International
Association
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Producers

SPECIFICATION
S-561

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Supplementary Specification to API 17D Subsea Trees

Revision history

VERSION	DATE	AMENDMENTS
3.0	November 2018	Issued for Publication
2.0	November 2016	Issued for Use
1.0	September 2016	Initial issue

Acknowledgements

This IOGP Specification was prepared by a Joint Industry Project 33 Standardization of Equipment Specifications for Procurement organized by IOGP with support by the World Economic Forum (WEF).

Foreword

This specification was prepared under a Joint Industry Project 33 (JIP33) “Standardization of Equipment Specifications for Procurement” organized by the International Oil & Gas Producers Association (IOGP) with the support from the World Economic Forum (WEF). Ten key oil and gas companies from the IOGP membership participated in developing this specification under JIP33 Phase 2 with the objective to leverage and improve industry level standardization for projects globally in the oil and gas sector. The work has developed a minimized set of supplementary requirements for procurement, with life cycle cost in mind, based on the ten participating members’ company specifications, resulting in a common and jointly approved specification, and building on recognized industry and/or international standards.

This specification has been developed in consultation with a broad user and supplier base to promote the opportunity to realize benefits from standardization and achieve significant cost reductions for upstream project costs. The JIP33 work groups performed their activities in accordance with IOGP’s Competition Law Guidelines (November 2014).

Recent trends in oil and gas projects have demonstrated substantial budget and schedule overruns. The Oil and Gas Community within the World Economic Forum (WEF) has implemented a Capital Project Complexity (CPC) initiative which seeks to drive a structural reduction in upstream project costs with a focus on industry-wide, non-competitive collaboration and standardization. The vision from the CPC industry is to standardize specifications for global procurement for equipment and packages, facilitating improved standardization of major projects across the globe. While individual oil and gas companies have been improving standardization within their own businesses, this has limited value potential and the industry lags behind other industries and has eroded value by creating bespoke components in projects.

This specification aims to significantly reduce this waste, decrease project costs and improve schedule through pre-competitive collaboration on standardization. This document defines the supplementary requirements to the recognized industry standard ANSI/API Specification 17D Second Edition 2011, including all errata up to 7, October 2015 and Addendum 1, September 2015, Design & Operation of Subsea Production Systems – Subsea Wellhead and Tree Equipment (identical to ISO 13628-4, Second Edition 2010 Design and Operation of Subsea Production Systems: Subsea Wellhead and Tree Equipment) which is indispensable for the application of this specification.

Following agreement of the relevant JIP33 work group and approval by the JIP33 Steering Committee, the IOGP Management Committee has agreed to the publication of this specification by IOGP. Where adopted by the individual operating companies, this specification and associated documentation aims to supersede existing company documentation for the purpose of industry-harmonized standardization.

This supplementary specification (S-561) is an update to version 2.0 which was published in November 2016 as part of the pilot phase proof of concept for JIP33. This latest version incorporates supplier and member feedback as well as providing additional standardized tree configuration and guidance on the implementation of DNVGL-RP-0034 (Steel forgings for Subsea Applications).

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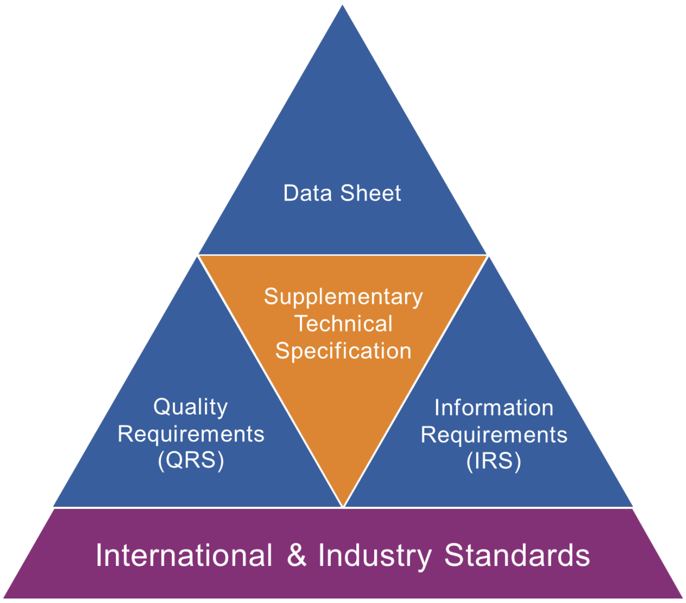
Introduction

The purpose of this specification is to define a minimum common set of supplementary requirements for procurement of subsea trees to API 17D, for application in the petroleum and natural gas industries.

This JIP33 standardized procurement specification follows a common document structure comprising the four documents as shown below, which together with the purchase order define the overall technical specification for procurement.



JIP33 Specification for Procurement Documents
Supplementary Technical Requirements

It is required to use all of these documents in conjunction with each other when applying this specification, as follows:

IOGP S-561: Supplementary specification to API 17D Subsea Trees

This specification is written as an overlay to API 17D, following the clause structure of the parent standard, to assist in cross-referencing the requirements. Where clauses from the parent standard (API 17D) are not covered in this specification, there are no supplementary requirements or modifications to the respective clause. The terminology used within this specification follows that of the parent standard and otherwise is in accordance with ISO/IEC Directives, Part 2.

Modifications to the parent standard defined in this specification are identified as *Add* (add to clause or add new clause), *Replace* (part of or entire clause) or *Delete*.

IOGP S-561D: Data sheet for subsea trees

This document provides project specific requirements where the supplementary specification and its parent standard require the user to define an application specific requirement. It follows the clause structure of the parent standard and this specification. It also includes information required by the user for technical evaluation. Additional purchaser supplied documents are also listed in the data sheet, to define scope and technical requirements for enquiry and purchase of the equipment.

IOGP S-561L: Information requirements specification (IRS) for subsea trees

This document defines the information requirements, including format, timing and purpose, for information to be provided by the manufacturer. It also defines the specific conditions which must be met for conditional information requirements to become mandatory. The information requirements listed in the IRS have references to the source of the requirement.

IOGP S-561Q: Quality requirements specification (QRS) for subsea trees

This document includes a conformity assessment system (CAS) which specifies standardized user interventions against quality management activities at four different levels. The applicable CAS level is specified by the user in the data sheet.

The data sheet and IRS are published as editable documents for the user to specify application specific requirements. The supplementary specification and QRS are fixed documents.

Unless defined otherwise in the purchase order, the order of precedence (highest authority listed first) of the documents shall be:

a) regulatory requirements;

b) contract documentation (e.g. purchase order);

c) user defined requirements (equipment data sheet, IRS, QRS);

d) this specification;

e) the parent standard.

1 Scope

Replace fourth paragraph and items a) to f) with

The scope of this specification (in conjunction with API 17D) defines the requirements for subsea tree systems. Equipment that is within the scope of this specification 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;
- re-entry interface;
- tree cap;
- tree piping;
- tree guide frames;
- tree running tools;
- tree cap running tools;
- tree mounted flowline/umbilical connector;
- tubing head and tubing head connectors;
- flowline bases and running/retrieval tools;
- tree mounted control interfaces (instrumentation, sensors, hydraulic tubing/piping and fittings, and electrical controls cable and fittings).

b) tubing hanger systems:

- tubing hangers;
- running tools.

Detailed requirements necessary to fully define a tree system have not been included for components which do not impact the design of the core tree. For these components, additional requirements may be provided in the purchase order:

- tree mounted controls including SCM, SCMMB, sensors/instrumentation, electrical harnesses and stab plates;
- flow control module;
- retrievable choke;
- fasteners (including bolts, nuts, studs and cap screws);

- tree piping;
- structural frame;
- completion guidebase (flowbase);
- flowline connector;
- ROV panels & interfaces;
- installation tools, test tools and rig equipment;
- coatings;
- insulation.

Additional requirements may also be included for the following:

- CRA forgings;
- welding and weld overlay;
- assembly;
- FAT;
- handling, packing, shipping and storage.

Add to second-to-last paragraph ("This part of ISO 13628…")

This specification addresses scope as per API 17D but does not include the following:

- subsea trees:
  - TFL wye spool;
  - electric actuated trees.
- subsea wellheads;
- mudline suspension systems;
- drill-through mudline suspension systems;
- miscellaneous equipment.

2 Normative references

Add to clause

API 6A:2010	Specification for Wellhead and Christmas Tree Equipment
API 6AV1	Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service
API 17D:2011	Design and Operation of Subsea Production Systems – Subsea Wellhead and tree equipment

API RP 17N	Recommended Practice for Subsea Production System Reliability and Technical Risk Management
API TR 17TR7	Verification and Validation of Subsea Connectors
ASTM A370	Standard Test Methods and Definitions for Mechanical Testing of Steel Products.
DIN 3015	Fastening clamps – Block clamps
DNVGL-RP-0034	Steel forgings for subsea applications
DNVGL-RP-B202	Steel forgings for subsea applications – quality management requirements.
DNVGL-RP-O101	Technical documentation for subsea projects
ISO 8434-2	Metallic tube connections for fluid power and general use – Part 2: 37° flared connectors
SAE J514	Hydraulic Tube Fittings – Part 1: 37° Flared Fittings

3 Terms, definitions, abbreviated terms and symbols

3.2 Abbreviated terms and symbols

Add to subclause

AAV	annulus access valve
AVV	annulus vent valve
CP	cathodic protection
CIV	chemical injection valve
IWCV	intelligent well completion valve
JIC	joint industry council
LCP	lower crown plug
LP	low pressure
P&ID	process & instrumentation diagram
PCV	production choke valve
PIV	production isolation valve
PTT	pressure temperature transmitter
SCM	subsea control module
SDSS	super duplex stainless steel
SFC	steel forging class
SV	safety valve
TH	tubing hanger
THAID	tubing hanger annulus isolation device
THS	tubing head spool
TRL	technology readiness level
UCP	upper crown plug
XO	cross-over

4 Service conditions and production specification levels

4.2 Product specification levels

Replace second paragraph with

Components of equipment shall be designed and manufactured suitable for API 17D PSL 3G service.

Selected component and final tree assembly gas testing requirements shall be as specified in 6.3.

5 Common system requirements

5.1 Design and performance requirements

5.1.1 General

5.1.1.1 Product capability

Add to subclause

The equipment supplier shall provide the technology readiness level (TRL) of each major subassembly, in accordance with the requirements of API RP 17N.

5.1.2 Service conditions

5.1.2.2 Temperature ratings

5.1.2.2.1 Standard operating temperature rating

Add to subclause after third paragraph

To account for Joule-Thomson cooling, pressure-containing and pressure-controlling metal components downstream of the production choke shall be subjected to Charpy impact testing at or below -46 °C (-50 °F) per ASTM A370, with acceptance criteria for carbon and low alloy steel in accordance with DNVGL-RP-0034. Other materials should be tested at or below -46 °C (-50 °F) per ASTM A370, with acceptance criteria from the relevant industry standards for that material. This shall include the choke body and out to and including, the tree tie-in hub, flange or connector, and shall include components such as actuator bonnets, stems and bonnet bolting. This subclause does not apply to actuator components outboard of the bonnet.

5.1.2.3 Material class ratings

5.1.2.3.2 Material classes

Add to subclause

a) Pressure-containing components exposed to well bore fluids in the production flow path shall be material class HH (including and up to the XOV) as detailed below, with the exception of SDSS components as detailed in 5.1.2.3.2 d).

   1) For a vertical tree:

      − the full production bore above the PSV, up to and including the tree cap seal surface.

   2) For a horizontal tree:

      - the tubing hanger bore below the lower crown plug;

      - the tubing hanger bore between the two crown plugs;

- the tubing hanger bore above the upper crown plug, up to and including the tubing hanger running tool seal surface;

- penetrations into the tree and tubing hanger between the upper and lower crown plugs and associated isolation valve may be material class EE.

3) If specified by the purchaser in the data sheet, the annulus shall be uprated to HH as follows:

- for Annulus Configuration #1: between XOV, AWV & AVV;

- for Annulus Configuration #2: between XOV, AMV, AWV & ASV.

b) Except as modified by 5.1.2.3.2 a) 3), the annulus and other pressure-containing components within the annulus flow path shall be material class EE. All metal-to-metal sealing surfaces on pressure-containing or pressure-controlling components shall be manufactured from, or inlaid with, a corrosion-resistant alloy.

c) Chemical injection ports into the production flow path shall be material class HH out to and including the isolation, except for chemical injection porting through the tubing hanger, which shall be material class EE. All other chemical injection ports shall be material class EE out to and including the isolation.

d) SDSS is acceptable to be used for sensor flanges and housings, flow loops and small bore injection isolation valves where project specific fluid properties allow.

5.1.4 Miscellaneous design information

5.1.4.8 Cathodic protection

Add new subclause

5.1.4.8.4

Cathodic protection (CP) design shall take into account all connected items not having an independent CP system. A CP system shall be provided on the tree frame, tubing head frame and completion guidebase. The CP system of each assembly shall provide protection to one half of flying leads and well jumpers connected to that assembly. Well drain current shall be allocated to the lowermost assembly in the stack up.

Add new subclause

5.1.4.8.5

The CP system shall be designed for the design life only, with no provision for an additional period when the CP system is active prior to operation (e.g. wet storage).

Add new subclause

5.1.4.9 Electrical continuity

Designs shall ensure electrical continuity by provision of continuity bonding among assembled components of subsea equipment, which are protected by the CP system. Any components constructed of metals not compatible with applied CP levels shall be electrically isolated from the CP system, unless equipped with alternative measures such as high-performance coatings.

The anti-fouling properties of copper based alloys shall be considered ineffective where they have continuity with the CP system. In particular, copper filters on sea chests shall be isolated from the CP system.

Components constructed of alloys resistant to seawater corrosion under the anticipated service conditions (including temperature, galvanic and crevice affects), shall not require electrical continuity with the CP system but may be connected to it.

The CP system shall be designed so that vibration does not cause continuity faults.

Non-welded connections within component assemblies shall be tested to verify electrical continuity or electrical isolation as appropriate. Acceptance criteria detailed in API 17D, 5.4.8 shall be fulfilled.

Add new subclause

5.1.4.10 Monitoring

Designs shall facilitate monitoring of CP potentials of subsea equipment and anode wastage using ROV equipment. The CP monitoring location shall be identified to provide a representative potential and shall not be located immediately adjacent to an anode. This may be an uncoated patch on the tree frame which provides a contact point for an ROV CP probe.

5.1.7 Validation testing

5.1.7.1 Introduction

Add to subclause

Supplementary validation requirements are defined in Annex P and shall be applied as follows:

– For new products and substantive changes (as defined in API 17D, 5.1.7.2), validation should conform to API 17D 5.1.7 as amended by Annex P. Where validation is performed in full compliance with the recommendations of Annex P, it shall be accepted by the purchaser without further clarification.

– For existing products, if requested by the purchaser, the supplier shall undertake a gap analysis of the validation basis against the provisions of Annex P. The gap analysis shall record any deviations from the recommendations of Annex P.

5.2 Materials

5.2.1 General

Add to subclause

Materials in contact with wellbore fluids, injection fluids, control fluids, workover and drilling fluids, test fluids or seawater shall, by design, be chemically compatible with the fluids to which they are exposed.

5.2.2 Material properties

Replace second paragraph with

Carbon and low alloy steel forgings shall comply with DNVGL-RP-0034 and DNVGL-RP-B202, for the components and steel forging class (SFC) levels given in Table 38.

Material certification shall be per EN 10204 level 3.1.

Table 38 - Steel forging class level

Component	SFC level
tree/tubing head spool valve blocks	2
valve/choke bodies	2
valve/choke bonnets	1
tubing hanger body	2
tree cap	1
tree/tubing head spool connector	2

Add new subclause

5.2.6 Seal requirements

Static seals assembled and tested at the factory do not require a secondary seal element (e.g. bonnet gasket, BX gasket).

Wellhead gaskets, flowline connection gaskets and valve gate to seat seals do not require a secondary seal element.

All other metal-to-metal seals shall have a secondary seal element which may be non-metallic (e.g. production seal stabs, tubing hanger OD seals) and may be combined into one sealing assembly.

Seals shall not be considered as metal-to-metal unless the metal-to-metal sealing element has been validated independently of any non-metallic element.

Non-metallic seals made-up subsea shall have a secondary non-metallic seal element, except for:

– isolation sleeve seal to wellhead; and

– where there may be issues due to hydraulic lock or trapped pressure.

Pressure-containing seals on permanent equipment shall be metal-to-metal, except as per the examples below where non metal-to-metal seals are acceptable:

– For vertical tree systems, non-metallic seals may be used for a pressure-containing tree cap, tubing head spool isolation sleeve and tubing hanger external seals.

– For horizontal tree systems, non-metallic seals may be used for the XT isolation sleeve and the TH seal above gallery.

– Valve and choke stem primary seals may be thermoplastic. Secondary seals may be thermoplastic or encapsulated elastomeric seal.

5.4 Quality control

5.4.1 General

Add to subclause

Purchaser inspection and surveillance requirements shall be in accordance with IOGP S-561Q.

For those components not covered by this document or other purchase order requirements, equipment specific quality requirements shall comply with the supplier's written specifications and associated quality plans and inspection and test plans as agreed with the purchaser.

Add new subclause

5.4.9 Interface testing

Where tooling can be affected by coating or insulation proximity, interface verification shall be performed after coating or insulation is applied.

Add new subclause

5.7 Documentation

Documentation shall be provided by the supplier in accordance with IOGP S-561L and only the document definitions of DNVGL-RP-O101.

6 General design requirements for subsea trees and tubing hangers

6.1 General

6.1.1 Introduction

Add to subclause

Tree systems shall be designed for a 25 year life (inclusive of pre-production wet storage and post-production prior to abandonment).

6.1.2 Handling and installation

Replace second sentence of second paragraph with

All equipment assemblies shall be balanced within 1° in the as-run condition.

Add to subclause

Eccentrically loaded (unbalanced) equipment shall be balanced within 1° when made up to offset running tool.

6.1.3 Orientation and alignment

Add to subclause

The supplier shall ensure that the system tolerances enable initial orientation and alignment while simultaneously protecting seal and seal surfaces during landing, entering or mating of the equipment packages.

6.1.6 Safety

Add to list

- Pre-installation seal change out should not require working under hanging loads.
- An anti-skid or non-slip surface should be provided on all surfaces where a foothold is required during assembly, testing and pre-installation activities.

– A method should be provided to positively verify that pressure is vented in cavities after onshore and pre-deployment pressure tests, with specific focus where there is a risk of projectile launch of components (e.g. pressure trapped between TH plugs in HXT).

6.2 Tree valving

6.2.1 Master valves, vertical tree

Add to subclause

The production (injection) master valve shall be integral to the tree body and shall be actuated fail-closed.

The annulus master valve shall be integral to the tree body and shall be actuated fail-closed.

6.2.2 Master valves, horizontal tree

Add to subclause

The production (injection) master valve shall be integral to the tree body and shall be actuated fail-closed.

The annulus master valve shall be integral to the tree body and shall be actuated fail-closed.

6.2.3 Wing valves, vertical tree

Add to subclause

The production (injection) wing valve shall be integral to the production wing block or the tree body and shall be actuated fail-closed.

The annulus wing valve shall be integral to the annulus block or the tree body and shall be actuated fail-closed.

6.2.4 Wing valves, horizontal tree

Add to subclause

The production (injection) wing valve shall be integral to the production wing block or the tree body, and shall be actuated fail-closed.

The annulus wing valve shall be integral to the annulus block or the tree body, and shall be actuated fail-closed.

6.2.5 Swab closures, vertical and horizontal tree

Add to subclause

On vertical trees, provision shall be made for swab valves to be manually or hydraulically actuated in workover mode. The purchaser shall specify this in the data sheet.

6.2.6 Crossover valves

Replace subclause with

There shall be an actuated fail-closed crossover valve.

6.2.7 Tree assembly pressure closures

Add to subclause

A production isolation valve (PIV) is a valve that can isolate the production flow and is downstream of the production choke.

Provision shall be made for inclusion of either a manual or remotely actuated PIV. The purchaser shall specify in the data sheet if a PIV is required and whether it is manual or remotely actuated.

An annulus vent valve (AVV) is a valve that provides a second pressure closure (in addition to the XOV) to production flow, in case of XOV connection to the annulus side outboard of the AWV (refer to Annulus Configuration #1 in Figure 1, Figure 2 and Figure 3).

Provision shall be made for inclusion of either a manual or remotely actuated AVV. The purchaser shall specify in the data sheet if an AVV is required and whether it is manual or remotely actuated. The AVV shall be integral or bolted to the annulus wing block. Service line tie-in requirements are not covered by this specification as these are project specific defined items.

Provision shall be made for at least two closure devices between the pressure and temperature transmitter (PTT) closest to the well annulus and the production bore. Refer to Annulus Configurations #1 and #2 in Figure 1, Figure 2 and Figure 3.

6.2.8 Production (injection) and annulus flow paths

Add to subclause

Provision shall be made for two options for crossover access into the production bore. The purchaser shall specify on data sheet either:

– inboard of the PWV; or

– between the PWV and production choke valve (PCV).

Provision shall be made for two options for crossover access into the annulus bore; refer to Figure 1, Figure 2 and Figure 3. The purchaser shall specify in the data sheet either:

– between the AWV and AVV (Configuration #1); or

– inboard of the AWV (Configuration #2).

Standard tree configurations are included in 6.2.9 and replace API 17D figures as follows:

– Figure 1 (replaces API 17D Figure 1);

– Figure 2.1 (replaces API 17D Figure 2);

– Figure 2.2 (also replaces API 17D Figure 2); and

– Figure 3 (replaces API 17D Figure 3).

6.2.9 Production and annulus bore penetrations

Add to subclause

Options for production and annulus bore chemical injection penetration isolation valves [replacing Figure 4 a) and b) of API 17D] shall be as follows. The purchaser shall specify selected options in the data sheet:

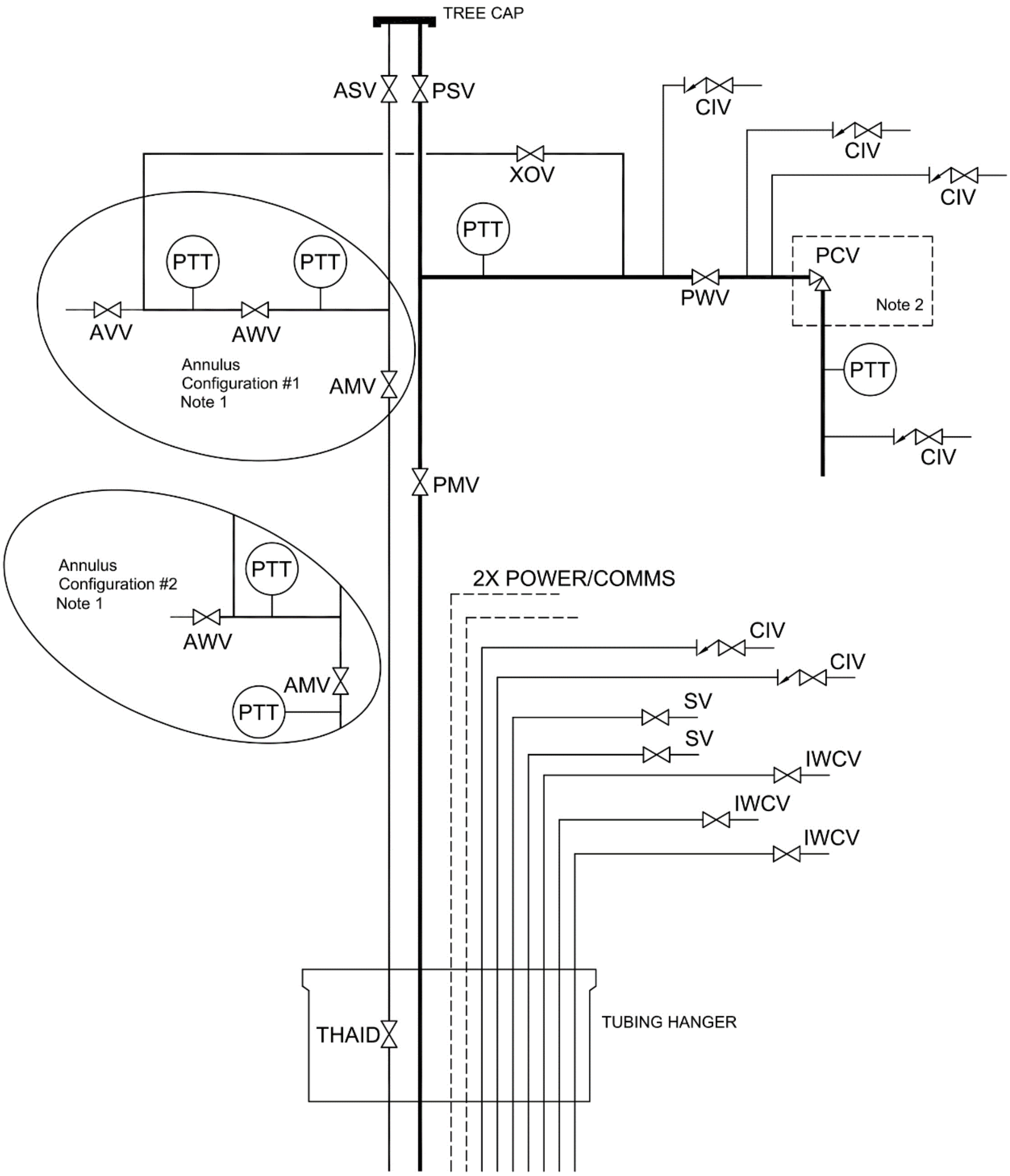
a) A single remotely actuated gate valve plus a check valve located between this valve and the bore. Both the check valve and gate valve shall be integral or bolted to the block.

b) Two remotely actuated gate valves plus a check valve located between the first valve and the bore. One gate valve shall be integral or bolted to the block. One may be panel mounted.

c) Two remotely actuated gate valves. One gate valve shall be integral or bolted to the block. One may be panel mounted.

There may be one block elbow bolted to the block between the block and isolating valve.

Replace Figure 1 with



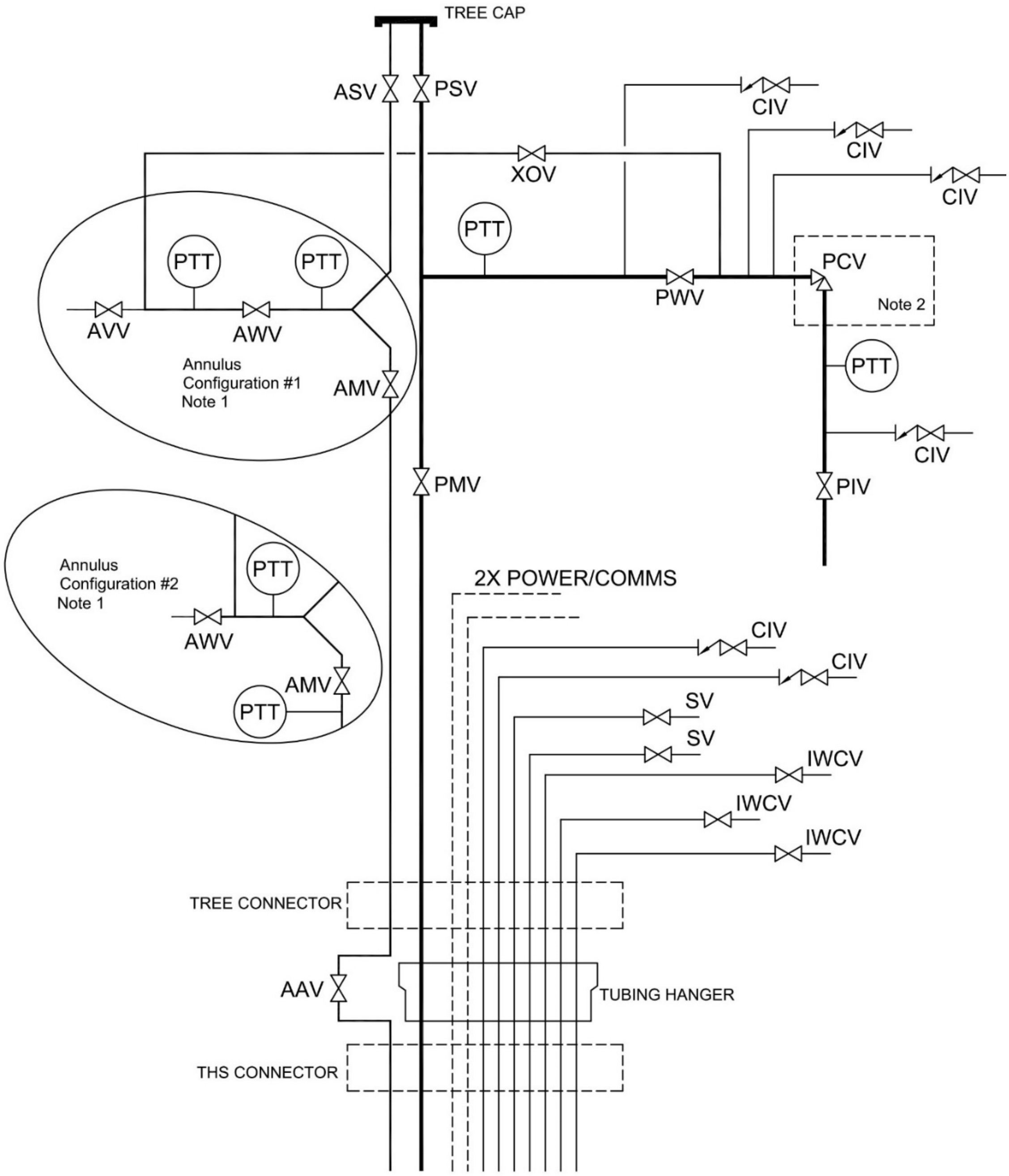
NOTE 1 Optional Annulus Configuration #1 and #2.

NOTE 2 Optional flow control module (FCM).

Figure 1 – VXT dual-bore on a subsea wellhead

NOTE Figure 1 shows fully populated options. The downhole function number may be reduced for Figure 1 (refer to 6.6.4) and alternative chemical injection isolations may be specified (refer to 6.2.9). Refer to the data sheet and project P&ID for requested type and number of functions (sensors, injection points, etc.).

Replace Figure 2 with Figure 2.1 and Figure 2.2

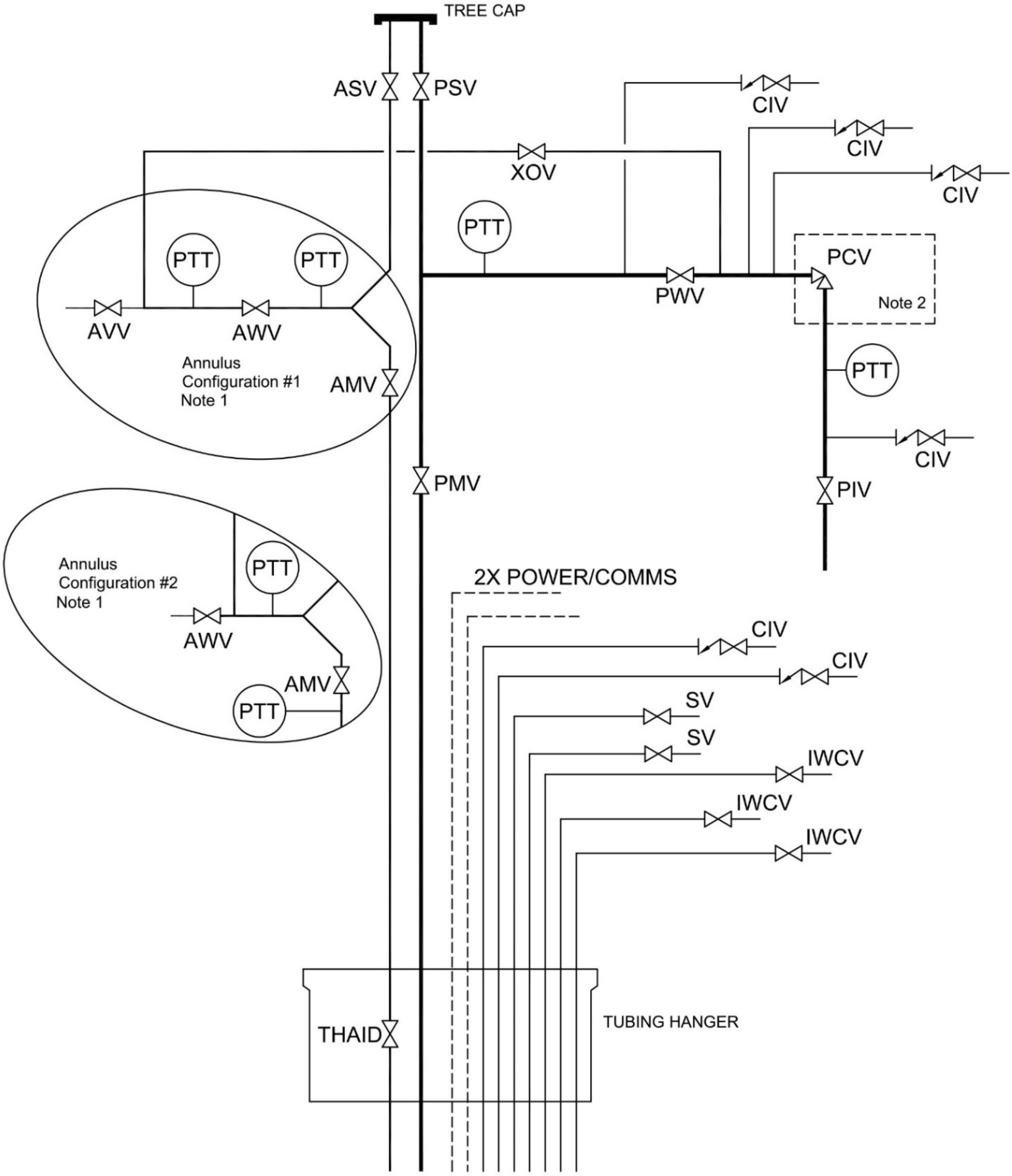


NOTE 1 Optional Annulus Configuration #1 and #2.

NOTE 2 Optional flow control module (FCM).

Figure 2.1 – VXT monobore on tubing head spool (THS)

NOTE Figure 2.1 shows fully populated options. The alternative downhole function number (refer to 6.6.4) and chemical injection isolations (refer to 6.2.9) may be specified for Figure 2.1. Refer to the data sheet and project P&ID for requested type and number of functions (sensors, injection points, etc.).



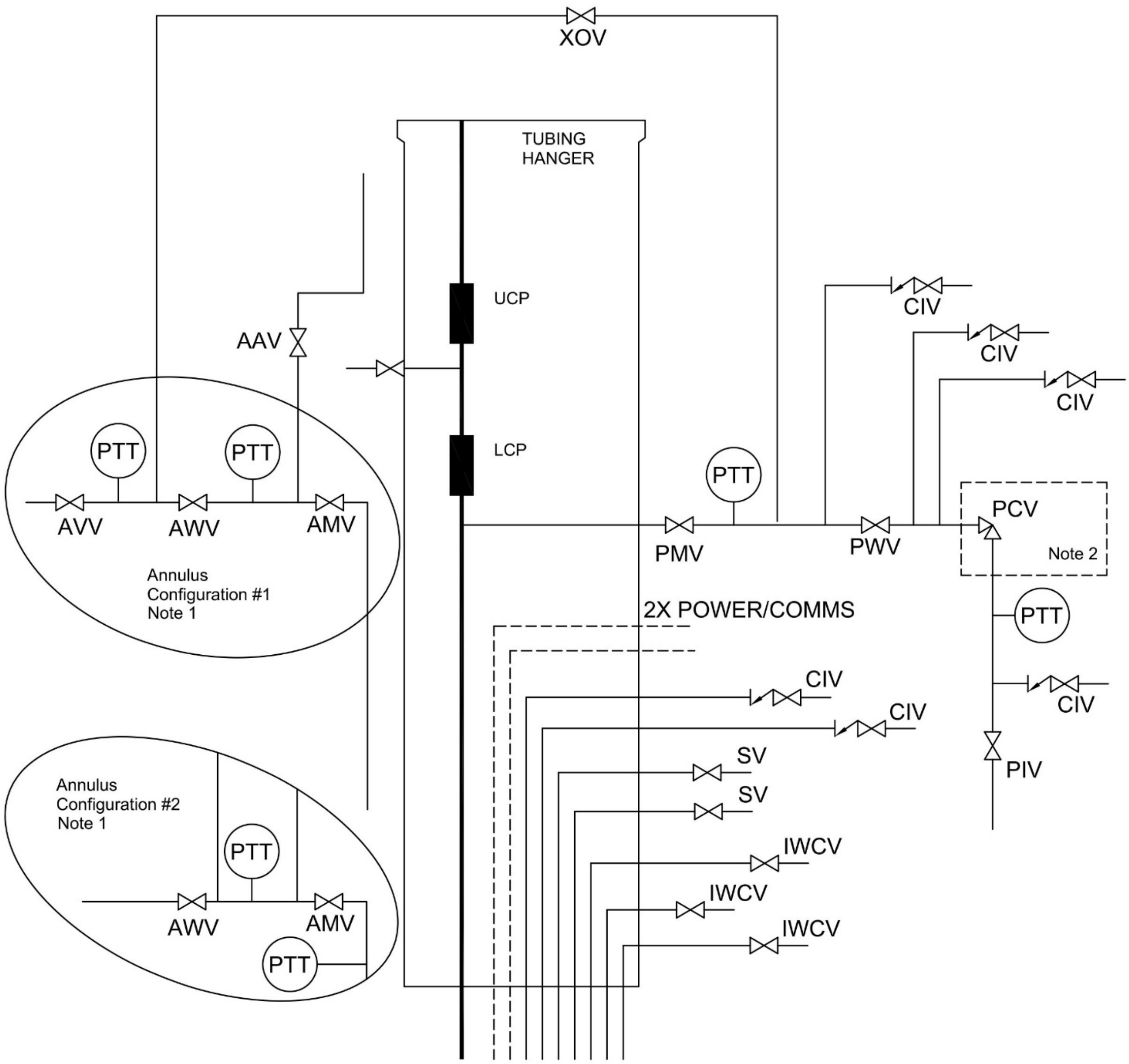
NOTE 1 Optional Annulus Configuration #1 and #2.

NOTE 2 Optional flow control module (FCM).

Figure 2.2 – VXT monobore on a subsea wellhead

NOTE Figure 2.2 shows fully populated options. The alternative chemical injection isolations may be specified (refer to 6.2.9). Refer to the data sheet and project P&ID for requested type and number of functions (sensors, injection points, etc.).

Replace Figure 3 with



NOTE 1 Optional Annulus Configuration #1 and #2.

NOTE 2 Optional flow control module (FCM).

Figure 3 – Horizontal tree on a subsea wellhead

NOTE Figure 3 shows fully populated options. The alternative chemical injection isolations may be specified (refer to 6.2.9). Refer to the data sheet and project P&ID for requested type and number of functions (sensors, injection points, etc.).

Delete Figure 4

Delete Figure 5

6.2.11 Downhole chemical-injection line penetrations

Replace subclause with

Downhole chemical injection isolation valves (replacing Figure 5 of API 17D) shall be the same as defined in 6.2.9.

6.3 Testing of subsea tree assemblies

6.3.2 Factory acceptance testing

Add to subclause

Valves, including small bore injection isolation valves (including check) and chokes, shall be PSL 3G tested in accordance with API 17D, 5.4.6. There is no requirement for:

- gas back seat testing;
- gas testing of valves in hydraulic circuits; and
- repeat of gas testing already performed at the sub-assembly level.

The tubing hanger interface with XT/THS does not require gas testing at XT/THS assembly FAT.

Production and gas injection tree final assemblies shall be submerged gas tested. The hold period for this test shall be 1 h after stabilization from submersion. Acceptance criteria shall be no bubbles during the hold period.

Add new subclause heading

6.6 Tree configurations

Add new subclause

6.6.1 Pressure and temperature sensors

XTs shall include provision for a single housing in the following locations. The purchaser shall specify the exact sensor population in the data sheet:

- between PMV and PWV;
- production bore downstream of choke;
- between AMV and AWV; or
- outboard of AWV (Configuration #1, can be out-with wing block) or inboard of AMV (Configuration #2).

Single housings shall allow for either single or dual sensor elements.

The gap between the sensor nose and the associated port shall be sized to avoid vortex induced erosion.

Add new subclause

6.6.2 Thermally induced pressure changes

Pressure integrity shall not be compromised due to thermally induced pressure changes in trapped volumes. All trapped volume analysis shall account for the various fluid properties contained therein. Areas requiring analysis shall include:

- isolated chambers used for testing secondary barriers (e.g. gasket test chambers);
- the cavity between crown plugs in HXT and the area above the swab valves but below the tree cap in a VXT;
- other areas which may be isolated (e.g. between valves on the XO loop and areas between dual seals); and
- unused, plugged off or isolated functions (e.g. unused downhole penetrations).

Add new subclause

6.6.3 Blockage avoidance

The production tree should be configured to minimize the possibility of hydrates forming by implementing the following:

- minimize the length of dead leg bores that intersect the production flow path;
- orient injection ports and gauge bores to be self-draining. Horizontal penetrations shall enter into the top half of the bore, i.e. at or above the 9 and 3 o'clock positions, to be considered self-draining.

Add new subclause

6.6.4 Chemical injection/control line provision

The tree shall include provision for the following functionality. Features not required may be blanked, or not machined.

Downhole control and chemical injection:

- For all tree types: 7 off downhole lines (valve and porting to be as a minimum, equal to 3/8 in tubing) and 2 off electrical or fibre optic lines; or
- For dual bore VXT, total number of downhole functions may be reduced; or
- For monobore VXT on THS, if specified by the purchaser in the data sheet: 9 off downhole lines (valve and porting to be as a minimum, equal to 3/8 in tubing) and 1 off electrical line.

Chemical injection:

- Hydrate inhibition lines (3/4 in valve with 3/4 in bore port minimum):
    - Between PMV and PWV;
    - Outboard of PWV or PCV.
- 2 off chemical injection lines between PWV and PCV (valve and porting to be as a minimum, equal to 1/2 in tubing).
- For subsea tree cap injection, see 7.13.1.4.

Add new subclause

6.6.5 Drill through requirement

The purchaser shall specify in the data sheet if drill through is required. When required, the HXT/THS with SCM, sensors, etc. shall be suitable for through bore drilling of bottom hole sections using a 12 1/4 in bit. During drilling or other downhole operations, protection of the HXT/THS internals, such as seal areas and landing/locking profiles for the TH, shall be provided by means of a bore protector.

Add new subclause

6.6.6 Horizontal tree systems

An access port to the cavity between the crown plugs shall be provided. The following functions and features shall be assigned to this port:

– Flow-by area when setting the upper crown plug.

– Test port to verify the sealing ability of crown plugs and potential bleeding of the cavity between the upper and lower crown plugs. Test line to be fitted with an ROV operated isolation valve.

– Test line shall be tolerant for debris with respect to bleed back of contaminated fluid during setting of plugs. Debris tolerance may be addressed using downward drilled ports in TH body and gate valves rather than needle valves.

Access to the TH gallery seal shall be provided:

– Test port to test the sealing ability of penetrators and upper and lower gallery seals.

– Pressure monitoring/potential bleeding of the cavity to be performed by ROV; online monitoring is not required.

Add new subclause

6.6.7 Insulation provision

The tree system geometry shall provide the facility for thermal insulation.

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

7.3 Threaded connections

Add to subclause

Threaded connections shall not be used on chemical injection lines for any of the permanently installed equipment. Hydrate inhibition lines not accessing tree bores may be threaded (e.g. wellhead connectors).

7.5 Studs, nuts and bolting

7.5.5 Make-up torque requirements

Add to subclause

Where coatings are used that are not specified in Annex G for bolt torque make-up, the supplier shall validate that the coefficient of friction values used are correct for the application.

For pressure-containing bolting, a process shall be employed to ensure indication of proper bolt make-up after initial assembly and again after shell test.

7.8 Tree connectors and tubing heads

7.8.1 General

7.8.1.2 Tree/tubing head spool connectors

Add to subclause

The tree/tubing head spool connector design shall include:

- provision for hydrate prevention and inhibition for connectors; the purchaser shall specify in the data sheet if this is required; and
- the ability to replace the connector gasket without retrieving the connector to the surface.

The test port shall be fitted with an ROV operated valve to provide the ability to test the connector gasket sealing. The valve shall have a pressure rating corresponding to the rating of the tree system.

7.8.2 Design

7.8.2.2 Load/capacity

Add to subclause

Performance requirements for normal, extreme and survival loads shall be in accordance with API TR 17TR7. The supplier shall provide system and connector capacities for normal, extreme and survival loads.

7.8.2.4 Secondary release

Add to subclause

The connector shall include a secondary unlock system independent of the primary system.

The secondary unlock system shall be designed such that the connector will not unlock upon exposure of the unlock line to environmental pressure.

The secondary unlock force capacity shall be the same as, or greater than, the primary unlock force.

Add new subclause

7.8.4 HXT/THS isolation sleeve

The isolation sleeve isolates the wellhead to the HXT/THS in order to enable the pressure test of the 18 ¾ in wellhead gasket with a minimal volume.

The following design requirements shall apply:

- The isolation sleeve shall provide pressure sealing above the wellhead gasket (in the spool/body) and below (in the wellhead system).
- The isolation sleeve shall be capable of withstanding HXT/THS working pressure internally and externally.

7.10 Valves, valve blocks and actuators

7.10.2 Design

7.10.2.1 Valves and valve blocks

7.10.2.1.1 General

Add to subclause

Valves, including small bore injection isolation valves (including check), shall be designed, manufactured and tested as suitable for API 6A/API 17D PSL 3G service.

Tree gate valves in production and crossover bores (excluding chemical injection valves) shall be designed to operate in accordance with the “sandy service” classification. These valves shall conform to API 6AV1 Class II.

Gate valves shall be designed to seal bi-directionally.

Large actuated gate valves (2 1/16 in nominal bore and larger) shall accommodate ROV linear override.

Penetrations shall not be permitted for the purpose of greasing, back seat testing or for testing secondary stem seals.

Stem seals shall be designed to function under all combinations of the supplier’s internal and external pressure ratings, including pressure changes experienced during deployment. Where pressure may become trapped between seals, the design shall ensure the pressure can be relieved without damaging the seals or adversely affecting valve function.

7.12 Re-entry interface

7.12.1 General

7.12.1.3 Integral or non-integral

Add to subclause

The upper hub/mandrel shall be integral to the tree spool/block.

7.12.2 Design

7.12.2.2 Re-entry interface upper connection/profile

Add to subclause

The mandrel design shall conform to the following:

– For a horizontal tree/THS, the upper mandrel shall be a 27 in H4 profile.

– H4 mandrels should be designed to accept a contingency gasket that seals in a different location than the primary gasket.

– On HXT/THS, the mandrel shall facilitate a funnel down BOP connector with swallow of 1 040 mm (41 in) below mandrel top and diameter of 1 730 mm (68 in).

7.13 Subsea tree cap

7.13.1 General

Replace subclause heading with

7.13.1.2 Non-pressure-containing tree cap (debris cap)

Add to subclause

The debris cap shall:

– cover and protect the tree/THS re-entry mandrel;

– be mechanically set and latch; and

– accommodate use of a subsea corrosion inhibitor.

If a parking spot for the debris cap is included in the tree, it shall provide a method of securing the cap to prevent movement. Load cases shall include transportation, handling, installation and accidental conditions.

Add new subclause

7.13.1.4 VXT pressure-containing tree cap and tooling

The tree system shall be designed to enable circulation through the vent lines to be certain that there is no trapped pressure before removal. This may be achieved in the tree cap or through porting into the cavities below the tree cap.

The tree cap shall be capable of wire, drill pipe or ROV installation and retrieval including sufficient overpull during installation and pulling margin during retrieval. Combinations of these methods are acceptable. The supplier shall provide normal and maximum retrieval load capacity.

Production and annulus bores shall be individually isolated by the tree cap, if specified by the purchaser in the data sheet.

7.15 Tree-guide frame

7.15.1 General

Add to subclause

The requirements of this section shall also apply to the THS guide frame/structural frame.

7.15.2 Design

7.15.2.1 Guidance and orientation

Add to subclause

The tree (or tree running tool) shall allow for ROV guidance for wire installation.

The tree/THS connector and guide funnel angles shall be designed to prevent contact with the ring gasket (where previously placed on top of the mandrel) during installation to accommodate misalignment up to 3°.

7.15.2.2 Handling

Add to subclause

The tree or separate structure shall accommodate fastening for transportation including sea-fastening.

7.15.2.3 Loads

Add to subclause

All pressure-containing components up to the second well barrier (PWV/AWV) shall be protected or designed to tolerate dropped object impact loads as per API 17A. Shipping and handling protection shall be provided.

7.17 Tree piping

7.17.1 General

Add to subclause

The requirements for this section shall also apply to piping on the completion guide base and THS.

7.17.2.3 Tree piping flowloops

Add to subclause

Crossover piping shall be a minimum of 2 in nominal schedule XXS. When crossover is drilled in the forged body, the minimum ID shall be 38,1 mm (1,50 in).

7.20 Tree-mounted hydraulic/electric/optical control interfaces

7.20.2 Design

7.20.2.2 Size and pressure

Replace first sentence with

All pipe/tubing/hose shall be 10 mm (0,375 in) diameter or larger.

7.20.2.6 Small bore tubing and connections

Add to subclause

a) For specific chemical injection requirements, refer to 7.3.
   7.20.2.6 items e) to i) also apply to chemical injection tubing.

b) Mechanical connections shall provide leak tight performance for the life of the field and shall be validated for relevant load cases including vibration from transportation, shock loads, pressure fluctuations and production loadings. Solutions may be achieved by one of the following:

   – a cone and threaded metal-to-metal axially loaded non-rotating seal face fitting with anti-vibration collet;

   – 37° cone seal (JIC) fittings, conforming to SAE J514 (ISO 8434-2);

   – twin ferrule compression fittings.

c) Rotational back-off preventative measures shall be used at all mechanical fittings. Tubing runs shall be secured to prevent rotation of the tube and unthreading of the fitting. Coned and threaded tube anti-vibration collars alone do not meet this requirement. Other anti-vibration methods may be utilized as long as they have been tested and proven to be effective at resisting backing off.

d) Tubing runs to tree connectors shall be accessible so that they can be cut by an ROV to release locked in fluid.

e) Transitions between tubing of differing wall thicknesses shall be minimized. Where required, transitions between tubing of different wall thickness shall be achieved using a purpose built transition adaptor.

f) Tubing shall be seamless.

g) Tubing joints shall be butt-welded using automated welding equipment. Tubing unions with mechanical fittings shall not be allowed except for LP return lines or bulkhead union. Socket weld connections shall not be used.

h) Tubing runs shall be supported with sufficient quantity of appropriate clamps as defined in Table 39. Clamps shall conform to DIN 3015.

i) Tubing runs shall be one piece from starting point to ending point wherever possible.

Table 39 - Maximum allowable distance between tubing clamps

Tube OD		Maximum allowable distance	
mm	in	mm	in
10 to 12	3/8 to 1/2	600	24
14 to 22	5/8 to 7/8	1000	40
25	1	1 500	60

Add new subclause

7.20.2.11 Secondary release

Where horizontal hydraulic/electric/fibre optic penetrations are required between the HXT and TH, a secondary release mechanism shall permit disengagement of the penetrator in the event of a malfunction which prevents normal (linear) retraction of the stem.

7.21 Subsea chokes and actuators

7.21.1 General

Add to subclause

Chokes shall be designed, manufactured and tested as suitable for API 6A/API 17D PSL 3G service.

Subsea chokes shall be ROV insert retrievable type, unless the choke is mounted on a retrievable package (e.g. flow control module).

The choke insert locking mechanism shall have a secondary release feature or ROV access for cutting in a clamp arrangement.

Chokes shall have dual independent methods of measuring choke position, one of which may be an external visual indicator. It shall be possible to locally override the choke position without breaking the pressure containing envelope.

9 Specific requirements – Subsea tubing hanger system

9.1 General

Add to subclause

Horizontal tree type tubing hangers shall be of dual crown plug design. For a horizontal tree type tubing hanger, the orientation feature should allow the tubing hanger to be installed from any heading.

9.2 Design

9.2.1 General

Add to subclause

The TH lock down mechanism shall be designed to prevent the TH actuator ring moving as a result of any loads acting on the TH. A secondary mechanical locking arrangement shall be incorporated into the TH actuator ring.

Impact load of the pin/key onto the helix/slot shall be checked to ensure that torque loading on the helix or strength of the pin is not exceeded. Installation loads capacity of the pin onto the helix shall be provided by the supplier.

The tubing hanger shall allow for the ability for recut of, or re-establishment of, the thread.

The tubing hanger design shall provide a method of protecting hydraulic lines and electrical through penetrations at the bottom of the tubing hanger. On vertical dual bore systems in the wellhead, provision for protection may not be possible due to the casing hanger interface, in which case protection prior to running shall be provided.

Small-bore tubing connections to the bottom of the hanger shall be designed to prevent the tubing from backing off.

Hydraulic and chemical injection lines on the hanger shall prevent water ingress if disconnected and shall maintain pressure in the downhole lines. The SCSSV line shall vent. Couplers on HXT systems may retain pressure when not mated to allow pre-charge of SCSSV valve for installation/circulation purposes.

The running profile rated load capacity shall be the same or greater than the production tubing connection load capacity. The supplier shall provide running profile rated load capacity.

9.2.2 Loads

Add to subclause

The TH should resist rotational torque of 47 500 Nm (35 000 ft lbs). This is to accommodate built up torque when setting the hanger, especially in deviated wells. The supplier shall provide the rated rotational load capacity.

9.2.9 SCSSV and chemical-injection control-line stab design

Add to subclause

For a VXT, where a spring loaded relief valve is utilized on the SCSSV line, it shall not maintain a pressure within the SCSSV circuit of more than 6,9 bar (100 psi) above ambient when vented to sea.

It shall be possible to lock open the SCSSV during installation of the TH.

9.2.10 Miscellaneous tools

Add new subclause

9.2.10.1 HXT TH isolation sleeve

A TH isolation sleeve shall provide isolation of the production outlet to allow circulation of the production string during running/retrieval.

The following design requirements shall apply:

- TH isolation sleeve shall be locked in place; and
- TH isolation sleeve rated working pressure shall be the same as the tree system rated working pressure.

Add new subclause

9.2.10.2 HXT TH protection sleeve

During downhole operations, adequate protection of the TH internals such as seal areas and landing/locking profiles shall be provided by means of a wire-line deployed protection sleeve.

This shall allow free passage of subsequent wire-line tool strings with smooth transitions to the bore. The protection sleeve shall be suspended and locked in the TH.

Add new subclause

9.2.11 Tubing hanger annulus isolation device

The tubing hanger annulus isolation device (THAID) is a temporary barrier element, replacing the annulus wireline plug during well construction and workover for tubing hangers installed in a wellhead.

The THAID shall:

- provide isolation of the annulus flowpath through the tubing hanger and shall seal against full RWP of the tubing hanger from above and below in the closed position;
- be operable closed to open with differential pressure of RWP from below, without compromising sealing capability;
- be operable by an ROV or by the workover control system. The THAID shall not be operable by the production control system. The THAID shall be operable during land out of the tubing hanger with BOP installed on wellhead, and with tree installed on wellhead;
- be fail as-is or fail close. Application of pressure from above or below shall not result in unintentional operation;
- have a secondary actuation method;
- be capable of remaining open for the majority of its life and still function at the end of its design life.

The annulus porting through the tubing hanger shall have a minimum flow-by area of 137,16 mm^2 (1 in^2), with the THAID in the fully open position.

Add new annex

Annex P (new)
(informative)
Validation testing

P.1 Introduction

This annex has been prepared to offer guidance with respect to validation testing. It addresses clarifications and informative additions to API 17D validation testing and should be read concurrently with API 17D, 5.1.7. The intent is to provide a preferred interpretation of API 17D validation testing requirements.

The stated requirements are value adding practice for validation of new products or re-validation of existing products due to a substantive change. The requirements of Annex P should not be used as justification for re-validation of existing products.

P.2 General

Pressure cycles, temperature cycles and endurance cycles should be performed as specified in API 17D, in a cumulative test using one product without changing any seals or components.

Grease, sealant or lubricant should not be used to mask defects in sealing systems. Lubricants can be used to aid in the assembly and break-in period of the equipment.

In the event of failure during validation testing, resulting in modification to fit, form or function, or replacement of components, testing should restart from a point in the test sequence which ensures that affected components are subjected to the full test sequence.

P.3 Temperature cycling tests

Objective evidence should not be utilized as an alternative to testing.

P.4 Life-cycle/endurance testing

P.4.1 General

All valves, seals and other components whose operation may be affected by external hydrostatic pressure should be tested in a hyperbaric chamber. If a component does not fit in a hyperbaric chamber, the test can be performed in a suitable test fixture simulating hyperbaric pressure.

Validation testing should include accurate simulations of all design loads and service conditions to the extent practical. The source of these loads can be either from environmental effects or other interfacing equipment.

Except where explicitly stated in the following clauses, validation should be performed in a cumulative test on one product without:

- maintenance;
- addition of a lubricant or sealant;
- changing of any seals or components; or
- disassembly for the duration of the testing.

Pressure and temperature stabilization requirements should be in accordance with API 6A, F.1.10.

P.4.2 Seals

Primary seals exposed to well bore and associated secondary seals, either metal-to-metal or non-metallic, should be validated in accordance with API 17D Table 3 as seals “exposed to well bore in production”.

Validation should also follow the intent of the API 6A, Annex F PR2 sequence as follows. This will satisfy the 200 pressure/load cycle tests and 3 temperature cycle tests of API 17D, Table 3.

a) Before performing all testing described below, the seal should undergo FAT including a gas test performed at room temperature. Test pressure is rated working pressure and the hold period is 15 minutes.

b) Pressure and temperature cycles per API 6A, F.1.11.

c) 200 pressure cycles at room temperature per API 17D, 5.1.7.4.

d) Steps b) and c) can be performed in either order.

e) Gas test performed at room temperature. Test pressure is rated working pressure and the hold period is 15 minutes.

f) Seals should be validated with hyperbaric testing in accordance with API 17D, Annex L where the seal is exposed to external hydrostatic pressure, and the seal, surrounding geometry or tolerances are asymmetrical.

Acceptance criteria for seals should be in accordance with API 17D, 5.4.6.2.3 for PSL 3G equipment. Acceptance criteria for minimum/maximum temperature tests should be in accordance with API 6A, F.1.6.3 c). Seals that are identical in function but different in size, shape or configuration should be validated separately.

Bi-directional seals should follow the full test sequence from both directions if the seal in question will be exposed to pressure variations from both directions by design. Where the bi-directional seal, surrounding geometry and tolerances are symmetrical, the full test sequence may be performed in one direction only.

Unidirectional seals should be validated from the primary pressure direction. At the beginning and the end of the validation test, it should be proven that the seal relieves pressure from the reverse direction, if this function is required by the design.

P.4.3 Subsea valves

P.4.3.1 General

The following testing requirements apply to all subsea valves, both manual and actuated, that are exposed to wellbore fluids.

All valve validation testing should be conducted on a single valve without:

- maintenance;
- addition of lubricant or sealant; or
- replacement of any seals or components for the duration of the testing.

The valve should not be disassembled for any reason during testing.

The valve and hydraulic actuator assembly performance limits should be validated in accordance with criteria given in API 17D, 7.10.4.1.3.

Pressure testing should be conducted in one direction only and should be performed in the expected direction of flow. This direction should be consistent throughout all testing, with the exception of final bi-directional low-pressure seat test for gate valves as specified in API 6A, F.2.3.3.15 and FAT gas seat test as specified in API 17D, 5.4.6.2.3.

Secondary stem seals should be independently tested in accordance with API 17D, 5.1.7.2.

Valve validation testing should meet API 17D requirements as follows (see Table P.1):

a) Before performing all testing described below, the valve should undergo FAT per API 17D, 5.4.6.

b) PR2 sequence, as per API 6A, F.2.3 for PR2 valves. This will satisfy 200 of the 600 endurance cycles and the 3 temperature cycles detailed in Table 3.

c) 200 hyperbaric cycles, in accordance with API 17D, Annex L and 7.10.4.1.3. This will satisfy the 200 pressure/load cycles and 200 of the 600 endurance cycles detailed in API 17D, Table 3.

d) 200 endurance cycles, as per API 6A, F.2.2.2.2 except that the number of cycles should be 200. This will complete the 600 endurance cycles detailed in API 17D, Table 3.

e) After performing all testing described above, the valve should undergo a gas body and gas seat test in accordance with API 17D, 5.4.6.2.2 and 5.4.6.2.3, with acceptance criteria as stated below.

Steps b), c), and d) can be performed in any order, however each step should be fully completed before progressing to the next.

Acceptance criteria for all gas stages of validation should be in accordance with API 17D, 5.4.6.2.3 for PSL 3G equipment and for pressure-containing seals, and API 6A, F.1.6.3 for pressure-controlling seals.

For hyperbaric testing in accordance with API 17D, Annex L, there is no requirement to maintain the test medium at 4 °C throughout the test.

The testing described in P.4.3 will satisfy the validation requirements for valve seals including those of P.4.2.

P.4.3.2 Gate valves

Tree gate valves in production and crossover bores should be validated for Class II sandy service in accordance with API 6AV1. It is not required that the valve used for P.4.3.1 should be the same valve used for API 6AV1 validation.

P.4.3.3 Check valves

For check valves without any penetrations running through the body wall, communicating wellbore and the environment, 200 endurance cycles can be performed in lieu of the 200 hyperbaric cycles.

P.4.3.4 Needle valves

The validation testing of needle valves should be performed in accordance with the requirements of P.4.3.1. There are no additional validation requirements.

P.4.4 Subsea valve actuators

P.4.4.1 General

The following general requirements should apply to valve actuators, both hydraulic and manually operated.

The actuator may be validated concurrently with valve validation testing or with a test valve or fixture that provides the functionality and output forces/torques required of a production-style valve.

When size restrictions prevent hyperbaric validation testing of the valve and actuator simultaneously, the actuator should be coupled with a dummy valve that replicates the valve functional loading, for all hyperbaric validation test conditions.

Valve actuator validation testing should meet API 17D requirements as follows (see Table P.1):

a) PR2 sequence, in accordance with API 6A, F.2.5 for PR2 actuators. This will satisfy 200 of the 600 endurance cycles and the 3 temperature cycles required by API 17D Table 3.

b) 200 hyperbaric cycles, in accordance with API 17D, Annex L. This will satisfy the 200 pressure/load cycles and 200 of the 600 endurance cycles required by API 17D, Table 3.

c) 200 endurance cycles, as per API 6A, F.2.5 step b) except the number of cycles should be 200. This will complete the 600 endurance cycles required by API 17D, Table 3.

d) Steps a), b) and c) can be performed in any order however each step should be fully completed before progressing to the next.

The valve position indicator should be verified such that indicator shows the true position of valve flow path.

P.4.4.2 Hydraulic valve actuators

No seal replacement, actuator redress, or disassembly should be allowed during testing.

Before testing in P.4.4.1, the actuator should undergo FAT including hydrotests at 20 % and 100 % of the RWP of the actuator, as described in API 17D, 7.10.4.2.3 c).

P.4.4.3 Valve actuators with ROV linear override

The force required and linear travel to fully stroke and override the valve, determined with calculations and confirmed during testing, should be measured and recorded before and after completion of testing in P.4.4.1. Force measurement should be conducted under atmospheric conditions and the following data recorded:

a) operating force required to stroke the valve from its failed position (i.e. compress the spring) with zero pressure in bore;

b) operating force required to fully open a fail-closed valve with RWP pressure differential across the gate;

c) operating force required to fully close a fail-open valve with RWP in the valve bore and body.

Valve signatures may be used in lieu of direct force measurement where they provide equivalent data to P.4.4.3 a), b) and c).

Either during validation testing or as a separate test, the maximum operating force (force determined by the supplier that can be applied in the fully stroked position, without damage or deformation to any valve component that would impair or affect performance) should be applied.

P.4.4.5 Valve actuators with ROV rotary override and manual valve actuators

Torque required, number of turns and direction of rotation to operate should be measured and recorded before and after completion of testing in P.4.4.1. Measurement should be conducted under atmospheric conditions as follows:

a) operating torque required to stroke the valve fully open and closed with zero pressure in the bore;

b) operating torque required to stroke the valve fully open, starting from the closed position with RWP differential across the gate;

c) operating torque required to stroke the valve fully closed from the open position with RWP in the valve bore and body;

d) performance of the open/close indicator should be validated against the number of turns;

e) number of turns and direction to operate.

Either during validation testing or as a separate test, the maximum operating torque (maximum rated torque determined by supplier that can be applied in fully open and fully closed positions, without damage or deformation to any valve component that would impair or affect performance) should be applied.

P.4.5 Tubing hanger annulus isolation device

Annulus isolation device validation testing should meet the following:

a) Individual seals should be validated by completion of the pressure and temperature sequence cycling described in API 6A, F.1.11. This test should be performed on individual seals in a test fixture, but can be performed in the assembled annulus isolation device where appropriate test ports are provided.

b) The annulus isolation device assembly should be validated by completion of the following test sequence, based on API 6A, Annex F PR2 requirements. Seals may be changed out prior to the start of this test sequence.

   1) Before performing all testing described below, the device should undergo FAT including a gas body and gas seat test per API 17D, 5.4.6.2.2 and 5.4.6.2.3.

   2) Force or torque measurement, in accordance with API 6A, F.2.3.3.1, except that the measurement should be conducted twice; once with 100 % RWP pressure differential from below and once from above. The test fluid may be liquid.

   3) Dynamic test cycles, in accordance with API 6A, F.2.3.3.2, except that the reduced number of cycles and temperature should be maintained at 4 °C ± 1 °C throughout testing. A cycle is defined as the device stroking from fully closed, to fully open, to fully closed. Dynamic cycles with both liquid and gas test mediums should be performed. With a liquid test medium, 20 cycles should be performed with 100 % RWP pressure differential from below and 20 cycles performed with 100 % RWP pressure differential from above. With a gas test medium, 3 cycles should be performed with 100 % RWP pressure differential from below.

   4) API 6A, F.2.3.3.3 and F.2.3.3.4 should not be performed.

   5) Gas seat test, in accordance with API 6A, F.2.3.3.5, except that it should be performed twice, with the pressure differential from both above and below, and temperature maintained at 4 °C ± 1 °C.

   6) Low-pressure seat test, in accordance with API 6A, F.2.3.3.6, except that it should be performed twice, with the pressure differential from both above and below, and temperature maintained at 4 °C ± 1 °C.

   7) API 6A, F.2.3.3.7 through F.2.3.3.10 should not be performed.

   8) Body pressure/temperature cycles, in accordance with API 6A, F.2.3.3.11, except that steps F.1.11.3 a) through o), should be performed, the device should remain closed throughout, and the test pressure should be applied from below.

   9) Body pressure holding test, as per API 6A, F.2.3.3.12, except that the temperature should be maintained at 4 °C ± 1 °C.

   10) Gas seat test, in accordance with API 6A, F.2.3.3.13, except that it should be performed twice, with the pressure differential from both above and below, and temperature maintained at 4 °C ± 1 °C.

11) API 6A, F.2.3.3.14 should not be performed.

12) Low-pressure seat test, in accordance with API 6A, F.2.3.3.15, except that it should be performed twice with pressure differential from both above and below and temperature maintained at 4 °C ± 1 °C.

13) Force or torque measurement, in accordance with API 6A, F.2.3.3.16, except that the measurement should be conducted twice: once with 100 % RWP pressure differential from below, and once from above. The test fluid may be liquid.

All seals or other components whose operation may be affected by external hydrostatic pressure should be tested in a hyperbaric chamber or suitable test fixture simulating hyperbaric pressure. It should be demonstrated that the annulus isolation device, including the actuating mechanism, will function at the design water depth.

Acceptance criteria for all gas stages of validation should be in accordance with API 17D, 5.4.6.2.3 PSL 3G for equipment for pressure-containing seals, and in accordance with API 6A, F.1.6.3 for pressure-controlling seals.

P.4.6 Chokes

All choke valve validation testing should be conducted on the same valve, without:

- maintenance;
- addition of lubricant or sealant; or
- replacement of any seals or components for the duration of the testing.

The choke valve should not be disassembled for any reason during testing.

The choke valve validation testing should meet API 17D requirements as follows (see Table P.2):

a) Before performing all testing described below, the choke valve should undergo FAT including a gas body test in accordance with API 17D, 5.4.6.2.2.

b) PR2 sequence, in accordance with API 6A, F.2.7 for PR2 chokes. This will satisfy 200 of the 500 endurance cycles and the 3 temperature cycles required by API 17D, Table 3.

c) 200 hyperbaric cycles, in accordance with API 17D, Annex L. This will satisfy the 200 pressure/load cycles and 200 of the 500 endurance cycles required by API 17D, Table 3.

d) 100 endurance cycles in accordance with API 6A, F.2.7.4 except that the number of cycles should be 100. This will complete the 500 endurance cycles required by API 17D, Table 3.

e) After performing all testing described above, choke valve should undergo a gas body test in accordance with API 17D, 5.4.6.2.2.

P.4.7 Choke actuators

The actuator may be validated concurrently with choke validation testing or with a test choke or fixture that provides the functionality and output forces required of a production-style choke.

Choke actuator seals should be tested in accordance with API 17D. The choke position indicator should be verified for accurate position reading. Both mechanical and electrical (if applicable) indicator function should be verified.

As used in the following clauses the term “endurance cycle” follows the definition for PR2 actuators (open-close-open) and “choke actuator endurance cycle” follows the definition of API 17D, Table 3 Note e) (full-open to full-close or full-close to full-open).

Choke actuator validation testing should meet API 17D requirements as follows (see Table P.3):

a) Before performing all testing described below, the actuator should undergo FAT including hydrotest at 20 % and 100 % of the RWP of the actuator, as described in 7.21.4.2.2.

b) PR2 sequence, in accordance with API 6A, F.2.5 for PR2 actuators. This will satisfy 400 of the 1 000 choke actuator endurance cycles and the 3 temperature cycles required by Table 3.

c) 200 hyperbaric cycles, in accordance with API 17D, Annex L. This will satisfy the 200 pressure/load cycles and 400 of the 1 000 choke actuator endurance cycles required by API 17D, Table 3.

d) 100 endurance cycles in accordance with API 6A, F.2.5 b), except that the number of cycles should be 100. This will satisfy 200 of the 1 000 choke actuator endurance cycles required by API 17D, Table 3.

e) After performing all testing described above, the actuator should undergo FAT including hydrotest at 20 % and 100 % of the RWP of the actuator, as described in API 17D, 7.21.4.2.2.

P.5 Product family validation

Validation of product family by API 17D scaling methods should not be used to meet equipment validation testing requirements except for the sand slurry test, if the valves are members of a product family, as defined in API 6AV1, and have the same geometric shape at the body cavity, gate, seat and seals.

P.6 Documentation

All validation test records should be continuous for both pressure and temperature tests (i.e. no breaks in the recording/logging of any of the test data).

Validation testing documentation should include the following:

– validation test procedure;

– test charts;

– photographs and/or video of testing/equipment;

– signatures of testing technicians and witnesses;

– assembly and component traceability (assembly number, part numbers, revisions, serial numbers, material, weld non-destructive examination, etc.);

– general assembly drawings of all equipment, including test equipment;

– stack-up drawing of test setup;

– validation testing report; and

– dimensional report of all critical parts before and after testing.

Table P.1 – Interpretation of API 17D Table 3 cycles for valves and valve actuators

API 17D Table 3 requirement for valves and actuators		Pressure/load cycling test	Temperature cycling test	Endurance cycling test (total cumulative cycles)
		200	**3**	**600**
	to be satisfied by:			
Gate valves Needle valves	**Validation test**	API 6A F.2.3 Design validation for PR2 valves 200 cycles + 3 temperature cycles	API 17D Annex L Hyperbaric testing 200 cycles	API 6A F.2.2.2.2.1 Modified endurance cycling test 200 cycles
	Number of API 17D Table 3 cycles accumulated for each test	200 endurance cycles 3 temperature cycles	200 endurance cycles 200 pressure/load cycles	200 endurance cycles
Check valves	**Validation test**	API 6A F.2.3 Design validation for PR2 valves 200 cycles + 3 temperature cycles	API 17D Annex L Hyperbaric testing 200 cycles OR (if design is not affected by hyperbaric pressure) API 6A F.2.2.2.2.2 Modified endurance cycling test 200 cycles	API 6A F.2.2.2.2.2 Modified endurance cycling test 200 cycles
	Number of API 17D Table 3 cycles accumulated for each test	200 endurance cycles 3 temperature cycles	200 endurance cycles 200 pressure/load cycles	200 endurance cycles
Valve actuators	**Validation test**	API 6A F.2.5 Design validation for PR2 actuators 200 cycles + 3 temperature cycles	API 17D Annex L Hyperbaric testing 200 cycles	API 6A F.2.5 b) Modified endurance cycling test 200 cycles
	Number of API 17D Table 3 cycles accumulated for each test	200 endurance cycles 3 temperature cycles	200 endurance cycles 200 pressure/load cycles	200 endurance cycles

Table P.2 – Interpretation of API 17D Table 3 cycles for choke valves

<table>
<tr><th colspan="2" rowspan="2">API 17D Table 3 requirement for choke valves</th><th>Pressure/load cycling test</th><th>Temperature cycling test</th><th>Endurance cycling test (total cumulative cycles)</th></tr>
<tr><th>200</th><th>3</th><th>500</th></tr>
<tr><td colspan="5">to be satisfied by:</td></tr>
<tr><td rowspan="2">Choke valves</td><td>Validation test</td><td>API 6A F.2.7
Design validation for PR2 chokes
200 cycles + 3 temperature cycles</td><td>API 17D Annex L
Hyperbaric testing
200 cycles</td><td>API 6A F.2.7.4
Modified endurance cycling test
100 cycles</td></tr>
<tr><td>Number of API 17D Table 3 cycles accumulated for each test</td><td>200 endurance cycles
3 temperature cycles</td><td>200 endurance cycles
200 pressure/load cycles</td><td>100 endurance cycles</td></tr>
</table>

Table P.3 – Interpretation of API 17D Table 3 cycles for choke valve actuators

<table>
<tr><th colspan="2" rowspan="2">API 17D Table 3 requirement for choke valve actuators</th><th>Pressure/load cycling test</th><th>Temperature cycling test</th><th>Endurance cycling test (total cumulative cycles)</th></tr>
<tr><th>200</th><th>3</th><th>1000
(choke actuator endurance cycles)</th></tr>
<tr><td colspan="5">to be satisfied by:</td></tr>
<tr><td rowspan="3">Choke valve actuators</td><td>Validation test</td><td>API 6A F.2.5
Design validation for PR2 actuators
200 cycles + 3 temperature cycles</td><td>API 17D Annex L
Hyperbaric testing
200 cycles</td><td>API 6A F.2.5.b
Modified endurance cycling test
100 cycles</td></tr>
<tr><td>Number of API 17D Table 3 cycles accumulated for each test</td><td>400 choke actuator endurance cycles
3 temperature cycles</td><td>400 choke actuator endurance cycles
200 pressure/load cycles</td><td>200 choke actuator endurance cycles</td></tr>
<tr><td>Additional testing</td><td colspan="3">Further endurance cycles as per API 6A F.2.5.b except the number of cycles should be performed to reach a cumulative 1 million actuator steps</td></tr>
</table>

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This specification supplements API 17D:2011 Design & Operation of Subsea Production Systems – Subsea Wellhead and Tree Equipment, referring sequentially to the same clause.