlichen Verkehr aufgrund des Gesetzes über Einheiten im Messwesen nicht zulässig ist.

Umrechnung:

Nicht-SI-Einheit	SI-Einheit	Umrechnung	
°F	°C	°C	= (5/9) (°F-32)
bbl	dm ³	1 bbl	= 158,987 dm ³
ft	m	1 ft	= 0,304 8 m
in (inch)	mm	1 inch	= 25,4 mm
lb (pound)	kg	1 lb	= 0,453 592 37 kg
lbf	N	1 lbf	= 4,448 222 N
ppm	mg/kg	1 ppm	= 1 mg/kg
psi (psig)	kPa	1 psi	= 6,894 757 kPa

ISO 13628, *Petroleum and natural gas industries — Design and operation of subsea production systems* besteht aus den folgenden Teilen:

- *Part 1: General requirements and recommendations*
- *Part 2: Unbonded flexible pipe systems for subsea and marine applications*
- *Part 3: Through flowline (TFL) systems*
- *Part 4: Subsea wellhead and tree equipment*
- *Part 5: Subsea umbilicals*
- *Part 6: Subsea production control systems*

- *Part 7: Completion/workover riser systems*
- *Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems*
- *Part 9: Remotely Operated Tool (ROT) intervention systems*
- *Part 10: Specification for bonded flexible pipe*
- *Part 11: Flexible pipe systems for subsea and marine applications*
- *Part 15: Subsea structures and manifolds*
- *Part 16: Specification for flexible pipe ancillary equipment*
- *Part 17: Specification for flexible pipe ancillary equipment*

Für die in diesem Dokument zitierten Internationalen Normen wird im Folgenden auf die entsprechenden Deutschen Normen hingewiesen:

ISO 8501-1	siehe	DIN EN ISO 8501-1
ISO 10423	siehe	DIN EN ISO 10423
ISO 10424-1	siehe	DIN EN ISO 10424-1
ISO 11960	siehe	DIN EN ISO 11960
ISO 13625	siehe	DIN EN ISO 13625
ISO 13628-1	siehe	DIN EN ISO 13628-1
ISO 13628-3	siehe	DIN EN ISO 13628-3
ISO 13628-7	siehe	DIN EN ISO 13628-7
ISO 13628-8	siehe	DIN EN ISO 13628-8
ISO 13628-9	siehe	DIN EN ISO 13628-9
ISO 13533	siehe	DIN EN ISO 13533
ISO 15156 (all parts)	siehe	DIN EN ISO 15156 (alle Teile)

Änderungen

Gegenüber DIN EN ISO 13628-4:1999-10 wurden folgende Änderungen vorgenommen:

- a) Aktualisierung der Normativen Verweisungen;
- b) Erweiterung der Begriffsdefinitionen, z. B. „corrosion-resistant material“;
- c) Erweiterung der „Component“ in Tabelle 3 „Minimum validation test requirements“;
- d) Erweiterung des Abschnitts 5.3.3 „Corrosion-resistant overlays“;
- e) neues Bild 2 „Example of vertical trees on tubing heads“;

- f) neues Bild 4 a) „Examples of bore penetrations, Production bore penetrations“;
- g) neues Bild 4 b) „Examples of bore penetrations, Abbulus bore penetrations“;
- h) neue Tabelle 4 „Pressure test pictorial representations“;
- i) neues Bild 9 „Tree guide frames“;
- j) neues Bild 11 „External loads on a subsea tree and wellhead“;
- k) neues Bild A.3 „Guidelineless style vertical tree“;
- l) neues Bild B.1 „Guideline style horizontal tree“ und Bild B.2 „Guidelineless style horizontal tree“;
- m) neues Bild D.3 „Tubing hanger for horizontal tree“ und Bild D.4 „Extended tubing hanger for horizontal tree“;
- n) neues Bild E.2 „Mudline conversation equipment“;
- o) neuer informativer Anhang G „Assembly guideline of ISO (API) bolted flanged connections“;
- p) neuer informativer Anhang J „Screening tests for material compatibility“;
- q) neuer informativer Anhang K „Desgin and testing of pad eyes for lifting“;
- r) neuer informativer Anhang L „Hyperbaric testing guidelines“;
- s) neuer infomativer Anhang M „Purchasing guidelines“;
- t) Aktualisierung der Literaturhinweise.

Gegenüber DIN EN ISO 13628-4:2011-04 wurden folgende Änderungen vorgenommen:

- u) In Tabelle 11 "Hub and bore dimensions for type 17SV flanges for 34,5 MPa (5 000 psi) rated working pressure" ist im Bild das Winkelmass geändert;
- v) Die Zeichnungsqualität von Bild A.3 "Guidelines style vertical tree" wurde verbessert;
- w) In K.3.3.3.5 wurde die Darstellungsqualität der Gleichung K.25 verbessert, sowie die darin enthaltende Berechnung des "unit moment of inertia of weld" korrigiert.

Frühere Ausgaben

DIN EN ISO 13628-4: 1999-10, 2011-04

Nationaler Anhang NA (informativ)

Begriffe, Symbole und Abkürzungen

Die Benennung der folgenden Begriffe, Symbole und Abkürzungen sind identisch mit der Benennung in der englischen Fassung.

3 Begriffe, Abkürzungen und Symbole

3.1 Begriffe

Für die Anwendung dieses Dokuments gelten die folgenden Begriffe.

3.1.1

Ringraumabdichtungs-Garnitur

Mechanismus, der eine druckdichte Abrennung zwischen Futterrohrhänger und Bohrlochkopf-Gehäuse ermöglicht

3.1.2

Backdriving

Rücklauf

⟨allgemein⟩ ungeplante Bewegung in der einer Funktion entgegengesetzten Richtung

3.1.3

Backdriving

Rücklauf

⟨Hubantrieb⟩ Zustand, in dem das Ventil aus der eingestellten Stellung abdriftet

3.1.4

Backdriving

Rücklauf

⟨handbetätigte/durch ROV betätigte Drosseleinrichtung⟩ Zustand, in dem das Ventil seine Stellung ändert, nachdem der Antrieb entriegelt wurde

3.1.5

Backdriving

Rücklauf

⟨Drehantrieb⟩ Zustand, in dem das Ventil nach Abschluss einer Stellungsänderungsbewegung weiterhin seine Stellung ändert

3.1.6

Backdriving

Rücklauf

⟨durch einen Schrittmotor angetriebene Drosseleinrichtung⟩ Zustand, in dem das Ventil seine Stellung ändert, nachdem der Antrieb entriegelt wurde

3.1.7

Bohrungsschutzeinrichtung

Einrichtung zum Schutz der Innenflächen des Bohrlochs während der Bohr- oder Aufwältigungsarbeiten

3.1.8

Rückschlagventil

Armatur, die den Durchfluss in nur einer Richtung gestattet

3.1.9

Drosseleinrichtung

Ausrüstung, mit der der Fluss von Fluiden und Gas eingeschränkt und gesteuert wird

3.1.10

Komplettierungs-/Aufwältigungs-Riser

Verlängerung der Förder- und/oder Ringraumborung(en) eines Unterwasser-Bohrlochs bis zum Installations-schiff an der Oberfläche

Siehe ISO 13628-7.

3.1.11

Standrohr-Gehäuse

oberer Abschnitt des ersten Futterrohrstranges, der den Unterbau für den Unterwasser-Bohrlochkopf bildet und Befestigungen für die Führungskonstruktionen bietet

3.1.12

Korrosionsschutzkappe

auf dem Bohrlochkopf während des zeitweiligen Aufgebens des Bohrlochs zum Schutz gegen Verunreinigung durch Verschlammung, marinen Bewuchs oder Korrosion angebrachte Abdeckung

3.1.13

korrosionsbeständige Legierung

CRA

Nichteisenlegierung, bei der die für jedes einzelne oder für die Summe der folgenden Legierungselemente festgelegte Menge mehr als 50 % beträgt: Titan, Nickel, Kobalt, Chrom und Molybdän

ANMERKUNG Dieser Begriff bezieht sich auf korrosionsbeständige Legierungen und nicht auf die in ISO 15156 (alle Teile) erwähnten rissbildungsbeständigen Legierungen.

3.1.14

korrosionsbeständiger Werkstoff

CRM

Eisen- oder Nichteisenlegierung, die korrosionsbeständiger ist als niedriglegierte Stähle

ANMERKUNG Dieser Begriff umfasst CRAs, Duplexstähle und nichtrostende Stähle.

3.1.15

Tiefenbemessung

maximale Nennarbeitstiefe eines Ausrüstungsteils unter einer bestimmten Reihe von Betriebsbedingungen

3.1.16

nachgeschaltet

Bewegungsrichtung weg von der Lagerstätte

3.1.17

Ausrüstung

jedes Bauteil oder jede Baugruppe, für die diese Internationale Norm gilt

3.1.18

Extension Sub (Verlängerungsrohr)

Rohrstück, das zwischen E-Kreuz und benachbarten Teilen des E-Kreuzes eine kontinuierliche und druck-dichte Verbindung ermöglicht

3.1.19**in Störfällen schließendes Ventil**

Ventil, das so konstruiert ist, dass es bei Störungen automatisch schließt

3.1.20**in Störfällen öffnendes Ventil**

Ventil, das so konstruiert ist, dass es bei Störungen automatisch öffnet

3.1.21**Förderleitung**

jede Rohrleitung, die an die Unterwasser-E-Kreuz-Baugruppe außerhalb des Förderleitungs-Verbindungsstücks oder Klemmenkragens anschließt

3.1.22**Stützrahmen für das Förderleitungs-Verbindungsstück**

Tragrahmen, der das Verbindungsstück der Förderleitung aufnimmt und abstützt und die Lasten von der Förderleitung zurück in den Bohrlochkopf oder in die auf dem Meeresboden verankerte Konstruktion überträgt

3.1.23**Förderleitungs-Verbindungssystem**

Einrichtung zur Anbringung der Unterwasser-Rohrleitungen und/oder Steuer-Versorgungskabel an einem Unterwasser-E-Kreuz

BEISPIEL Am E-Kreuz befestigte Verbindungssysteme zur direkten Verbindung einer Unterwasser-Förderleitung mit einem Unterwasser-E-Kreuz, zur Verbindung eines Förderleitungs-Endanschlusses mit einem Unterwasser-E-Kreuz über eine Überbrückung, zur Verbindung eines Unterwasser-E-Kreuzes mit einem Manifold über eine Überbrückung usw..

3.1.24**Flow Loop**

Rohrleitung, die den Auslass/die Auslässe des Unterwasser-E-Kreuzes mit dem Verbindungsstück der Unterwasser-Förderleitung und/oder mit anderen Anschlüssen der E-Kreuz-Verrohrung (Querverbindungsrohre usw.) verbindet

3.1.25**Führungstrichter**

konische Erweiterung am Ende eines Führungselementes, die zur primären Führung eines anderen Führungselementes vorgesehen ist

3.1.26**Führungsseil**

Spannseil vom Meeresboden bis zur Oberfläche zu dem Zweck, Ausrüstungen zu den Konstruktionen auf dem Meeresboden zu führen

3.1.27**Hochdruck-Riser**

Rohrstück zur Verlängerung des Bohrlochs vom Mudline-Bohrlochkopf oder Steigrohrkopf bis zum Oberflächen-BOP

3.1.28**horizontales E-Kreuz**

E-Kreuz, dessen Produktions-Hauptschieber nicht im vertikalen Bohrloch, sondern in den horizontalen Auslässen zur Seite angeordnet ist

3.1.29**hydraulischer Nennbetriebsdruck**

größter Innendruck, für dessen Aufnahme und/oder Regelung die hydraulische Ausrüstung ausgelegt ist

ANMERKUNG Der hydraulische Druck sollte nicht mit dem hydraulischen Prüfdruck verwechselt werden.

3.1.30

hydrostatischer Druck

größter Außendruck der Meeresumgebung (maximale Wassertiefe), den die Ausrüstung aufnehmen und/oder steuern kann

3.31

Haltevorrichtung für Eingriffe

an der Unterwasser-Bohrlochausrüstung dauerhaft angebrachte Vorrichtung oder Einrichtung zur Erleichterung von unter Wasser auszuführenden Eingriffen, die Folgendes umfasst, jedoch nicht allein darauf beschränkt ist:

- greifende Haltevorrichtungen für Eingriffe;
- andockende Haltevorrichtungen für Eingriffe;
- landende Haltevorrichtungen für Eingriffe;
- mit Belastung und Zug arbeitende Haltevorrichtungen für Eingriffe;
- durch Drehen aktivierte Haltevorrichtungen für Eingriffe;
- hydraulisch aktivierte Haltevorrichtungen für Eingriffe.

3.1.32

Eingriffssystem

Mittel zur Ausbringung und Beförderung von Eingriffswerkzeugen zur Unterwasser-Bohrlochausrüstung, damit folgende Eingriffe durchgeführt werden können:

- Fernlenkung von Fahrzeugen (ROV);
- Fernbetätigung von Werkzeugen (ROT);
- Anwendung von Tauchsyste men unter atmosphärischem Druck (ADS);
- Einsatz von Tauchern.

3.1.33

Eingriffswerkzeug

Einrichtung oder ROT, die mit einem Eingriffssystem so ausgebracht wird, dass sie an eine Haltevorrichtung für Eingriffe angeschlossen oder angekoppelt werden kann

3.1.34

Hebe-Augplatte

Augplatte zum Heben und zur Aufhängung einer Bemessungslast oder einer Block-Garnitur

3.1.35

untere Abdichtung des Aufwältigungs-Risers (LWRP)

Block-Garnitur, die an die obere Verbindung des E-Kreuzes angekoppelt wird und die Abdichtung der vertikalen Bohrung(en) des E-Kreuzes ermöglicht

3.1.36

Mudline-Aufhängungsvorrichtung

Bohrsystem, das aus mehreren Gehäusen zur Aufnahme der Futterrohrstränge an der Mudline (Spülungsleitung) besteht und von einer auf dem Meeresboden aufgesetzten Bohrin sel unter Verwendung eines Oberflächen-BOP installiert wird

3.1.37**Richthülsen**

nicht drucktragende Teile zur Ausrichtung von Ausrüstung oder Werkzeugen in Bezug auf den Bohrlochkopf

3.1.38**externe E-Kreuz-Verrohrung**

dem letzten Ventil des E-Kreuzes (einschließlich Drosselbaugruppe) nachgeschaltete und dem Förderleitungs-Verbindungsstück vorgeschaltete Rohrleitung des Unterwasser-E-Kreuzes

Siehe Flow Loop (3.1.24).

3.1.39**stationäre Führung**

Konstruktion, die die Ausfluchtung und Ausrichtung in Bezug auf das Bohrlochkopfsystem festlegt und eine Führung für die Einbau-Ausrüstungen an der oder in die Bohrlochkopf-Baugruppe ermöglicht

3.1.40**drucktragendes Teil**

Teil, dessen Versagen, so wie vorgesehen zu funktionieren, dazu führt, dass das im Bohrloch enthaltene Fluid in die Umgebung freigesetzt wird

BEISPIELE Gehäuse, Hauben, Spindeln.

3.1.41**drucksteuerndes Teil**

Teil, das zur Steuerung oder Regelung der Bewegung von unter Druck stehenden Fluiden vorgesehen ist

BEISPIEL Abdichtungsmechanismen von Ventildurchgängen, Drosselventileinsatz und Hänger.

3.1.42**Nennbetriebsdruck****RWP**

größter Innendruck, für dessen Aufnahme und/oder Steuerung die Ausrüstung ausgelegt ist

ANMERKUNG Der Nennbetriebsdruck sollte nicht mit dem Prüfdruck verwechselt werden.

3.1.43**Re-Entry-Spool**

Profil der oberen Verbindung des E-Kreuzes, das eine fernbetätigte Verbindung mit einem E-Kreuz-Einbauwerkzeug, einer LWRP oder einer Schutzkappe für das E-Kreuz ermöglicht

3.1.44**Differenzdruck in entgegengesetzter Richtung**

Zustand, in dem der Differenzdruck auf ein Drosselventil in der zur festgelegten Betriebsrichtung entgegengesetzten Richtung aufgebracht wird

ANMERKUNG Das kann in der Betriebsstellung oder in der Stellung bei geschlossenem Drosselventil erfolgen.

3.1.45**Einbauwerkzeug**

Werkzeug, das von der Oberfläche aus zum Einbau, Ausbau, Positionieren oder zur Verbindung von Unterwasserausrüstungen verwendet wird

BEISPIELE Einbauwerkzeuge für das E-Kreuz, für die Schutzkappe des E-Kreuzes, für das Förderleitungs-Verbindungsstück usw.

3.1.46

Unterwasser-BOP

für den Einsatz an Unterwasser-Bohrlochköpfen, -Steigrohrhängern oder -E-Kreuzen konstruierter Blowout-Preventer

3.1.47

Futterrohr-Hänger für den Unterwassereinsatz

Einrichtung, die im Bohrlochkopf an der Spülungsleitung einen Futterrohrstrang trägt

3.1.48

Unterwasser-Komplettierungsausrüstung

spezielle E-Kreuz- und Bohrlochkopf-Ausrüstung, die zur Komplettierung eines Bohrlochs unter Wasser verwendet wird

3.1.49

Unterwasser-Bohrlochkopfgehäuse

drucktragendes Gehäuse, das eine Möglichkeit zum Abhängen und Abdichten der Futterrohrstränge im Bohrloch bietet

3.1.50

Unterwasser-Drahtseil-/Coiled-Tubing-BOP

zur Erleichterung von Eingriffen mithilfe von Drahtseilen oder Coiled tubing (gewickelten Rohrsträngen) an der Oberseite eines Unterwasser-E-Kreuzes angebrachter Unterwasser-BOP

3.1.51

Oberflächen-BOP

für den Einsatz auf einer Anlage an der Oberfläche, wie z. B. einer ortsfesten Plattform, Hubinsel oder schwimmenden Bohreinheit ausgelegter Blowout-Preventer

3.1.52

Drehkopfflansch

Flansch-Baugruppe, die aus einem zentral angeordneten Ansatz und einer separaten Ringführung besteht, die um den Ansatz frei drehbar ist

ANMERKUNG Drehkopfflansche vom Typ 17SV können mit den genormten ISO-Flanschen 17SS und 6BX verwendet werden, die gleich groß und für den gleichen Nenndruck ausgelegt sind.

3.1.53

Tieback-Adapter

Vorrichtung, die die Schnittstelle zwischen der Mudline-Aufhängungsvorrichtung und der Unterwasser-Komplettierungsausrüstung bildet

3.1.54

Schutzkappe für das E-Kreuz

drucktragende Abdeckung zum Schutz der Umgebung, die in einem vertikalen E-Kreuz oberhalb der Produktions-Servicearmatur und in einem horizontalen E-Kreuz oberhalb des Steigrohrhängers installiert ist

3.1.55

E-Kreuz-Verbindungsstück

Mechanismus, der die Verbindung und Abdichtung zwischen einem Unterwasser-E-Kreuz und einem Unterwasser-Bohrlochkopf oder -Steigrohrkopf herstellt

3.1.56

Führungsrahmen für das E-Kreuz

Tragrahmen, der zur Führung, Ausrichtung und zum Schutz des Unterwasser-E-Kreuzes am Unterwasser-Bohrlochkopf/-Steigrohrkopf verwendet werden kann und außerdem E-Kreuz-Förderleitungen und -Verbindungssteile, Steuermodule, Anoden und Ausgleichsmassen stützt

3.1.57**seitlicher Auslass des E-Kreuzes**

Stelle, an der am E-Kreuz-Block seitlich eine Bohrung vorhanden ist

3.1.58**Versorgungskabel**

Schlauch, Steigrohr, Rohrleitung und/oder elektrischer Leiter, der/die/das Fluide und/oder elektrischen Strom oder Signale zu oder von den Unterwasser-E-Kreuzen leitet

3.1.59**vorgeschaltet**

Bewegungsrichtung hin zur Lagerstätte

3.1.60**Ventilblock**

integraler Block, der ein oder mehrere Ventil(e) enthält

3.1.61**vertikales E-Kreuz**

E-Kreuz, dessen Hauptschieber im vertikalen Bohrloch des E-Kreuzes unterhalb des seitlichen Auslasses angeordnet ist

3.1.62**Verschleißeinsatz**

Bohrlochschutz, der auch den darunter gelegenen Futterrohrhänger schützt

3.1.63**Druckabgrenzungsbereich am Bohrlochkopf-Gehäuse**

Bohrlochkopf-Gehäuse von der Oberseite des Bohrlochkopfes bis zu den untersten Dichtungen

3.1.64**Wye-Spool**

Schieber zwischen dem Hauptschieber und den Service-Armaturen eines TFL-Eruptionskreuzes, der den Durchgang der TFL-Werkzeuge von den Förderleitungen in die Bohrungen des E-Kreuzes ermöglicht

3.2 Abkürzungen und Symbole

ADS	Tauchsystem unter atmosphärischem Druck
AMV	Ringraum-Hauptschieber
ANSI	American National Standards Institute (amerikanisches Normungsinstitut)
API	American Petroleum Institute (amerikanisches Erdölinstitut)
ASME	American Society of Mechanical Engineers (Amerikanische Gesellschaft der Maschinenbauingenieure)
ASV	Ringraum-Servicearmatur
AWS	American Welding Society (Amerikanische Gesellschaft für Schweißtechnik)
AWV	Ringraum-Seitenschieber
BOP	Blowout-Preventer
CGB	Komplettierungs-Führungssockel
CID	chemische Injektion – im Bohrloch
CIT	chemische Injektion – E-Kreuz
CRA	korrosionsbeständige Legierung
CRM	korrosionsbeständiger Werkstoff
EDP	Notfall-Trenn-Vorrichtung (siehe ISO 13628-7)
FAT	Werksabnahmeprüfung
FEA	Finite-Elemente-Analyse
GRA	Einrichtung zum kabellosen Wiedereinführen
HXT	horizontales Unterwasser-E-Kreuz
ID	Innendurchmesser
LRP	untere Riser-Abdichtung (siehe ISO 13628-7)
LWRP	untere Aufwältigungs-Riser-Abdichtung (LRP + EDP) (siehe ISO 13268-7)
NACE	National Association of Corrosion Engineers (Nationale Vereinigung der Korrosionsingenieure in den USA)
NDE	zerstörungsfreie Prüfung
OD	Außendurchmesser
OEC	sonstige Anschlüsse
PGB	stationäre Führung
PMR	nach Herstellervorgabe
PMV	Produktions-Hauptschieber
PR2	Leistungsanforderung der Stufe Zwei
PSL	Stufe der Produktspezifikation
PSV	Produktions-Servicearmatur
PWV	Produktions-Seitenschieber
QTC	Qualifikationsprobe
RMS	quadratisches Mittel

ROT	fernbetätigtes Werkzeug (siehe ISO 13268-9)
ROV	ferngelenktes Fahrzeug (siehe ISO 13268-8)
RWP	Nennbetriebsdruck
S_b	Biegespannung
S_m	Membranspannung
S_Y	Fließspannung
SCSSV	übertage gesteuertes Untertage-Sicherheitsventil
SCF	Spannungskonzentrationsfaktor
SIT	Systemintegrationsprüfung
SWL	sichere Betriebslast
TFL	durch die Förderleitung (durchgeführte Verfahren) (siehe ISO 13628-3)
TGB	zeitweilige Führung
USV	Unterwasser-Sicherheitsventil (siehe ISO 10423)
VXT	vertikales E-Kreuz
WCT-BOP	Drahtseil-/Coiled-Tubing-Blowout-Preventer (siehe ISO 13628-7)
XOV	Übergangsventil
XT	Eruptions-Kreuz

Nationaler Anhang NB (informativ)

Literaturhinweise

DIN EN ISO 8501-1, *Vorbereitung von Stahloberflächen vor dem Auftragen von Beschichtungsstoffen — Visuelle Beurteilung der Oberflächenreinheit — Teil 1: Rostgrade und Oberflächenvorbereitungsgrade von unbeschichteten Stahloberflächen und Stahloberflächen nach ganzflächigem Entfernen vorhandener Beschichtungen*

DIN EN ISO 10423, *Erdöl- und Erdgasindustrie — Bohr- und Förderausrüstung — Bohrlochkopf- und Eruptionskreuz-Ausrüstung*

DIN EN ISO 10424-1, *Erdöl- und Erdgasindustrie — Drehende Bohrausrüstungsteile — Teil 1: Drehende Bohrgestänge-Elemente*

DIN EN ISO 11960, *Erdöl- und Erdgasindustrie — Stahlrohre zur Verwendung als Futter- oder Steigrohre für Bohrungen*

DIN EN ISO 13625, *Erdöl- und Erdgasindustrie — Bohr- und Förderausrüstungen — Kupplungen für Bohrförderleitungen auf See*

DIN EN ISO 13628-1, *Erdöl- und Erdgasindustrie — Auslegung und Betrieb von Unterwasser-Produkitionssystemen — Teil 1: Allgemeine Anforderungen und Empfehlungen*

DIN EN ISO 13628-3, *Erdöl- und Erdgasindustrie — Konstruktion und Betrieb von Unterwasser-Produkitionssystemen — Teil 3: Through-flowline (TFL)-Pumpsysteme*

DIN EN ISO 13628-7, *Erdöl- und Erdgasindustrie — Auslegung und Betrieb von Unterwasser-Produkitionssystemen — Teil 7: Komplettierungs-/Aufwältigungs-Risersysteme*

DIN EN ISO 13628-8, *Erdöl- und Erdgasindustrie — Auslegung und Betrieb von Unterwasser-Produkitionssystemen — Teil 8: Schnittstellen mit ferngelenkten Transporteinheiten (ROV) auf Unterwasser-Produkitionssystemen*

DIN EN ISO 13628-9, *Erdöl- und Erdgasindustrie — Auslegung und Betrieb von Unterwasser-Produkitionssystemen — Teil 9: ROT-Systeme*

DIN EN ISO 13533, *Erdöl- und Erdgasindustrie — Bohr- und Fördereinrichtungen — Drill-through equipment*

DIN EN ISO 15156-1, *Erdöl- und Erdgasindustrie — Werkstoffe für den Einsatz in H₂S-haltiger Umgebung bei der Öl- und Gasgewinnung — Teil 1: Allgemeine Grundlagen für die Auswahl von gegen Rissbildung beständigen Werkstoffen*

DIN EN ISO 15156-2, *Erdöl- und Erdgasindustrie — Werkstoffe für den Einsatz in H₂S-haltiger Umgebung bei der Öl- und Gasgewinnung — Teil 2: Gegen Rissbildung beständige unlegierte und niedriglegierte Stähle und Gusseisen*

DIN EN ISO 15156-3, *Erdöl- und Erdgasindustrie — Werkstoffe für den Einsatz in H₂S-haltiger Umgebung bei der Öl- und Gasgewinnung — Teil 3: Hochlegierte Stähle (CRAs) und andere Legierungen*

English Version

Petroleum and natural gas industries –
Design and operation of subsea production systems –
Part 4: Subsea wellhead and tree equipment
(ISO 13628-4:2010 + Cor. 1)

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
(ISO 13628-4:2010 + Cor. 1)

Erdöl- und Erdgasindustrie –
Auslegung und Betrieb von Unterwasser-
Produktionssystemen –
Teil 4: Bohrloch- und E-Kreuz-Ausrüstungen
für den Unterwassereinsatz
(ISO 13628-4:2010 + Cor. 1)

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Foreword

This document (EN ISO 13628-4:2010) has been prepared by Technical Committee ISO/TC 67 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” in collaboration with Technical Committee CEN/TC 12 “Materials, equipment and offshore structures for petroleum, petrochemical 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 June 2011, and conflicting national standards shall be withdrawn at the latest by June 2011.

Attention is drawn to the possibility that some of the elements of this document may be the subject of patent rights. CEN [and/or CENELEC] shall not be held responsible for identifying any or all such patent rights.

This document supersedes EN ISO 13628-4:1999.

According to the CEN/CENELEC Internal Regulations, the national standards organizations of the following countries are bound to implement this European Standard: Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

Endorsement notice

The text of ISO 13628-4:2010 has been approved by CEN as a EN ISO 13628-4:2010 without any modification.

Foreword of AC

This document (EN ISO 13628-4:2010/AC:2011) has been prepared by Technical Committee ISO/TC 67 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” in collaboration with Technical Committee CEN/TC 12 “Materials, equipment and offshore structures for petroleum, petrochemical and natural gas industries” the secretariat of which is held by AFNOR.

Endorsement notice

The text of ISO 13628-4:2010/Cor 1:2011 has been approved by CEN as a EN ISO 13628-4:2010/AC:2011 without any modification.

Introduction

This second edition of ISO 13628-4 has been updated by users and manufacturers of subsea wellheads and trees. Particular attention was paid to making it an auditable standard. It is intended for worldwide application in the petroleum industry. It is not intended to replace sound engineering judgement. It is necessary that users of this part of ISO 13628 be aware that additional or different requirements can better suit the demands of a particular service environment, the regulations of a jurisdictional authority or other scenarios not specifically addressed.

A major effort in developing this second edition was a study of the risks and benefits of penetrations in subsea wellheads. All previous editions of both this part of ISO 13628 and its parallel API document *Specification for Subsea Wellhead and Christmas Tree Equipment* (Specification 17D) prohibited wellhead penetrations. However, that prohibition was axiomatic. In developing this second edition, the workgroup used qualitative risk analysis techniques and found that the original insight was correct: subsea wellheads with penetrations are more than twice as likely to develop leaks over their life as those without penetrations.

The catalyst for examining this portion of the original editions of the API and ISO standards was the phenomenon of casing pressure and its monitoring in subsea wells. The report generated by the aforementioned risk analysis has become API 17 TR3 and API RP 90. The workgroup encourages the use of these documents when developing designs and operating practices for subsea wells.

Care has also been taken to address the evolving issue of using external hydrostatic pressure in design. The original versions of both API 17D and ISO 13628-4 were adopted at a time when the effects of that parameter were relatively small. The industry's move into greater water depths has prompted a consideration of that aspect in this version of this part of ISO 13628. The high-level view is that it is not appropriate to use external hydrostatic pressure to augment the applications for which a component can be used. For example, this part of ISO 13628 does not allow the use of a subsea tree rated for 69 MPa (10 000 psi) installed in 2 438 m (8 000 ft) of water on a well that has a shut-in tubing pressure greater than 69 MPa (10 000 psi). See 5.1.2.1.1 for further guidance.

The design considerations involved in using external hydrostatic pressure are only currently becoming fully understood. If a user or fabricator desires to explore these possibilities, it is recommended that a thorough review of the forthcoming American Petroleum Institute technical bulletin on the topic be carefully studied.

The overall objective of this part of ISO 13628 is to define clear and unambiguous requirements that facilitate international standardization in order to enable safe and economic development of offshore oil and gas fields by the use of subsea wellhead and tree equipment. It is written in a manner that allows the use of a wide variety of technology, from well established to state-of-the-art. The contributors to this update do not wish to restrict or deter the development of new technology. However, the user of this part of ISO 13628 is encouraged to closely examine standard interfaces and the reuse of intervention systems and tools in the interests of minimizing life-cycle costs and increasing reliability through the use of proven interfaces.

It is important that users of this part of ISO 13628 be aware that further or differing requirements can be needed for individual applications. This part of ISO 13628 is not intended to inhibit a vendor from offering, or the purchaser from accepting, alternative equipment or engineering solutions for the individual application. This can be particularly applicable where there is innovative or developing technology. Where an alternative is offered, it is the responsibility of the vendor to identify any variations from this part of ISO 13628 and provide details.

1 Scope

This part of ISO 13628 provides specifications for subsea wellheads, mudline wellheads, drill-through mudline wellheads and both vertical and horizontal subsea trees. It 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.

The user is responsible for ensuring subsea equipment meets any additional requirements of governmental regulations for the country in which it is installed. This is outside the scope of this part of ISO 13628.

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

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

a) subsea trees:

- tree connectors and tubing hangers,
- valves, valve blocks, and valve actuators,
- chokes and choke actuators,
- bleed, test and isolation valves,
- TFL wye spool,
- re-entry interface,
- tree cap,
- tree piping,
- tree guide frames,
- tree running tools,
- tree cap running tools,
- tree mounted flowline/umbilical connector,
- tubing heads and tubing head connectors,

- flowline bases and 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) mudline suspension systems:
- wellheads,
 - running tools,
 - casing hangers,
 - casing hanger running tool,
 - tieback tools for subsea completion,
 - subsea completion adaptors for mudline wellheads,
 - tubing heads,
 - 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,
 - guideline establishment equipment.

This part of ISO 13628 includes equipment definitions, an explanation of equipment use and function, an explanation of service conditions and product specification levels, and a description of critical components, i.e. those parts having requirements specified in this part of ISO 13628.

The following equipment is outside the scope of this part of ISO 13628:

- subsea wireline/coiled tubing BOPs;
- installation, workover, and production risers;
- subsea test trees (landing strings);
- control systems and control pods;
- platform tiebacks;
- primary protective structures;
- subsea process equipment;
- subsea manifolding and jumpers;
- subsea wellhead tools;
- repair and rework;
- multiple well template structures;
- mudline suspension high pressure risers;
- template piping;
- template interfaces.

This part of ISO 13628 is not applicable to the rework and repair of used equipment.

2 Normative references

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

ISO 8501-1, *Preparation of steel substrates before application of paints and related products — Visual assessment of surface cleanliness — Part 1: Rust grades and preparation grades of uncoated steel substrates and of steel substrates after overall removal of previous coatings*

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

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

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

ISO 13625, *Petroleum and natural gas industries — Drilling and production equipment — Marine drilling riser couplings*

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

ISO 13628-3, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 3: Through flowline (TFL) systems*

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

ISO 13628-8, *Petroleum and natural gas industries — Design and operation of subsea production systems — Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems*

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

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

ISO 15156 (all parts), *Petroleum and natural gas industries — Materials for use in H₂S-containing environments in oil and gas production*

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

ANSI/ASME B31.3, *Process Piping*

ANSI/ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*

ANSI/ASME B31.8, *Gas Transmission and Distribution Piping Systems*

ANSI/ISA 75.02, *Control Valve Capacity Test Procedure*

ANSI/SAE J517, *Hydraulic Hose Fittings*

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

API Spec 5B, *Specification for Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads (US Customary Units)*

ASTM D1414, *Standard Test Methods for Rubber O-Rings*

DNV RP B401, *Cathodic Protection Design*

ISA 75.01.01, *Flow Equations for Sizing Control Valves*

NACE No. 2/SSPC-SP 10, *Joint Surface Preparation Standard: Near-White Metal Blast Cleaning*

NACE SP0176, *Corrosion Control of Submerged Areas of Permanently Installed Steel Offshore Structures Associated With Petroleum Production*

SAE/AS 4059, *Aerospace Fluid Power — Cleanliness Classification for Hydraulic Fluids*

3 Terms, definitions, abbreviated terms and symbols

3.1 Terms and definitions

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

3.1.1

annulus seal assembly

mechanism that provides pressure isolation between each casing hanger and the wellhead housing

3.1.2

backdriving

⟨general⟩ an unplanned movement in the reverse direction of an operation

3.1.3

backdriving

⟨linear actuator⟩ condition where the valve drifts from the set position

3.1.4

backdriving

⟨manual/ROV operated choke⟩ condition where the valve changes position after the operator is disengaged

3.1.5

backdriving

⟨rotary actuator⟩ condition where the valve continues to change position subsequent to the completion of a positional movement

3.1.6

backdriving

⟨stepping-actuated choke⟩ condition where the valve changes position after the operator is disengaged

3.1.7

bore protector

device that protects internal bore surfaces during drilling or workover operations

3.1.8

check valve

device designed to prevent flow in one direction

3.1.9

choke

equipment used to restrict and control the flow of fluids and gas

3.1.10

completion/workover riser

extension of the production and/or annulus bore(s) of a subsea well to a surface vessel

See ISO 13628-7.

3.1.11

conductor housing

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

3.1.12

corrosion cap

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

3.1.13

corrosion-resistant alloy

CRA

non-ferrous alloy for which any one or the sum of the specified amount of the following alloy elements exceeds 50 %: titanium, nickel, cobalt, chromium and molybdenum

NOTE This term refers to corrosion-resistant alloys and not cracking-resistant alloys as mentioned in ISO 15156 (all parts).

3.1.14

corrosion-resistant material

CRM

ferrous or non-ferrous alloy that is more corrosion resistant than low-alloy steels

NOTE This term includes: CRAs, duplex, and stainless steels.

3.1.15

depth rating

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

3.1.16

downstream

direction of movement away from the reservoir

3.1.17

equipment

any item or assembly to which ISO 13628-4 is applicable

3.1.18

extension sub

sealing tubular member that provides tree-bore continuity between adjacent tree components

3.1.19

fail-closed valve

actuated valve designed to fail to the closed position

3.1.20

fail-open valve

actuated valve designed to fail to the open position

3.1.21

flowline

any pipeline connecting to the subsea tree assembly outboard the flowline connector or hub

3.1.22

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

3.1.23

flowline connector system

equipment used to attach subsea pipelines and/or control umbilicals to a subsea tree

EXAMPLE Tree-mounted connection systems used to connect a subsea flowline directly to a subsea tree, connect a flowline end termination to the subsea tree through a jumper, connect a subsea tree to a manifold through a jumper, etc.

3.1.24

flow loop

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

3.1.25

guide funnel

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

3.1.26

guideline

taut line from the seafloor to the surface for the purpose of guiding equipment to the seafloor structure

3.1.27

high-pressure riser

tubular member which extends the wellbore from the mudline wellhead or tubing head to a surface BOP

3.1.28

horizontal tree

tree that does not have a production master valve in the vertical bore but in the horizontal outlets to the side

3.1.29

hydraulic rated working pressure

maximum internal pressure that the hydraulic equipment is designed to contain and/or control

NOTE Hydraulic pressure should not be confused with hydraulic test pressure.

3.1.30

hydrostatic pressure

maximum external pressure of ambient ocean environment (maximum water depth) that equipment is designed to contain and/or control

3.1.31

intervention fixture

device or feature 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

3.1.32

intervention system

means to deploy or convey intervention tools to subsea well equipment to carry out intervention tasks, including

- ROV;
- ROT;
- ADS;
- Diver

3.1.33

intervention tool

device or ROT deployed by an intervention system to mate or interface with an intervention fixture

3.1.34

lifting pad eye

pad eye, intended for lifting and suspending a designed load or packaged assembly

3.1.35

lower workover riser package

LWRP

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

3.1.36

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

3.1.37

orienting bushings

non-pressure-containing parts that are used to orient equipment or tools with respect to the wellhead

3.1.38

outboard tree piping

subsea tree piping that is downstream of the last tree valve (including choke assemblies) and upstream of flowline connection

See **flow loop** (3.1.24).

3.1.39

permanent guidebase

structure that sets alignment and orientation relative to the wellhead system and provides entry guidance for running equipment on or into the wellhead assembly

3.1.40

pressure-containing part

part whose failure to function as intended results in a release of wellbore fluid to the environment

EXAMPLES Bodies, bonnets, stems.

3.1.41

pressure-controlling part

part intended to control or regulate the movement of pressurized fluids

EXAMPLE Valve-bore sealing mechanisms, choke trim and hangers.

3.1.42

rated working pressure

RWP

maximum internal pressure that equipment is designed to contain and/or control

NOTE Rated working pressure should not be confused with test pressure.

3.1.43

re-entry spool

tree upper connection profile, which allows remote connection of a tree running tool, LWRP or tree cap

3.1.44

reverse differential pressure

condition during which differential pressure is applied to a choke valve in a direction opposite to the specified operating direction

NOTE This can be in the operating or closed-choke position.

3.1.45

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.

3.1.46

subsea BOP

blowout preventer designed for use on subsea wellheads, tubing heads or trees

3.1.47

subsea casing hanger

device that supports a casing string in the wellhead at the mudline

3.1.48

subsea completion equipment

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

3.1.49

subsea wellhead housing

pressure-containing housing that provides a means for suspending and sealing the well casing strings

3.1.50

subsea wireline/coiled tubing BOP

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

3.1.51

surface BOP

blowout preventer designed for use on a surface facility such as a fixed platform, jackup or floating drilling or intervention unit

3.1.52

swivel flange

flange assembly consisting of a central hub and a separate flange rim that is free to rotate about the hub

NOTE Type 17SV swivel flanges can mate with standard ISO type 17SS and 6BX flanges of the same size and pressure rating.

3.1.53

tieback adapter

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

3.1.54

tree cap

pressure-containing environmental barrier installed above production swab valve in a vertical tree or tubing hanger in a horizontal tree

3.1.55

tree connector

mechanism to join and seal a subsea tree to a subsea wellhead or tubing head

3.1.56

tree guide frame

structural framework that may be used for guidance, orientation and protection of the subsea tree on the subsea wellhead/tubing head, and that also provides support for tree flowlines and connection equipment, control pods, anodes and counterbalance weights

3.1.57

tree-side outlet

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

3.1.58

umbilical

hose, tubing, piping, and/or electrical conductor that directs fluids and/or electrical current or signals to or from subsea trees

3.1.59

upstream

direction of movement towards the reservoir

3.1.60

valve block

integral block containing two or more valves

3.1.61

vertical tree

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

3.1.62

wear bushing

bore protector that also protects the casing hanger below it

3.1.63

wellhead housing pressure boundary

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

3.1.64

wye spool

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

3.2 Abbreviated terms and symbols

ADS	atmospheric diving system
AMV	annulus master valve
ANSI	American National Standards Institute
API	American Petroleum Institute

ASME	American Society of Mechanical Engineers
ASV	annulus swab valve
AWS	American Welding Society
AWV	annulus wing valve
BOP	blowout preventer
CGB	completion guidebase
CID	chemical injection – downhole
CIT	chemical injection – tree
CRA	corrosion-resistant alloy
CRM	corrosion-resistant material
EDP	emergency disconnect package (see ISO 13628-7)
FAT	factory acceptance test
FEA	finite element analysis
GRA	guidelineless re-entry assembly
HXT	horizontal subsea tree
ID	inside diameter
LRP	lower riser package (see ISO 13628-7)
LWRP	lower workover riser package (LRP + EDP) (see ISO 13628-7)
NACE	National Association of Corrosion Engineers
NDE	non-destructive examination
OD	outside diameter
OEC	other end connectors
PGB	permanent guidebase
PMR	per manufacturer's rating
PMV	production master valve
PR2	performance requirement level two
PSL	product specification level
PSV	production swab valve
PWV	production wing valve
QTC	qualification test coupon
RMS	root mean square
ROT	remotely operated tool (see ISO 13628-9)
ROV	remotely operated vehicle (see ISO 13628-8)
RWP	rated working pressure
S_b	bending stress

S_m	membrane stress
S_Y	yield strength
SCSSV	surface-controlled subsurface safety valve
SCF	stress concentration factor
SIT	system integration test
SWL	safe working load
TFL	through-flowline (see ISO 13628-3)
TGB	temporary guidebase
USV	underwater safety valve (see ISO 10423)
VXT	vertical subsea tree
WCT-BOP	wireline/coil tubing blowout preventer (see ISO 13628-7)
XOV	cross-over valve
XT	subsea tree

4 Service conditions and production 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 is designed.

4.1.2 Pressure ratings

Pressure ratings indicate 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 classifications

Temperature classifications indicate temperature ranges, from minimum (ambient or flowing) to maximum flowing fluid temperatures, expressed in degrees Celsius (°C), with equivalent degrees Fahrenheit (°F) given in parentheses. Classifications are listed in ISO 10423.

4.1.4 Sour service designation and marking

For material classes DD, EE, FF and HH, the manufacturer shall meet the requirements of ISO 15156 (all parts) for material processing and material properties (e.g. hardness). Choosing material class and specific materials for specific conditions is ultimately the responsibility of the purchaser.

Material classes DD, EE, FF, HH shall include as part of the designation and marking the maximum allowable partial pressure of H₂S, expressed in pounds per square inch absolute. The maximum allowable partial pressure shall be as defined by ISO 15156 (all parts) at the designated API temperature class for the limiting component(s) in the equipment assembly.

EXAMPLE "FF-1,5" indicates material class FF rated at 1,5 psia H₂S maximum allowable partial pressure.

Where no H₂S limit is defined by ISO 15156 (all parts) for the partial pressure, "NL" shall be used for marking (e.g., "DD-NL").

Users of this part of ISO 13628 should recognize that resistance to cracking caused by H₂S is influenced by a number of other factors for which some limits are given in ISO 15156 (all parts). These include, but are not limited to,

- pH;
- temperature;
- chloride concentration;
- elemental sulfur.

NOTE For the purposes of the provisions in this subclause, ANSI/NACE MR0175/ISO 15156 is equivalent to ISO 15156 (all parts).

In making the material selections, the purchaser should also consider the various environmental factors and production variables listed in Annex A.

4.1.5 Material classes

It is the responsibility of the end user to specify materials of construction for pressure-containing and pressure-controlling equipment. Material classes AA-HH as defined in Table 1 shall be used to indicate the material of those equipment components. Guidelines for choosing material class based on the retained fluid constituents and operating conditions are given in Annex M.

4.2 Product specification levels

Guidelines for selecting an appropriate product specification level (PSL) are provided in Annex M. The PSL of an assembled system of wellhead or tree equipment shall be determined by the lowest PSL of any pressure-containing or -controlling component in the assembly. Structural components and other non-pressure-containing/-controlling parts of equipment manufactured to this part of ISO 13628 are not defined by PSL requirements but by the manufacturer's specifications.

All pressure-containing components of equipment manufactured to this part of ISO 13628 shall comply with the requirements of PSL 2, PSL 3, or PSL 3G as established in ISO 10423. Pressure-controlling components shall comply with the requirements of PSL 2, PSL 3, or PSL 3G as specified in 5.4 and ISO 10423, except where additions or modifications are noted within this part of ISO 13628. These PSL designations define different levels of requirements for material qualification, testing, and documentation. PSL 3G does not necessarily imply that an assembly shall be gas-tested beyond the component/subassembly level (such as individual valves, chokes, tubing hangers, etc.). The purchaser shall specify whether it is required to gas-test an upper-level assembly manufactured to PSL 3G (such as a VXT or HXT assembly) as an integral unit at FAT.

5 Common system requirements

5.1 Design and performance requirements

5.1.1 General

5.1.1.1 Product capability

Product capability is defined by the manufacturer based on analysis and testing, more specifically:

- validation 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 (as specified in 5.1.1 and 5.1.2), which is demonstrated by reference to both factory acceptance testing and relevant validation testing data.

Performance requirements are specific and unique to the product in the “as-shipped” condition. All products shall be designed and qualified for their application in accordance with 5.1, 6.1, and Clauses 7 through 11.

5.1.1.2 Pressure integrity

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

5.1.1.3 Thermal integrity

Product designs shall be capable of functioning throughout the temperature range for which the product is rated. Components shall be rated and qualified for the maximum and minimum operating temperatures that they can experience in service, Joule-Thompson cooling effects, imposed flowline heating or heat-retention (insulation) effects. Thermal analysis can be used to establish component temperature-operating requirements. ISO 10423 provides information for design and rating of equipment for use at elevated temperatures.

5.1.1.4 Materials

Product shall be designed with an appropriate material class selected from Table 1, and shall conform to the requirements of ISO 10423.

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 ^a	Carbon or low alloy steel ^b	Carbon or low alloy steel ^b
EE-Sour service ^a	Carbon or low alloy steel ^b	Stainless steel ^b
FF-Sour service ^a	Stainless steel ^b	Stainless steel ^b
HH-Sour service ^a	CRAs ^{b,c,d}	CRAs ^{b,c,d}
NOTE Refer to 5.1.2.3 for information regarding material class selection.		
^a As defined in ISO 10423; in accordance with ISO 15156 (all parts). ^b In accordance with ISO 15156 (all parts). ^c CRA required on retained fluid wetted surfaces only; CRA cladding of low-alloy or stainless steel is permitted. ^d CRA as defined in 3.1.13. The definition of CRA in ISO 15156 (all parts) does not apply. NOTE For the purposes of the provisions in this table, ANSI/NACE MR0175/ISO 15156 is equivalent to ISO 15156 (all parts).		

5.1.1.5 Load capability

Product designs shall be capable of sustaining rated loads without deformation to such an extent that prevents meeting any other performance requirement, 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.

Design requirements and criteria found in this part of ISO 13628 are based on rated working pressure and external loads relevant for installation, testing and normal operations. Additional design requirements due to drilling-riser- or workover-riser-imparted loads should be considered by the manufacturer, and overall operating limits documented. ISO 13628-7 specifies design requirements for the workover riser and includes additional operational conditions, such as extreme and accidental events (vessel drive-off, drift-off or motion-compensator lock-up). These load conditions shall be considered for qualifying the equipment; see 5.1.7. The purchaser should confirm that anticipated operating loads are within the operating limits of the equipment being used for the specific application.

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. Products should be designed to operate for the required pressure/temperature cycles, cyclic external loads and multiple make/break (latch/unlatch), as applicable and where applicable as verified in validation testing.

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 validation testing.

5.1.1.8 Stored energy

The design shall consider the release of stored energy and ensure that this energy can safely be released prior to the disconnection of fittings, assemblies, etc. Notable examples of this include, but are not limited to, trapped pressure and compressed springs.

5.1.2 Service conditions

5.1.2.1 Pressure ratings

5.1.2.1.1 General

Pressure ratings shall comply with 5.1.2.1.2 to 5.1.2.1.8. 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 designed 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; see 7.9.1 and 9.2.7 for additional information. 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 rated working pressure (3.1.41).

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) should be considered.

5.1.2.1.2 Subsea trees

5.1.2.1.2.1 Standard pressure rating

Whenever feasible, assembled equipment that contains and controls well pressure, such as valves, chokes, wellhead housings and connectors, shall be specified by the purchaser, and designed and manufactured to one of the following standard rated working pressures: 34,5 MPa (5 000 psi), 69 MPa (10 000 psi) or 103,5 MPa (15 000 psi). Standard pressure ratings facilitate safety and interchangeability of equipment, particularly where end connections are in accordance with this part of ISO 13628 or other industry standard, such as ISO 10423. Intermediate pressure ratings, e.g. 49,5 MPa (7 500 psi), for pressure-controlling and pressure-containing parts are not considered except for tubing-hanger conduits and/or tree penetrations and

connections leading to upstream components in the well (such as SCSSVs, chemical-injection porting, sensors), which may have a higher-than-working-pressure design requirement.

5.1.2.1.2.2 Non-standard working pressure rating

Non-standard pressure ratings are outside the scope of this part of ISO 13628.

5.1.2.1.3 Tubing hangers

The standard RWP for subsea tubing hangers shall be 34,5 MPa (5 000 psi), 69 MPa (10 000 psi) and 103,5 MPa (15 000 psi). The production or annulus tubing connection may have a pressure rating lower than the tubing hangers RWP. Also, the tubing hanger may contain flow passages that shall not exceed 1,0 times the RWP of the tubing hanger assembly plus 17,2 MPa (2 500 psi).

5.1.2.1.4 Subsea wellhead equipment

The standard RWP for subsea wellheads shall be 34,5 MPa (5 000 psi), 69 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, connection thread and operating requirements.

5.1.2.1.5 Mudline equipment

Standard rated working pressures do not apply to mudline casing hanger and tieback equipment. Instead, each equipment piece shall be rated for working pressure in accordance with the methods given in Clause 10 and Annex E.

5.1.2.1.6 Hydraulically controlled components

All hydraulically operated components and hydraulic control lines that are not exposed to wellbore fluids shall have a hydraulic RWP (design pressure) in accordance with the manufacturer's written specification. All components that use the hydraulic system to operate should be designed to perform their intended function at 0,9 times hydraulic RWP or less, and shall be able to withstand occasional pressure anomalies to 1,1 times hydraulic RWP.

5.1.2.1.7 Thread limitations

Equipment designed for a mechanical connection with small-bore connections [up to 25,4 mm (1,00 in) bore], test ports and gauge connections shall be internally threaded, shall conform to the limits on use specified in 7.3 and shall conform to the size and RWP limitations given in Table 2. OECs, with internal threads and meeting the requirements of 7.3 that are designed specifically for small-bore, test-port or gauge-connection applications, may also be used.

Table 2 — Pressure ratings for internal thread connections

Type of thread	Size mm (in)	Rated working pressure MPa (psi)
API line pipe (sizes)	12,7 (1/2)	69,0 (10 000)
High-pressure connections	Types I, II and III in accordance with ISO 10423	103,5 (15 000)

5.1.2.1.8 Other equipment

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

5.1.2.2 Temperature ratings

5.1.2.2.1 Standard operating temperature rating

Equipment covered by this part of ISO 13628 shall be designed and rated to operate throughout a temperature range defined by the manufacturer and as a system in accordance with ISO 10423. The minimum temperature rating for valve and choke actuators shall be 2 °C (35 °F) to 66 °C (151 °F). The minimum classification for the subsea system in accordance with ISO 13268-4 shall be temperature classification V [2 °C (35 °F) to 121 °C (250 °F)]. When impact toughness is required of materials (PSL 3 and PSL 3G), the minimum classification for pressure-containing and pressure-controlling materials should be temperature classification U [– 18 °C (0 °F) to 121 °C (250 °F)].

Pre-deployment testing at the surface may be conducted at environmental temperatures lower than the system rating as specified by the manufacturer. It is not necessary that the product qualification be performed at the pre-deployment testing temperature.

Consideration should be given to equipment operation due to transitional low-temperature effects on choke bodies and associated downstream components when subject to Joule-Thompson (J-T) cooling effects due to extreme gas-pressure differentials.

Transitional low-temperature effects associated with J-T cooling and well start-up conditions may be addressed by one or more of the following methods:

- a) component validation to the required minimum temperature as specified in 5.1.7;
- b) component validation to the standard operating temperature range combined with material Charpy V-notch qualification at or below the minimum transitional operating temperature in accordance with 4.1.3;
- c) component validation to the standard operating temperature range combined with additional material documentation supporting suitability for operation at the transitional temperature range.

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 66 °C (150 °F) when operated subsea with a retained fluid at least 121 °C (250 °F), then this equipment may be designed and rated to operate throughout a temperature range of 2 °C (35 °F) to 66 °C (150 °F).

Conversely, subsea components and equipment that are thermally shielded from sea water by insulating materials shall demonstrate that they can work within temperature range of the designated temperature classification.

5.1.2.2.3 Temperature design considerations

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

5.1.2.2.4 Storage/test temperature considerations

If subsea equipment will 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 constructed with materials (metallics and non-metallics) suitable for its respective material classification in accordance with Table 1. Table 1 does not define all factors within the wellhead environment, but provides material classes for various levels of service conditions and relative corrosivity.

5.1.2.3.2 Material classes

Material selection is the ultimate responsibility of the user as he has the knowledge of the production environment as well as control over the injected treatment chemicals. The user may specify the service conditions and injection chemicals, asking the supplier to recommend materials for his review and approval.

Material requirements shall comply with Table 1. All pressure-containing components shall be treated as "bodies" for determining material trim requirements from Table 1. However, in this part of ISO 13628, other wellbore-pressure boundary-penetration equipment, such as grease and bleeder fittings, shall be treated as "stems" as set forth in Table 1. Metal seals shall be treated as pressure-controlling parts with regards to Table 1.

All pressure-containing components exposed to well-bore fluids shall be in accordance with ISO 15156 (all parts) and Table 1 material classes AA-HH.

5.1.3 Design methods and criteria

5.1.3.1 General

Structural strength and fatigue strength shall be evaluated in this part of ISO 13628. ASME *BPVC*, Section VIII, Division 2, Appendix 5, or other recognized standards may be used when calculating fatigue. Localized bearing-stress values are beyond the scope of this part of ISO 13628. The effects of external loads (i.e. bending moment, tensions, etc.) on the assembly or components are not explicitly addressed in this part of ISO 13628 or in ISO 10423. As equipment covered by this part of ISO 13628 are exposed to external loads, ISO 13628-7 may be used to define the structural strength design.

The purchaser shall confirm that anticipated operating loads are within the operating limits of the equipment being used for the specific application.

5.1.3.2 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.

5.1.3.3 Pressure-controlling components

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

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

5.1.3.4 Pressure-containing components

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

5.1.3.5 Closure bolting and critical bolting

Closure bolting (pressure-containing) and critical bolting (high-load bearing) require a preload to a high percent of material yield strength as noted below.

Closure bolting of all 6BX and 17SS flanges shall be made up using a method that has been shown to result in a stress range between 67 % and 73 % of the bolt's material yield stress.

This stress range should result in a preload in excess of the separation force at test pressure while avoiding excessive stress beyond 83 % of the bolt material's yield strength.

Closure bolting manufactured from carbon or alloy steel, when used in submerged service, shall be limited to 321 HBN (Rockwell "C" 35) maximum due to concerns with hydrogen embrittlement when connected to cathodic protection. Closure bolting for material classes AA-HH that is covered by insulation shall be treated as exposed bolting in accordance with ISO 15156 (all parts).

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 limits given in ISO 10423.

5.1.3.6 Primary structural components

Primary structural components, such as guidebases, shall be designed in accordance with accepted industry practices and documented in accordance with 5.1.5. A safety/design factor of 1,5 or more based on the minimum material yield strength shall be used in the design calculations; other recognized industry codes may be used. It should be noted that many codes already include safety factors. Alternatively, an FEA may be used to demonstrate that applied loads do not result in deformation to such an extent that prevents meeting any other performance requirement. As an alternative, a design validation load test of 1,5 times its rated capacity may be substituted for design analysis. The component shall sustain the test loading without deformation to such an extent that any other performance requirement is affected and the test documents shall be retained.

For other load conditions, the design (safety) factors given in ISO 13628-7 apply.

5.1.3.7 Specific equipment

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

5.1.3.8 Design of equipment for lifting

5.1.3.8.1 General

Lifting devices are divided into two categories for design and testing: permanently installed lifting equipment and reusable lifting equipment. Testing of reusable lifting equipment is more stringent as this equipment is subject to lifting cycles throughout its lifetime. Annex K provides design, testing, and maintenance guidelines for both reusable lifting equipment and permanently installed equipment.

Equipment used exclusively for running in, on or out of the wellbore should be designed as given in 5.1.3.6 or 5.1.3.7, Annex H or Annex K, as applicable.

5.1.3.8.2 Pad eyes

Pad eyes should be designed as given in Annex K. Load capacities of pad eyes shall be marked as specified in 5.5.2.

5.1.3.8.3 Primary members

Primary members are structural members that are in the direct load path of lifting loads. If the primary member is either pressure-containing or pressure-controlling, and is designed to be pressurized during lifting operations, then the load capacity shall include the additional stresses induced by internal rated working pressure.

5.1.3.8.4 Load testing

Load testing of lifting pad eyes should be done in accordance with Annex K.

5.1.4 Miscellaneous design information

5.1.4.1 Fraction to decimal equivalence

ISO 10423, Annex B, gives the equivalent fraction and decimal values.

5.1.4.2 Tolerances

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

- a) The tolerance for dimensions with format X is $\pm 0,5$ mm (X,X is $\pm 0,02$ in).
- b) The tolerance for dimensions with format X,X is $\pm 0,5$ mm (X,XX is $\pm 0,02$ in).
- c) The tolerance for dimensions with format X,XX is $\pm 0,13$ mm (X,XXX is $\pm 0,005$ in).
- d) Dimensions listed as $\frac{XXXX}{YYYY}$ are considered the maximum dimension ($XXXX$) and the minimum dimension ($YYYY$), overriding the nominal tolerances to accommodate certain geometries.

Dimensions less than 10 mm (0,39 in) should be listed with two digit accuracy so that the imperial equivalent is within the same two-digit manufacturing tolerance.

5.1.4.3 End and outlet bolting

5.1.4.3.1 Hole alignment

End and outlet bolt holes for ISO flanges shall be equally spaced and shall straddle the common centre line; see Table 7.

5.1.4.3.2 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.

5.1.4.4 Other bolting

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

5.1.4.5 Test, vent, injection and gauge connections

5.1.4.5.1 Sealing

All test, vent, injection and gauge connections shall provide a leak-tight 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 removal of the component.

5.1.4.5.2 Test and gauge connection ports

Test and gauge connection ports shall comply with the requirements of 5.1.2.1.7 and 7.3.

5.1.4.6 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 that 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.

5.1.4.7 Coatings (external)

5.1.4.7.1 Methods

The coating system and procedure used shall comply with the written specification of the equipment manufacturer or the coating manufacturer as agreed between the user/purchaser and manufacturer. In the event neither has a specification, Annex I may be used.

5.1.4.7.2 Record retention

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

5.1.4.7.3 Colour selection

Colour selection for underwater visibility shall be in accordance with ISO 13628-1.

5.1.4.8 Cathodic protection

5.1.4.8.1 Cathodic-protection system design requires the consideration of the external area of the equipment being 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 in accordance with 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.

5.1.4.8.2 The following cathodic protection design codes shall apply:

- NACE SP0176;
- DNV RP B401.

5.1.4.8.3 Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Care should be exercised in the selection of materials for applications requiring high strength, corrosion resistance and resistance to hydrogen embrittlement. Materials that have shown this susceptibility include martensitic stainless steels and the more highly alloyed steels having yield strengths over 900 MPa (131 000 psi). Other materials subject to this phenomenon are hardened, low-alloy steels, particularly with hardness levels greater than Rockwell "C" 35 [with yield strength exceeding 900 MPa (131 000 psi)], precipitation-hardened nickel-copper alloys and some high-strength titanium alloys.

5.1.5 Design documentation

Documentation of designs shall include methods, assumptions, calculations, qualification test reports and design-validation requirements. Design documentation requirements shall include, but not be limited to, those criteria for size, test and operating pressures, material, environmental requirements and other pertinent requirements on which the design is being based. Design documentation media shall be clear, legible, reproducible and retrievable. Design documentation retention shall be for a minimum of five 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 individual other than the individual who created the original design.

5.1.7 Validation testing

5.1.7.1 Introduction

The minimum validation test procedures that shall be used to qualify product designs in accordance with Table 3 are defined in 3.5.1.7. The manufacturer shall define additional validation tests that are applicable and demonstrate that this validation testing can be correlated with the intended service life and/or operating conditions in accordance with the purchaser requirements.

5.1.7.2 General

Prototype equipment (or first article) and fixtures used to qualify designs using these validation procedures shall be representative of production models in terms of design, production dimensions/tolerances, intended manufacturing processes, deflections 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 that affects the performance of the product in the intended service condition. A substantive change is considered as any change from the previously qualified configuration or material selection that can affect performance of the product or intended service. This shall be recorded and the manufacturer shall justify whether or not re-qualification is required. This may include changes in fit-form-function or material. A change in material might not require retesting if the suitability of the new material can be substantiated by other means.

NOTE Fit, when defined as the geometric relationship between parts, includes the tolerance criteria used during the design of a part and mating parts. Fit, when defined as a state of being adjusted to, or shaped for, includes the tolerance criteria used during the design of a seal and its mating parts.

For items with primary and secondary independent seal mechanisms, the seal mechanisms shall be independently verified. Equipment should be qualified with the minimal lubricants required for assembly unless the lubricants can be replenished when the equipment is in service or is provided for service in a sealed chamber.

The actual dimensions of equipment subjected to validation test shall be within the allowable range for dimensions specified for normal production equipment. Worst-case conditions for dimensional tolerances should be addressed by the manufacturer, giving consideration to concerns such as sealing and mechanical functioning.

5.1.7.3 Test media

Gas shall be used as the test medium for pressure-hold periods for pressure-containing and -controlling equipment. Other equipment may be hydrostatically tested.

Manufacturers may, at their option, substitute a gas test for some or all of the required validation pressure tests. Validation test procedures and acceptance criteria shall meet the requirements in 5.4.

5.1.7.4 Pressure-cycling tests

Table 3 lists equipment that shall be subjected to repetitive hydrostatic (or gas, if applicable) pressure-cycling tests simulating start-up and shutdown pressure cycling that occurs in long-term field service. For these hydrostatic cycling tests, the equipment shall be alternately pressurized to the full rated working pressure and then fully depressurized until the specified number of pressure cycles has 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 both validation testing and engineering analysis. The equipment shall be loaded to the rated capacity to the number of cycles in accordance with Table 3 during the test without deformation to such an extent that any other performance requirement is affected (unless otherwise specified). Engineering analysis shall be conducted using techniques and programmes that comply with documented industry practice.

See 5.1.3.3 for load-testing of pressure-controlling components, and 5.1.3.6 for load-testing of primary structural components.

5.1.7.6 Temperature cycling tests

Validation tests shall be performed at a test temperature at or beyond the range of the rated operating temperature classification while at RWP or load condition.

Table 3 lists equipment that shall be subjected to repetitive temperature cycling tests simulating start-up and shutdown temperature cycling that 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 5.1.2.2. During temperature cycling, rated working pressure shall be applied to the equipment at the temperature extremes with no leaks beyond the acceptance criteria established in ISO 10423. As an alternative to testing, manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements at both temperature extremes.

5.1.7.7 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 being tested. Such tests may be conducted at a temperature specified by the manufacturer and documented as appropriate for that product and rating. Table 3 lists equipment that 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, including stabs, shall be subjected to a full disconnect/lift as part of the cycle. Additional specifications for life-cycle/endurance testing of the components listed in Table 3 can 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. Where it can be demonstrated that pressure and/or temperature testing similarly loads the component or assembly to that condition specified for endurance-cycle testing, those cycles can be accumulated toward the total number of cycles specified for endurance-cycle testing. For example, the 200/3 pressure/temperature cycles used to test a valve can cumulatively qualify as 203 cycles toward the 600 total cycles required for endurance cycling.

Table 3 — Minimum validation test requirements

Component	Pressure/load cycling test	Temperature cycling test ^a	Endurance cycling test (total cumulative cycles)
Metal seal exposed to well bore in production	200	3	PMR ^c
Metal seal not exposed to well bore in production	3	3	PMR ^c
Non-metallic seal exposed to well bore in production	200	3	PMR ^c
Non-metallic seal not exposed to well bore in production	3	3	PMR ^c
OEC	200	NA	PMR ^c
Wellhead/tree/tubing head connectors	3	NA	PMR ^c
Workover/intervention connectors	3	NA	100
Tubing heads	3	NA	NA
Valves ^b	200	3	600
Valve actuators	200	3	600
Tree cap connectors	3	NA	PMR ^c
Flowline connectors	200	NA	PMR ^c
Subsea chokes	200	3	500
Subsea choke actuators	200	3	1 000 ^e
Subsea wellhead casing hangers	3	NA	NA
Subsea wellhead annulus seal assemblies (including emergency seal assemblies)	3	3	NA
Subsea tubing hangers, HXT internal tree caps and crown plugs	3	NA	NA
Poppets, sliding sleeves, and check valves	200	3	PMR ^c
Mudline tubing heads	3	NA	NA
Mudline wellhead, casing hangers, tubing hangers	3	NA	NA
Running tools ^d	3	NA	PMR ^c
NOTE Pressure cycles, temperature cycles and endurance cycles are run as specified above in a cumulative test with one product without changing seals or components.			
^a Temperature cycles shall be in accordance with ISO 10423. ^b Before and after the pressure cycle test a low-pressure, 2 MPa (300 psi) $\pm$ 10 %, leak-tightness test shall be performed. ^c PMR signifies "per manufacturer rating". ^d Subsea wellhead running tools are not included. ^e A choke-actuator cycle is defined as total choke stroke from full-open to full-close or full-close to full-open.			

5.1.7.8 Product family validation

A product of one size may be used to verify other sizes in a product family, providing the following requirements are met.

- a) A product family is a group of products for which the design principles, physical configuration, and functional operation are the same, but which differ in size.
- b) The product geometries shall be parametrically modelled such that the design stress levels and deflections in relation to material mechanical properties are based on the same criteria for all members of the product family in order to verify designs via this method.
- c) Scaling may be used to verify the members of a product family in accordance with ISO 10423, Annex F.

5.1.7.9 Documentation

The manufacturer shall document the procedures used and the results of all validation tests used to qualify equipment in this part of ISO 13628. The documentation requirements for validation testing shall be the same as the documentation requirements for design documentation in 5.1.5 with the addition that the 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 heads 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.

For forged material used for pressure-containing and high-load-bearing parts, forging practices, heat treatment and test coupon (QTC or prolongation) requirements should meet those of API RP 6HT. In addition, the test coupon shall accompany the material it qualifies through all thermal processing, excluding stress relief.

"High-load-bearing" describes a load condition acting on a component such that the resulting loaded equivalent stress exceeds 50 % of the base-material's minimum yield strength.

5.2.3 Product specification level

The pressure-containing and pressure-controlling materials used in equipment covered by this part of ISO 13628 shall comply with requirements for PSL 2 or PSL 3/3G in accordance with ISO 10423. All other items should be in accordance with the manufacturer's written specification.

5.2.4 Corrosion considerations

5.2.4.1 Corrosion from retained fluids

Material selection based upon wellbore fluids shall be made in accordance with 5.1.2.3.

5.2.4.2 Corrosion from marine environment

Corrosion protection through material selection based on 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 that conforms to the requirements of the design may be used.

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 for PSL 2 or PSL 3/3G, as specified.

5.3.2 Structural components

Structural welds shall be treated as non-pressure-containing welds and shall comply with ISO 10423 or a documented structural welding code, such as AWS D1.1. Weld locations where the loaded stress exceeds 50 % of the weld or base-material yield strength, and welded pad eyes for lifting shall be identified as “critical welds” and shall be treated as in 5.3.1, PSL 3/3G.

5.3.3 Corrosion-resistant overlays

5.3.3.1 General

Corrosion resistant overlays shall be made in accordance with ISO 10423 requirements with regard to the following:

- a) welding requirements for weld overlay for corrosion-resistance and/or hard facing and other material surface-property controls,
- b) quality requirements for welding, in accordance with 5.3.3.2 to 5.3.3.5.

5.3.3.2 Ring grooves

Overlay of ring grooves shall meet the applicable requirements of ISO 10423 with regard to the following:

- a) weld overlay requirements in ISO 10423 for corrosion-resistant ring grooves;
- b) quality requirements in ISO 10423 for weld-metal overlay (ring grooves, stems, valve bore sealing mechanisms and choke trim).

NOTE Overlay of ring grooves is typically intended to provide corrosion-resistance only.

5.3.3.3 Stems, valve bore sealing mechanisms and choke trim

Overlay of stems, valve bore sealing mechanisms (VBSM), and choke trim shall meet the applicable requirements of ISO 10423 with regard to the following:

- a) weld overlay requirements in ISO 10423 for other corrosion-resistant overlays;
- b) quality requirements in ISO 10423 for weld-metal overlay (ring grooves, stems, valve-bore sealing mechanisms and choke trim).

NOTE Overlay of stems, valve bore sealing mechanisms and choke trim is typically intended to provide both corrosion resistance and wear resistance.

5.3.3.4 CRM overlay of wetted surfaces, pressure-containing parts

Overlay of wetted surfaces on pressure-containing parts shall meet applicable requirements of ISO 10423 with regard to the following:

- a) weld overlay requirements in ISO 10423 for other corrosion-resistant overlays;
- b) quality requirements in ISO 10423 for weld-metal corrosion-resistant alloy overlay (bodies, bonnets, end and outlet connections).

NOTE CRM overlay of wetted surfaces on pressure-containing parts is typically intended to meet the requirements of ISO 10423 material class HH, and/or high resistance to seawater and retained fluids. This category does not include localized CRM overlay of seal surfaces only.

5.3.3.5 Other corrosion-resistant overlay of seal surfaces

Overlay of seal surfaces on pressure-containing and pressure-controlling parts shall meet applicable requirements of ISO 10423 with regard to the following:

- a) weld overlay requirements in ISO 10423 for other corrosion-resistant overlays;
- b) quality requirements, which shall be specified by the manufacturer and shall meet, as a minimum, requirements in ISO 10423 for weld-metal overlay (ring grooves, stems, valve-bore sealing mechanisms and choke trim).

NOTE Localized CRM overlay of seal surfaces on pressure-containing or pressure-controlling parts is typically intended to provide enhanced corrosion resistance for critical seal interfaces. This is distinct from full CRM overlay of wetted surfaces to meet material class requirements.

Requirements established by the manufacturer shall include consideration of design requirements for the overlay.

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 manufacturer's written specifications. Purchaser and manufacturer should agree on any additional requirements.

5.4.2 Product specification level

Quality control and testing for pressure-containing and pressure-controlling components covered by this part of ISO 13628 shall comply with requirements for PSL 2 or 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. Requirements for other components shall be in accordance with the manufacturer's written specification.

5.4.3 Structural components

Quality control and testing of welding for structural components shall be specified as non-pressure-containing welds and comply with ISO 10423 or a documented structural welding code, such as AWS D.1.1. "Critical welds" shall be treated as pressure-controlling welds and comply with ISO 10423, PSL 3, excluding volumetric NDE examination.

5.4.4 Lifting devices

Guidelines for lifting pad eyes are defined in Annex K.

Additionally, welds on pad eyes and other lifting devices attached by welding shall be in accordance with the weld requirements as specified in 5.3.2 and 5.4.3. All pad eye and lifting device welds shall be designated as "critical welds". Lifting pad eyes shall also be individually proof-load tested to at least two and one-half (2,5) times the documented safe working load for the individual pad eye (SWL/number of pad eyes). Pad eyes shall be tested with magnetic particles and/or dye penetrant following proof testing. Proof-load testing shall be repeated following significant repairs or modifications prior to being put into use. The base metal and welds of pad eyes and other lifting devices shall meet PSL 3 requirements.

5.4.5 Testing for PSL 2 and PSL 3 equipment

5.4.5.1 Hydrostatic pressure testing

Procedures for hydrostatic pressure testing of equipment specified in Clauses 6 through 11 shall conform to the requirements for PSL 2 or PSL 3 in accordance with 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. The acceptance criterion for hydrostatic pressure tests shall be no visible leakage during the hold period. If a pressure-monitoring gauge and/or a chart recorder is used for documentation purposes, the chart record should have an acceptable pressure settling rate not exceeding 3 % of the test pressure per hour. The final settling pressure shall not fall below the test pressure before the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.

5.4.5.2 Drift test

Drift testing should be conducted in accordance with ISO 10423 after completion of pressure testing. Vertical runs that require the passage of wellbore tools shall be physically drifted with the ISO 10423-specified drift mandrel. Runs that require the passage of TFL tools shall be physically drifted with the ISO 13628-3 drift mandrels. Other configurations that do not allow the use of a physical drift mandrel due to access or length of run may be confirmed as to drift alignment by other means, such as the use of a borescope and visual inspection.

5.4.6 Testing for PSL 3G equipment

5.4.6.1 Drift test

See 5.4.5.2.

5.4.6.2 Pressure testing

5.4.6.2.1 Hydrostatic body and seat test for valves and chokes

A hydrostatic body test and hydrostatic valve seat tests shall be performed prior to any gas testing.

The acceptance criterion for hydrostatic pressure tests shall be no visible leakage during the hold period. If a pressure-monitoring gauge and/or a chart recorder is used for documentation purposes, the chart record should have an acceptable pressure settling rate not exceeding 3 % of the test pressure per hour. The final settling pressure shall not fall below the test pressure before the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.

5.4.6.2.2 Gas body test for assembled valves and chokes

The test shall be conducted under the following conditions.

- a) The test shall be conducted at ambient temperature.
- b) The test medium shall be nitrogen.
- c) The test shall be conducted with the equipment completely submerged in a water bath.
- d) The 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 acceptance criterion for gas tests shall be no visible bubbles during the hold period. If a pressure-monitoring gauge and/or chart recorder is used for documentation purposes, the chart record should have a pressure settling rate not exceeding 3 % of the test pressure per 15 min or per 2 MPa (300 psi), whichever is less. The final settling pressure shall not fall below the test pressure before the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.

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) The gas pressure shall be applied to 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 shall 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) The pressure shall be reduced to zero between the primary and secondary hold points, but not by opening the valve.
- i) The secondary test pressure shall be 2 MPa $\pm$ 0,2 MPa (300 psi $\pm$ 30 psi).
- j) The secondary test monitored hold period shall be 15 min; the upstream pressure is then vented to zero, but not by opening the valve.

- k) The valves shall be fully opened and fully closed between tests.
- l) Bi-directional valves shall be tested on the other side of the gate or plug using the same procedure.

The acceptance criterion for gas tests shall be no visible bubbles during the hold period.

For the primary high-pressure seat test, if a pressure-monitoring gauge and/or chart recorder is used for documentation purposes, the chart record should have a pressure settling rate not exceeding 3 % of the test pressure per 15 min or per 2 MPa (300 psi), whichever is less. The final settling pressure shall not fall below the test pressure before the end of the test hold period. Initial test pressure shall not be greater than 5 % above the specified test pressure.

For the secondary low pressure seat test, the test pressure shall be 2 MPa $\pm$ 0,2 MPa (300 psi $\pm$ 30 psi) over the hold period.

5.4.7 Hydraulic system pressure testing

Components that contain a hydraulic control fluid shall be tested to a hydrostatic body/shell test at 1,5 times the hydraulic RWP of their respective hydraulic systems with primary and secondary hold times in accordance with 5.4, PSL 3. All operating subsystems (actuators, connectors, etc.) that are operated by the hydraulic system shall function at 0,9 times the hydraulic RWP or less of their respective system.

As the hydraulic system does not communicate with the wellbore, its RWP shall be limited to the weakest pressure-containing element or less, as specified by the manufacturer. The hydrostatic test pressure of the hydraulic system shall be 1,5 times the hydraulic RWP with primary and secondary hold times in accordance with 5.4, PSL 3. The test medium is the hydraulic system fluid. Acceptance criterion is no visible leakage. Chart recording is not required.

5.4.8 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 where the resistance is greater than 0,10 Ω .

5.5 Equipment marking

5.5.1 General

Equipment that meets the requirements of this International Standard shall be marked "ISO 13628-4" in accordance with ISO 10423, marking "ISO 13628-4" in place of "ISO 10423."

All equipment marked "ISO 13628-4" shall, also, be marked with the following minimum information: part number, manufacturer name or trademark. See ISO 10423 for metallic marking locations.

Equipment shall be marked in either metric units or imperial units where size information is applicable and useful. The units shall be marked together with the numbers.

5.5.2 Pad eyes and lift points

Pad eyes intended for lifting an assembly should be painted red and properly marked for lifting so as to alert personnel that safe handling can be made from this point.

Lift pad eyes or lift points on each respective assembly shall be marked with the documented total safe working load (SWL) as follows.

EXAMPLE 1 Using a four-pad eye lift arrangement, each with a static safe working load of 25 tons, yields a total safe working load (SWL) of 100 tons with a sling load lift-angle limit ($90^\circ - \alpha$) of 60° from horizontal. The static marking at or near the lift location is as follows:

"100 tons total SWL static, 4 point lift, 60-90"

EXAMPLE 2 For offshore or immersion (subsea) lift conditions, the marking for the total dynamic safe working load should be marked in addition to the static load marking. The reduced SWL capacity reflects load amplification factors (LAF) that are listed in Annex K.

"50 tons total SWL dynamic, 4 point lift, 60-90"

SAFETY PRECAUTIONS — Pad eyes on frames not painted red and/or properly labeled should be considered only as aids for handling lines (tag lines) or tie-down (transportation, sea fastening, etc.). Any pad eye or lift point not properly marked with the appropriate lift marking should not be used for lifting. Lifting from unmarked pad eyes can lead to serious damage or injury.

Personnel should pay special attention to payload weights and their markings and, in particular its spelling, to make sure total safe working loads match rigging requirements: "tons" refers to an imperial ton (2 240 lbs); "s ton" refers to a "short ton" (2 000 lbs); "tonne" refers to a metric ton (1 000 kg or 2 200 lb).

All assemblies and equipment that are handled between supply boat and rig may have dedicated lifting equipment (sling assemblies, etc.), which comply with local legislation or regulations. All packages exceeding 100 kN (22 500 lbs) shall have pad eyes for handling and sea fastening. These pad eyes shall not be painted red and should be considered only as aids for handling lines (tag lines) or tie-down (transportation, sea fastening, etc.). Any pad eye not stamped or stenciled with the appropriate lift marking should not be used for lifting. Lifting from unmarked pad eyes can lead to serious damage or injury. All other equipment not suitable for shipping in baskets or containers shall be furnished with facilities for sea fastening as appropriate.

5.5.3 Other lifting devices

The rated lifting capacity of other lifting devices, such as tools, as determined in 5.1.3.8, shall be clearly marked in accordance with 5.5.2 in a position visible when the lifting device is in the operating position.

5.5.4 Temperature classification

Subsea equipment manufactured in accordance with 5.1.2.2 shall be marked with the appropriate temperature classification in accordance with ISO 10423.

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 and prior to storage or shipment.

5.6.2 Rust prevention

Prior to shipment, parts and equipment shall have exposed metallic surfaces (except those otherwise designated, such as anodes or nameplates) either protected with a rust preventive coating that does 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.