International Association of Oil & Gas Producers

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Supplementary Specification to API Specification 17D Subsea Wellhead and Tree Equipment

JIP33
JOINT INDUSTRY PROGRAMME

Revision history

VERSION	DATE	PURPOSE
3.1	November 2022	Issued for Public Review
3.0	December 2018	Third Edition
2.0	November 2016	Second Edition
1.0	September 2016	First Edition

Acknowledgements

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

Foreword

This specification was prepared under Joint Industry Programme 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). Companies from the IOGP membership participated in developing this specification to leverage and improve industry level standardization 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, resulting in a common and jointly agreed specification, building on recognized industry and international standards.

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 CPC vision is to standardize specifications for global procurement for equipment and packages. JIP33 provides the oil and gas sector with the opportunity to move from internally to externally focused standardization initiatives and provide step change benefits in the sector's capital projects performance.

This specification has been developed in consultation with a broad user and supplier base to realize benefits from standardization and achieve significant project and schedule cost reductions.

The JIP33 work groups performed their activities in accordance with IOGP's Competition Law Guidelines (November 2020).

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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 Specification 17D, Third Edition, October 2021, Specification for Subsea Wellhead and Tree Equipment for application in the petroleum and natural gas industries.

This 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 Specification

This specification is to be applied in conjunction with the supporting procurement data sheet, information requirements specification (IRS) and quality requirements specification (QRS) as follows.

IOGP S-561: Supplementary Specification to API Specification 17D Subsea Wellhead and Tree Equipment

This specification defines the technical requirements for the supply of the equipment and is written as an overlay to API Specification 17D, following the API Specification 17D clause structure. Clauses from API Specification 17D not amended by this specification apply as written to the extent applicable to the scope of supply.

Modifications to API Specification 17D 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: Procurement Data Sheet for Subsea Trees (API)

The procurement data sheet defines application specific requirements, attributes and options specified by the purchaser for the supply of equipment to the technical specification. The procurement data sheet may also include fields for supplier provided information attributes subject to purchaser's technical evaluation. Additional purchaser supplied documents may also be incorporated or referenced in the procurement data sheet to define scope and technical requirements for enquiry and purchase of the equipment.

IOGP S-561L: Information Requirements for Subsea Trees (API)

The IRS defines the information requirements, including contents, format, timing and purpose to be provided by the supplier. It may also define specific conditions which invoke information requirements.

IOGP S-561Q: Quality Requirements for Subsea Trees (API)

The QRS defines quality management system requirements and the proposed extent of purchaser conformity assessment activities for the scope of supply. Purchaser conformity assessment activities are defined through the selection of one of four generic conformity assessment system (CAS) levels on the basis of evaluation of the associated service and supply chain risks. The applicable CAS level is specified by the purchaser in the data sheet or in the purchase order.

The terminology used within this specification and the supporting procurement data sheet, IRS and QRS follows that of API Specification 17D and is in accordance with ISO/IEC Directives, Part 2 as appropriate.

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

The order of precedence (highest authority listed first) of the documents shall be:

a) regulatory requirements;

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

c) purchaser defined requirements (procurement data sheet, IRS, QRS);

d) this specification;

e) API Specification 17D.

2 Normative References

Add to section

API Recommended Practice 17N, *Recommended Practice on Subsea Production System Reliability, Technical Risk, and Integrity Management*

ASTM A370, *Standard Test Methods and Definitions for Mechanical Testing of Steel Products.*

DIN 3015-1, *Fastening clamps – Block clamps*

DNVGL-RP-0034, *Steel forgings for subsea applications - technical requirements*

DNVGL-RP-B202, *Steel forgings for subsea applications - quality management requirements*

DNVGL-RP-O101, *Technical documentation for subsea projects*

EN 10204, *Metallic products —Types of inspection documents*

ISO 8434-2, *Metallic tube connections for fluid power and general use — Part 2: 37° flared connectors*

SAE J514, *Metallic Connections for Fluid Power and General Use - Part 1: 37 Degree Flared Fittings*

3 Terms, Definitions, Acronyms, Abbreviations, and Symbols

3.1 Terms and Definitions

Add new term 3.1.77

3.1.77
tubing hanger annulus isolation device
THAID
Mechanically or hydraulically actuated temporary barrier element in the annulus flow path of a tubing hanger, replacing the annulus wireline plug during well construction and workover for tubing hangers installed in a wellhead.

Add new term 3.1.78

3.1.78
annulus vent valve
AVV
Valve that provides, in addition to the XOV, a second pressure closure to production flow and that is present when the XOV connection to the annulus side is outboard of the AWV.

NOTE Refer to annulus Configuration #1 in Figure 1, Figure 2 and Figure 3.

Add new term 3.1.79

3.1.79
production isolation valve
PIV
Valve that can isolate the production flow and that is downstream of the production choke.

Add new term 3.1.80

3.1.80
provision
Status or condition of a standard design being such that a particular feature can be included as an option, but that feature may only be included in any particular configuration if that option is specified in the data sheet.

3.2 Acronym, Abbreviations, and Symbols

Add to section

AVV	annulus vent valve
BPT	between plug test (alternatively known as cavity above lower plug or cavity below upper plug)
CP	cathodic protection
CIV	chemical injection valve
JIC	Joint Industry Council (fittings)
LCP	lower crown plug
LP	low pressure
PIV	production isolation valve (alternatively known as flowline isolation valve, pipeline isolation valve, FIV or FLIV)
PTT	pressure temperature transducer
SCM	subsea control module
SDSS	super duplex stainless steel
TH	tubing hanger
THAID	tubing hanger annulus isolation device
TRL	technology readiness level
UCP	upper crown plug
SCMMB	subsea control module mounting base

4 Application, Service Conditions, and Production Specification Levels

4.1 Application

Delete list item b)

Delete list item c)

Delete list item d)

Add new NOTE 3

NOTE 3 Additional requirements defined by the purchaser (beyond the requirements contained in this specification and associated data sheet selections) are necessary to fully specify the complete subsea tree system design beyond the aspects of tree system design that are defined by supplier standard designs/configurations.

Add after NOTE 2

This specification covers tree systems configured for a single jumper connection for production (injection) and annulus service, used in a satellite or cluster field configuration, configured for guidelineless installation and designed for operating at water depths up to 10,000 ft (3000 m).

Add to subsection

The scope of this specification excludes the following:

— all-electric subsea trees (i.e. trees without hydraulics);

— subsea wellheads;

— mudline suspension systems;

— drill-through mudline suspension systems.

4.3 Product Specification Levels

Add after third paragraph

Production and gas injection tree components exposed to retained fluids shall be PSL 3G.

Add after third paragraph

Water injection tree components shall be specified as either PSL 3 or PSL 3G.

5 Common System Requirements

5.1 Design and Performance Requirements

5.1.1 General

5.1.1.1 Product Capability

Add to subsection

If specified, components, equipment and assemblies that can be defined as new or modified technology shall have a TRL in accordance with the requirements of API 17N.

5.1.1.3 Thermal Integrity

In list item b), replace "the minimum transitional operating temperature" with

46 °C (-50 °F) as per ASTM A370

Add to subsection

Transitional low-temperature effects shall be addressed for pressure-containing and pressure-controlling components downstream of the choke (e.g. the choke body, components out to and including the tree tie-in hub, flange or connector, and components such as valve bonnets, stems and bonnet bolting), excluding actuator or manual operator components outboard of the bonnet.

Add to subsection

Transitional low-temperature effects shall be addressed for metallic pressure-containing and pressure-controlling components using either the method described in 5.1.1.3 a) or the one described in 5.1.1.3 b).

Add to subsection

Transitional low-temperature effects shall be addressed for non-metallic components using either the method described in 5.1.1.3 a) or the one described in 5.1.1.3 c).

Add to subsection

Where the method described in 5.1.1.3 b) is used for carbon and low alloy steel, Charpy validation acceptance criteria shall be in accordance with DNV-RP-0034.

Add to subsection

Where the method described in 5.1.1.3 b) is used for metallic material other than carbon and low-alloy steel, Charpy validation acceptance criteria shall be from the applicable industry standards for that material.

5.1.1.4 Materials

Add to subsection

Pressure-containing components exposed to well bore fluids in the production flow path inboard of the isolation valve on tree chemical injection ports and below the PSV or LCP shall be material class HH, except for penetrations into the tree and tubing hanger between the UCP and LCP and associated isolation valve.

Add to subsection

For a vertical tree, material class HH shall be used for the full production bore above the PSV, up to and including the tree cap seal surface when the tree cap isolates the production bore or for the full production bore above the PSV, up to and including the production bore re-entry stab sealing surface when the tree cap does not isolate the production bore.

Add new NOTE 1

NOTE 1 SDSS components may be proposed for use for sensor flanges and housings, flow loops and small-bore injection isolation valves where project specific fluid properties allow.

Add to subsection

The annulus and other pressure-containing components within the annulus flow path shall be at least material class EE.

Add new NOTE 2

NOTE 2 Penetrations into the tree and tubing hanger between the UCP and LCP and associated isolation valve may be material class EE.

Add to subsection

All metal-to-metal sealing surfaces on pressure-containing or pressure-controlling components within the annulus flow path shall be manufactured from, or inlaid with, a corrosion-resistant alloy.

Add to subsection

Chemical injection porting through tree and tubing hanger bodies shall be at least material class EE from the production or annulus bore intersection out to the isolation.

Add to subsection

Seal preps, couplers and isolation valve trim shall be at least material class EE for downhole chemical injection ports.

Add to subsection

Fittings and tubing shall be at least material class FF for downhole chemical injection ports.

Add to subsection

Provision shall be made for one downhole chemical injection port to be full HH trim through both the tree and tubing hanger including seal preps, couplers, fittings and isolation valve.

Add to subsection

Tree and suspension equipment re-entry sealing surfaces shall be of corrosion resistant material.

5.1.3 Design Methods and Criteria

Add to subsection

Values and methods, including supporting validations, for make-up tension (or torque) for closure bolting and critical bolting shall be available at the manufacturer's site for review upon request.

Add to subsection

If the values in Annex F are used for bolt torque make-up, all requirements in Annex F shall be fulfilled.

Add to subsection

For pressure-containing bolting, a validated process shall be used to provide indication of bolt make-up after final assembly of that bolted connection and again after the test with the highest pressure that the assembled bolted joint is subjected to during testing.

Add new subsection

5.1.3.8 Seal Requirements

For vertical tree systems, pressure-containing seals on permanent equipment shall be metal-to-metal except for tree cap, tubing head spool isolation sleeve and tubing hanger external seals where non-metallic seals may be used.

For horizontal tree systems, pressure-containing seals on permanent equipment shall be metal-to-metal except for XT isolation sleeve and non-production-wetted TH gallery seals where non-metallic seals may be used.

Valve and choke stem primary seals shall be metal-to-metal or thermoplastic.

Valve and choke stem secondary seals shall be metal-to-metal, thermoplastic or encapsulated elastomeric seal.

Metal-to-metal seals shall have a secondary seal element, except for the following:

— wellhead gaskets;

— flowline connection gaskets;

— valve gate to seat seals;

— static seals that are assembled and tested at the factory (e.g. bonnet gasket, BX gasket).

NOTE Secondary seal elements may be non-metallic (e.g. production seal stabs, tubing hanger OD seals) and combined into one sealing assembly.

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

Non-metallic seals made up subsea shall be testable or have a non-metallic backup seal element, except for the following:

— isolation sleeve seal to wellhead;

— tree cap seal;

— tubing hanger gallery seal that is downstream of a primary metal seal;

— when hydraulic lock or thermal expansion can cause a trapped pressure to exceed seal design rating.

5.1.4 Miscellaneous Design Information

5.1.4.6 Cathodic Protection

Add to subsection

CP design shall take into account all connected items that do not have an independent CP system.

Add to subsection

A CP system shall be provided on the tree frame, tubing head frame and completion guidebase.

Add to subsection

The CP system of each assembly shall provide protection to one half of flying leads and well jumpers connected to that assembly.

Add to subsection

The well drain current shall be allocated to the lowermost assembly in the stack up.

5.1.4.8.1

Designs shall achieve electrical continuity among assembled components of subsea equipment that are protected by the CP system.

5.1.4.8.2

Unless they are equipped with alternative measures such as high-performance coatings, components constructed of metals not compatible with the applied CP levels shall be electrically isolated from the CP system.

5.1.4.8.3

The anti-fouling properties of copper and copper-based alloys shall be considered ineffective where they have continuity with the CP system.

5.1.4.8.4

Copper filters on sea chests shall be isolated from the CP system.

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

5.1.4.8.5

Non-welded connections within component assemblies shall be included in the scope of testing and remediation in accordance with 5.4.8.

5.1.7 Validation

5.1.7.1 Introduction

Add to subsection

Product designs that have undergone a substantive change as defined in 3.1.60 shall be treated as new product designs requiring validation, with the exception that any portion of the validation that is not affected by the substantive change does not need to be repeated.

Add to subsection

Validation for new product designs shall conform to 5.1.7 as amended by Annex Q.

5.2 Materials

5.2.1 General

5.2.1.1 Manufacturing Requirements

Add to subsection

Carbon and low alloy steel forgings shall comply with Annex C.

5.2.1.2 Heat Treatment and Qualification Test Coupons

Replace subsection with

For materials manufactured in accordance with DNV-RP-0034 as per Annex C, heat treatment practices and QTCs shall conform to DNV-RP-0034.

Heat treatment practices and QTCs for materials other than those manufactured in accordance with DNV-RP-0034 as per Annex C shall conform to API 6A.

Material certification shall be as per EN 10204 level 3.1.

6 General Design Requirements for Subsea Tree Systems

6.1 General

6.1.1 Introduction

Add to subsection

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 "when lifted in the as-run condition" with

when lifted in the as-run condition while made up to the running tool

6.2 Tubing Head and Tree Valving

6.2.1 Master Valves, Vertical Tree

Add to subsection

The production (injection) master valve shall be integral to the tree body.

Add to subsection

The production (injection) master valve shall be actuated fail-closed.

Add to subsection

The annulus master valve shall be integral to the tree body.

Add to subsection

The annulus master valve shall be actuated fail-closed.

6.2.2 Master Valves, Horizontal Tree

Add to subsection

The production (injection) master valve shall be integral to the tree body.

Add to subsection

The production (injection) master valve shall be actuated fail-closed.

Add to subsection

The annulus master valve shall be integral to the tree body.

Add to subsection

The annulus master valve shall be actuated fail-closed.

6.2.3 Wing Valves, Vertical Tree

Add to subsection

The production (injection) wing valve shall be integral to the production wing block or tree body.

Add to subsection

The production (injection) wing valve shall be actuated fail-closed.

Add to subsection

The annulus wing valve shall be integral to the annulus block or the tree body.

Add to subsection

The annulus wing valve shall be actuated fail-closed.

6.2.4 Wing Valves, Horizontal Tree

Add to subsection

For horizontal subsea trees, the production (injection) wing valve shall be integral to the production wing block or tree body.

Add to subsection

The production (injection) wing valve shall be actuated fail-closed.

Add to subsection

The annulus wing valve shall be integral to the annulus block or the tree body.

Add to subsection

The annulus wing valve shall be actuated fail-closed.

6.2.5 Crossover Valves

Add to subsection

An actuated fail-closed $2^1/_{16}$ in. (52 mm) crossover valve shall be provided.

6.2.8 Production (Injection) and Annulus Flow Paths

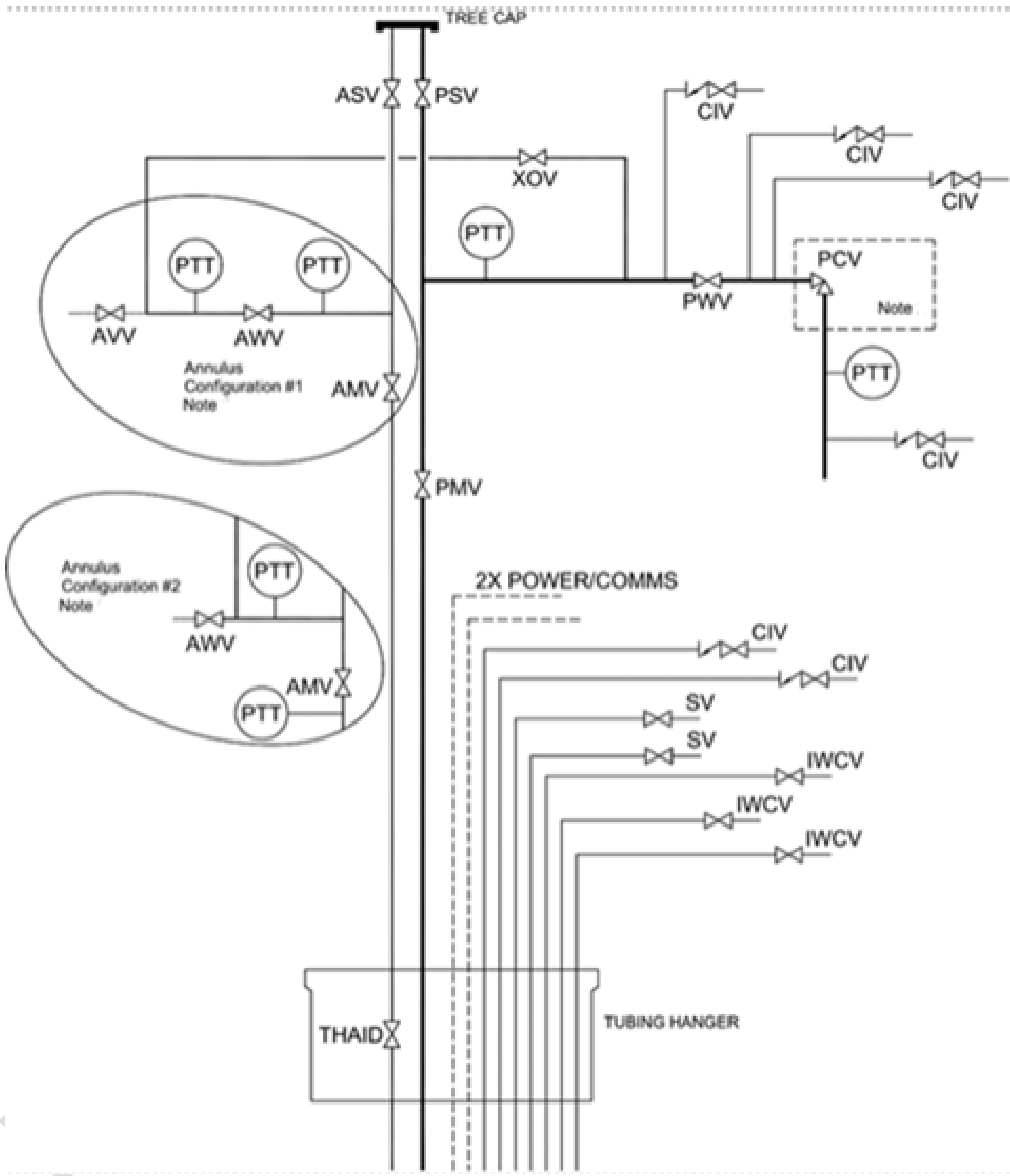
Add after third paragraph

Tree and tubing head annulus flow path and main annulus valves (i.e. AMV, ASV, AWV, AAV), excluding the THAID, shall be nominal $2^1/_{16}$ in. (52 mm).

Add after third paragraph

Connections between the tree block, including any horizontal penetrator assembly, and the isolation valve for lines entering or in communication with the well bore, including the annulus, shall be fully welded or flanged.

Replace Figure 1 with



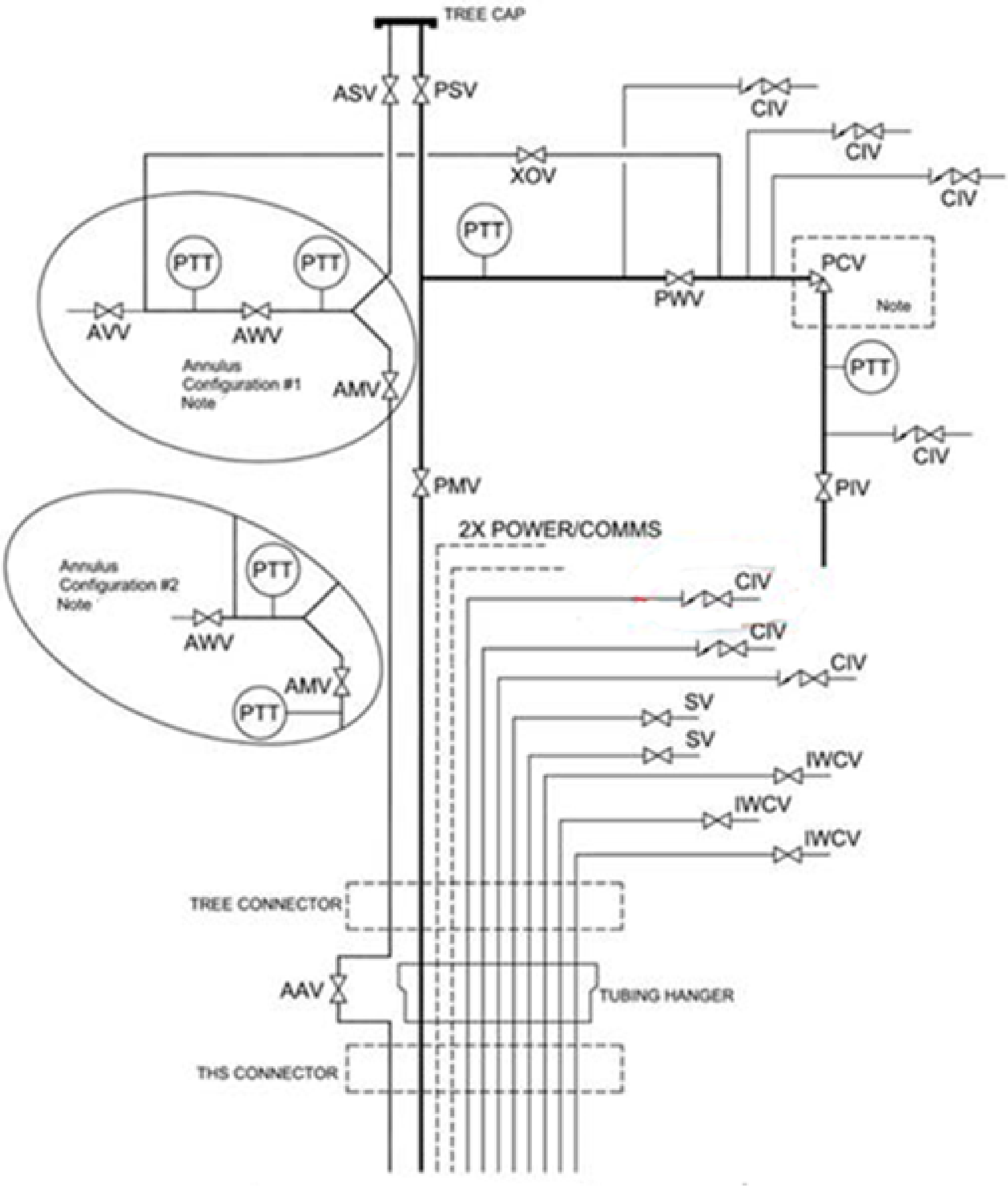
NOTE This figure shows the crossover production-bore intersection option of inboard of the PWV and an example of sensor and injection location options. In this figure, the downhole function number may be reduced (refer to 6.7.4) and alternative chemical injection isolation valve arrangements may be specified (refer to 6.2.9). The crossover access into the annulus bore can be between the AWV and AVV (Configuration #1) or inboard of the AWV (Configuration #2). Refer to the data sheet and project P&ID for requested crossover bore intersection locations and type and number of functions (sensors, injection points, etc.).

Replace Figure 1 title with

Figure 1—VXT Dual-bore on a Subsea Wellhead

Replace Figure 2 with Figure 2 a) and Figure 2 b)

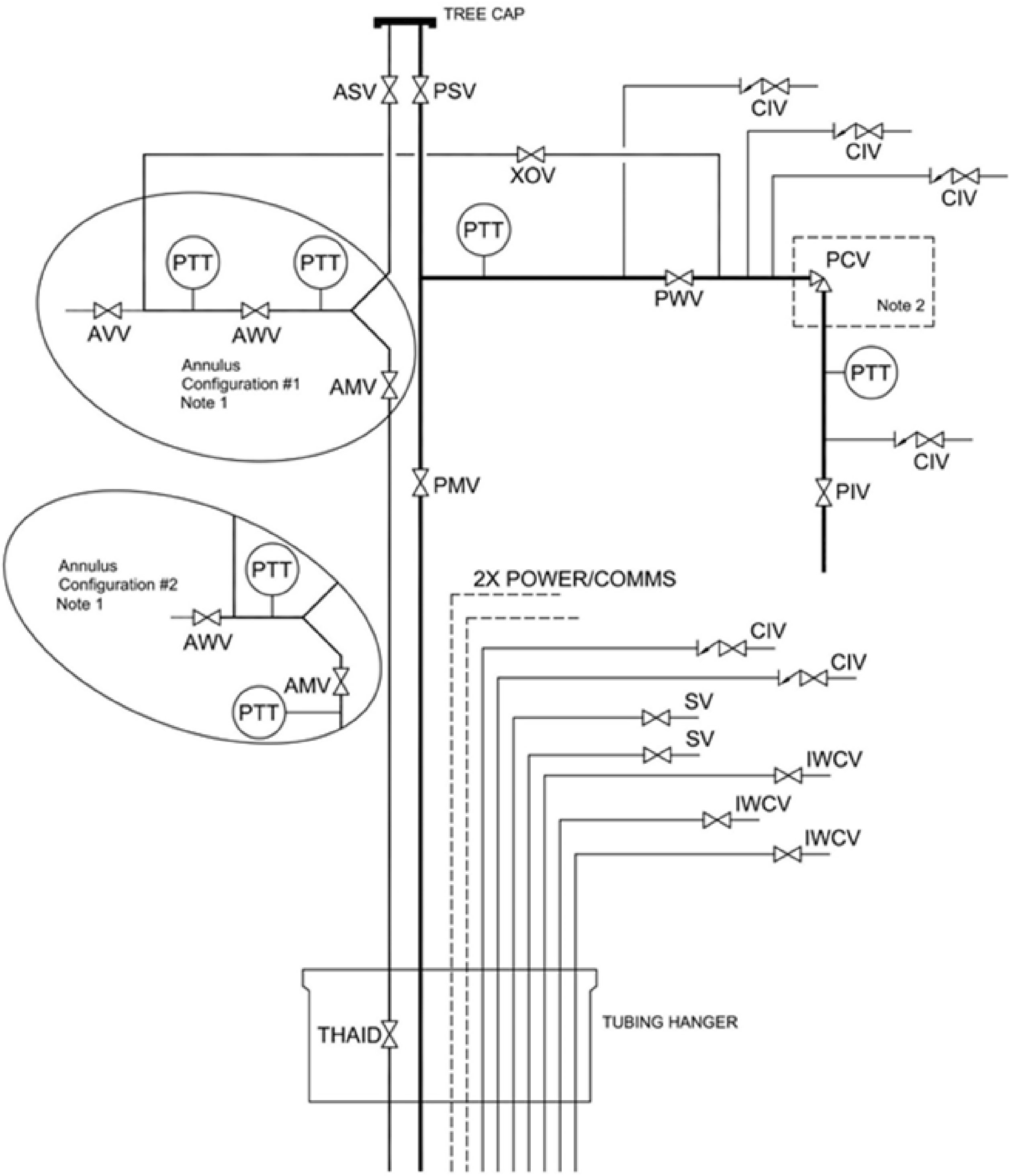
Add new Figure 2 a)



NOTE This figure shows an example of sensor and injection location options and the crossover production-bore intersection option of between PWV and PCV. The alternative downhole function number (refer to 6.7.4) and chemical injection isolations (refer to 6.2.9) may be specified for Figure 2 a). The crossover access into the annulus bore can be between the AWV and AVV (Configuration #1) or inboard of the AWV (Configuration #2). Refer to the data sheet and project P&ID for requested crossover bore intersection locations and type and number of functions (sensors, injection points, etc.).

a) VXT Monobore on a Tubing Head

Add new Figure 2 b)



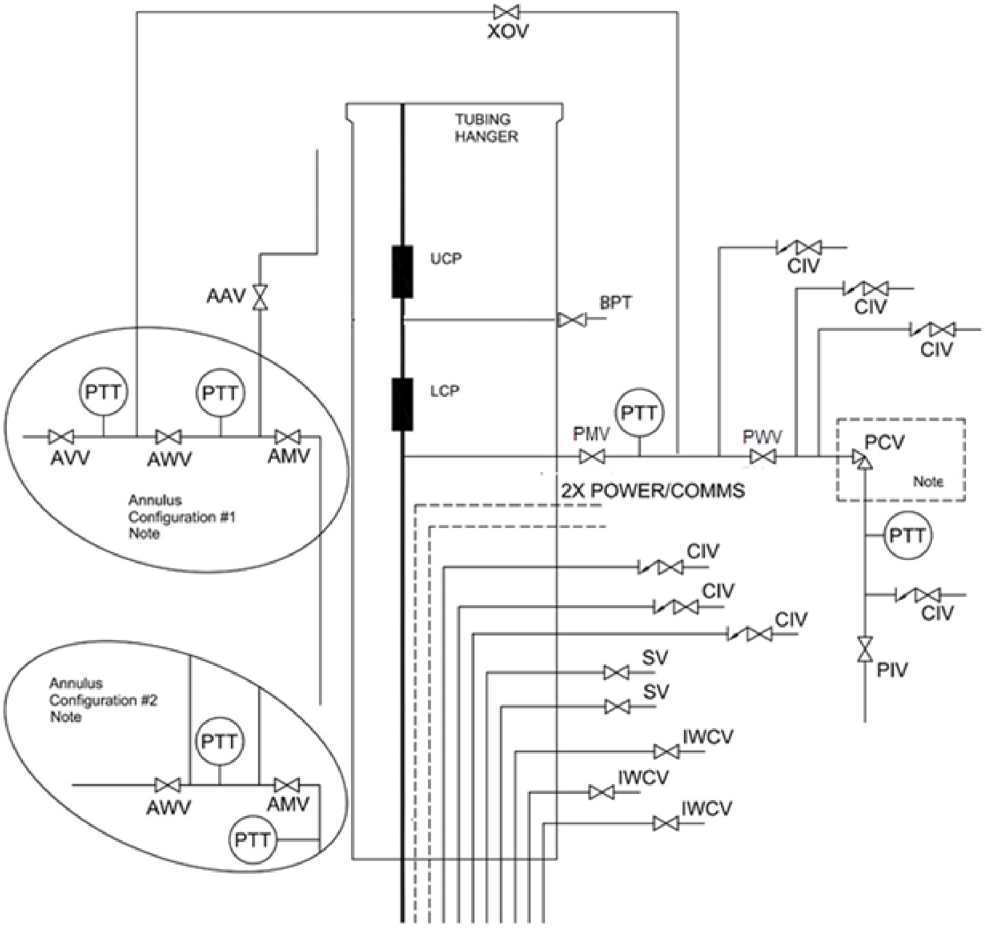
NOTE This figure shows an example of sensor and injection location options and the crossover production-bore intersection option of between PWV and PCV. The alternative chemical injection isolation valve arrangements may be specified (refer to 6.2.9). The crossover access into the annulus bore can be between the AWV and AVV (Configuration #1) or inboard of the AWV (Configuration #2). Refer to the data sheet and project P&ID for requested crossover bore intersection locations and type and number of functions (sensors, injection points, etc.).

b) VXT Monobore on a Subsea Wellhead

Replace Figure 2 title with

Figure 2—Vertical Monobore Trees

Replace Figure 3 with



NOTE This figure shows an example of sensor and injection location options and the crossover production-bore intersection option of inboard of PWV. The alternative chemical injection isolation valve arrangements may be specified (refer to 6.2.9). The crossover access into the annulus bore can be between the AWV and AVV (Configuration #1) or inboard of the AWV (Configuration #2). Refer to the data sheet and project P&ID for requested crossover bore intersection locations and type and number of functions (sensors, injection points, etc.).

Replace Figure 3 title with

Figure 3—Horizontal Tree on a Subsea Wellhead

Figure 4—Examples of Bore Penetrations

Delete Figure 4

Add new subsection

6.2.8.2 Additional Annulus Flow Path Pressure Closures

6.2.8.2.1

If the AVV is not integral or bolted to the annulus wing block, the flow path between the block and the AVV shall have fully welded or flanged connections.

6.2.8.2.2

The AVV and its flow path shall be protected from impact and dropped objects in accordance with API 17A.

NOTE Service line tie-in requirements are not covered by this specification as these are project specific defined items.

6.2.8.2.3

There shall be at least two fail-closed valves between the PTT monitoring the A-annulus and the production bore flow path as shown in annulus Configuration #1 and Configuration #2 in Figure 1, Figure 2 and Figure 3.

6.2.9 Production and Annulus Bore Penetrations

Add to subsection

Through-block test ports located between crown plugs on HXT or above swab valves on the VXT shall have dual means of isolation of retained fluids for all intervention configurations.

Add new NOTE 2

NOTE 2 Isolations may be by means of any combination of valve, sealing bore-stab, isolation sleeve, etc.

Add to subsection

Unused features (sensor ports, downhole lines, etc.) shall be blanked off with metal-sealing plugs or flanges.

Add new section

6.2.9.1 Penetration Isolation Configurations

6.2.9.1.1

Isolation and check valves for production and annulus bore chemical injection port penetrations shall be configured in accordance with one of the following three options:

— single remotely actuated gate valve plus a check valve located between the gate valve and the bore;

— two remotely actuated gate valves;

— single remotely actuated gate valve used on a penetration outboard of the PMV or AMV.

NOTE 1 These options replace Figure 4 a) and Figure 4 b).

NOTE 2 Different options may be used on different ports on the same tree as needed for valve, operator, and interface packaging and access.

6.2.9.1.2

When there is a single remotely actuated gate valve plus a check valve located between the gate valve and the bore, the gate valve shall satisfy the requirement of 6.2.9.2.

6.2.9.1.3

When there is a single remotely actuated gate valve plus a check valve located between the gate valve and the bore, the check valve shall be block mounted.

6.2.9.1.4

When there are two remotely actuated gate valves, one gate valve shall be integral or bolted to the block, except on HXT horizontal penetrator system circuits that satisfy the requirement of 6.2.9.2.

NOTE 3 One valve may be panel mounted.

6.2.9.1.5

When there is a single remotely actuated gate valve used on a penetration outboard of the PMV or AMV, the gate valve shall satisfy the requirement of 6.2.9.2.

6.2.9.2 Penetrations Inboard Isolation Requirements

The inboard gate valve on production and annulus penetration shall be either of the following:

— integral or block mounted;

— mounted to a block elbow that is bolted to the block when consideration for extended dead-leg and seawater cooling effect does not preclude the use of a block elbow; or

— connected to the block using fully welded or flanged connections on a circuit that is protected from impact and dropped objects in accordance with API 17A.

6.2.10 SCSSV Control Line Penetrations

Figure 5—Examples of Tree Valving for Downhole Chemical Injection and SCSSV

Delete Figure 5

6.2.11 Downhole Chemical Injection Line Penetrations

Replace third paragraph with

If a check valve is used as one of the two required isolation barriers, the check valve shall be located inboard of the other isolation barrier.

If a check valve is used as one of the two required isolation barriers, the other isolation barrier shall be a fail-closed gate valve.

6.3 Thermally Induced Pressure Changes

Add to subsection

Areas requiring analysis shall include the following:

— isolated chambers used for testing secondary barriers (e.g. gasket test chambers);

— cavity between the crown plugs in the HXT and the area above the swab valves but below the tree cap in a VXT;

— other areas that create or may create an isolated volume (e.g. areas between dual seals, and areas between valves on the crossover loop that remain closed during start-up or shutdown); and

— unused, plugged off or isolated functions (e.g. unused downhole penetrations).

6.4 Testing of Subsea Tree Assemblies

6.4.2 Factory Acceptance Testing

Add to subsection

Valves exposed to retained fluids, including small bore injection isolation valves (including check valves) and chokes, shall be PSL 3G tested in accordance with 5.4.6, except that there is no requirement for the following:

— gas back seat testing;

— gas testing of valves in hydraulic circuits;

— gas testing of gallery areas that are not exposed to retained fluids in production and intervention modes and configurations;

— repeat of gas testing already performed at sub-assembly level;

— gas testing of the tubing hanger interface with the XT at the XT assembly FAT when necessary gas testing of internal features has been completed and verified at other stages of FAT;

— gas testing of the tubing hanger interface with the tubing head at the tubing head assembly FAT when necessary gas testing of internal features has been completed at other stages of FAT.

Add to subsection

Full production and annulus flow paths of production and gas injection tree final tree assemblies shall be submerged gas tested.

Add new NOTE 3

NOTE 3 Any subcomponents not previously gas tested may be included in this test to satisfy their gas test requirement.

Add to subsection

The hold period shall be 1 hour after stabilization from submersion for the submerged gas test of the full production and annulus flow paths of production and gas injection tree final tree assemblies.

Add to subsection

Acceptance criteria for the submerged gas test shall be no bubbles during the hold period.

Add new section

6.7 Tree Configurations

6.7.1 Pressure and Temperature Sensors

6.7.1.1

XTs shall include provision for a single housing between the PMV and PWV.

6.7.1.2

XTs shall include provision for a single housing in the production bore downstream of the choke.

6.7.1.3

XTs shall include provision for a single housing between the AMV and AWV.

6.7.1.4

XTs shall include provision for a single housing outboard of the AWV (Configuration #1) or inboard of the AMV (Configuration #2).

6.7.1.5

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

6.7.1.6

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

6.7.2 Blockage Avoidance

6.7.2.1

The tree configuration shall orient injection ports and gauge bores to be self-draining.

NOTE The risk of blockage and hydrates increases with the length of dead leg bores that intersect the production flow path.

6.7.2.2

To be considered 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.

6.7.2.3

Where the first isolation on a chemical injection line is not block-mounted, the connection line between the block and the isolation shall be insulated unless thermal analysis confirms that the line remains above hydrate formation temperature during normal flowing conditions.

6.7.3 Chemical Injection / Control Line Provision

6.7.3.1 Downhole Control and Chemical Injection

6.7.3.1.1

All tree types, except monobore VXT, shall have provision for nine total downhole lines.

6.7.3.1.2

Monobore VXTs on tubing head shall have provision for ten total downhole lines.

NOTE Grouping downhole chemical injection line ports together at the bottom of the tubing hanger avoids the need to cross downhole lines over each other along the production tubing downhole.

6.7.3.1.3

Valves and porting for hydraulic or chemical lines shall be sized equivalent to at least $^3/_8$ in. (10 mm) OD tubing.

6.7.3.1.4

For all tree types, up to two of the downhole lines shall be configurable as electrical or fiber optic lines.

6.7.3.1.5

Features not required, i.e. as per data sheet specified configuration or P&IDs, shall be blanked or not machined.

6.7.3.2 Chemical Injection at Tree

6.7.3.2.1

Tubing on tree chemical injection lines shall be at least ½ in. (12.7 mm) OD tubing, except for the two lines specified in 6.7.3.2.3 and 6.7.3.2.8 as higher flow rate.

6.7.3.2.2

The bores of valves and porting on all other tree chemical injection lines shall be at least equivalent to ½ in. (12.7 mm) OD tubing, except for the two lines specified in 6.7.3.2.3 and 6.7.3.2.8 as higher flow rate.

6.7.3.2.3

There shall be one high flow rate chemical injection line between the PMV and the PWV.

6.7.3.2.4

The tubing on the high flow rate chemical line between the PMV and the PWV shall be at least 1 in. (25 mm) OD tubing.

6.7.3.2.5

The bores of valves and porting on the high flow rate chemical injection line between the PMV and the PWV shall be at minimum ¾ in. (19 mm).

6.7.3.2.6

There shall one chemical injection line outboard of the PCV.

6.7.3.2.7

There shall be two chemical injection lines between the PWV and the PCV.

6.7.3.2.8

One of the chemical injection lines inboard or outboard of the PCV shall be designed as high flow rate line as specified.

6.7.3.2.9

The tubing on the high flow rate chemical line the chemical injection line inboard or outboard of the PCV shall be at least 1 in. (25 mm)OD tubing.

6.7.3.2.10

The bores of valves and porting on the high flow rate chemical injection line inboard or outboard of the PCV shall be at minimum ¾ in. (19 mm).

6.7.4 Drill-Through Requirement

6.7.4.1

If drill-through is specified, the HXT and tubing head shall be sized for through bore drilling of bottom hole sections using a 12¼ in. (315 mm) bit.

6.7.4.2

If drill-through is specified, the HXT and tubing head internals (e.g. seal areas and landing/locking profiles for the TH) shall be protected with a bore protector during drilling and downhole operations.

6.7.5 Horizontal Tree Systems

6.7.5.1

At least one access port to the cavity between the crown plugs shall be provided.

6.7.5.2

Each test and vent lines shall be fitted with an ROV operated isolation gate valve.

6.7.5.3

Tubing for test and vent lines shall be $^3/_8$ in. (10 mm) OD or larger.

6.7.5.4

Porting and isolation valves for test and vent lines shall be $^1/_4$ in. (6.35 mm) ID minimum.

6.7.5.5

Access to the TH gallery seal shall be provided via the test port to test the sealing ability of penetrators and upper and lower gallery seals.

NOTE There is no requirement for online monitoring of the pressure in the TH gallery port or the port between the crown plugs.

6.7.6 Insulation Provision

The tree system geometry shall accommodate thermal insulation.

7 Specific Requirements—Subsea Tree-related Equipment and Subassemblies

7.8 Tree and Tubing Head Connectors

7.8.1 General

7.8.1.1 Tree and Tubing Head Connectors

Add to subsection

The tree and tubing head connector gasket sealing profile shall be integral to the main block.

Add to subsection

The tree and tubing head connector design shall allow to replacement of the connector gasket without retrieving the connector to the surface, except for tree or tubing head configurations where the isolation sleeve seals directly to the wellhead ID or could interfere with the subsea gasket changeout functionality.

Add to subsection

The test port shall be fitted with an ROV operated valve to provide the connector gasket sealing testing capability.

Add to subsection

The valve shall have a pressure rating corresponding to that of the tree system.

Add new subsection

7.8.4 Isolation Sleeve for HXT and Tubing Head

7.8.4.1

The isolation sleeve shall provide pressure sealing above the wellhead gasket, i.e. in the spool/body, and below the wellhead gasket, i.e. in the wellhead system.

7.8.4.2

The isolation sleeve shall be capable of withstanding the HXT and tubing head rated working pressure internally and externally.

7.10 Valves, Valve Blocks, and Actuators/Operators

7.10.2 Design

7.10.2.1 Valves and Valve Blocks

7.10.2.1.1 General

Add to subsection

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

Add to subsection

Valves on water injection trees shall be PSL 3 or PSL 3G.

Add to subsection

Tree gate valves in production and crossover bores, excluding CIVs, shall be rated for class II sandy service as defined by API 6AV1, except for valves on water injection trees.

Add to subsection

Gate valves shall be designed to seal bi-directionally.

Add to subsection

Actuated gate valves sized $2^{1}/_{16}$ in. (52 mm) nominal bore and larger shall accommodate ROV override.

Add to subsection

Stem seals shall function under all combinations of the rated internal and external pressures, including pressure changes during deployment.

7.11 Re-entry Interface

7.11.1 General

Add to subsection

The upper hub or mandrel shall be integral to the tree body.

7.11.2 Design

7.11.2.2 Re-entry Interface Upper Connection/Profile

Add to subsection

For trees and tubing heads, the upper re-entry interface shall be a mandrel profile with an $18^{3}/_{4}$ in. (476 mm) nominal ID and 27 in. (685.8 mm) nominal OD.

Add to subsection

Re-entry mandrels shall be designed to accept a contingency gasket that seals in a different location than the primary gasket.

Add to subsection

On HXTs and tubing heads, the mandrel shall facilitate a funnel down BOP connector with a swallow of 41 in. (1040 mm) below the mandrel top and diameter of 68 in. (1730 mm).

7.12 Subsea Tree Cap

7.12.1 General

Add "(Debris Cap)" to subsection 7.12.1.2 title

7.12.1.2 Non-pressure-containing Tree Cap (Debris Cap)

Add after first paragraph

The debris cap shall cover and protect the tree and tubing head re-entry mandrel.

The debris cap shall accommodate the use of a subsea corrosion inhibitor.

7.12.1.3 Pressure-containing Tree Cap

Add to subsection

Pressure-containing tree caps shall have a means, whether visual or mechanical, to verify that the cap is locked.

Where overpull is used to verify that cap is locked, overpull load allowable range shall be provided.

Retrieval load capacity and its range shall be provided by the supplier.

For VXT tree systems, the tree system shall be designed to enable circulation through the vent lines to ensure that there is no trapped pressure before removal of the pressure-containing tree cap.

NOTE This may be achieved in the tree cap or through porting into the cavities below the tree cap.

7.14 Tree and Tubing Head Guide Frames

7.14.2 Design

7.14.2.1 Guidance and Orientation

Add to subsection

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

7.14.2.3 Design Load/Conditions

Add to subsection

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

Add to subsection

Shipping and handling protection shall be provided.

7.16 Tree, Tubing Head, and Completion Guidebase Piping

7.16.2 Design

7.16.2.3 Tree Piping Flowloops

Add to subsection

Crossover piping shall be $1^1/_2$ in. (38.1 mm) ID minimum.

When crossover porting is drilled in the forged body, the porting shall be $1^1/_2$ in. (38.1 mm) ID minimum.

7.19 Tree-mounted Hydraulic/Electric/Optical Control Interfaces

7.19.2 Design

7.19.2.2 Size and Pressure

Replace first sentence with

All pipe/tubing/hose shall be $^3/_8$ in. (10 mm) OD or larger.

7.19.2.6 Small-bore Tubing and Connections

Add new list subsection to first paragraph

— Mechanical connections shall provide leak tight performance for the life of the field.

Add new list subsection to first paragraph

— Tubing connections shall be one or more of the following:

a) fully welded or flanged;

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

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

d) twin ferrule compression fittings;

e) other tubing connection that has been validated for relevant load cases including vibration from transportation, shock loads, pressure fluctuations and production loadings.

Add new list subsection to first paragraph

— Connections shall be fully welded or flanged between the tree block (including any horizontal penetrator assembly) and the isolation valve for lines entering or in communication with the well bore, including the annulus.

Add new list subsection to first paragraph

— Rotational back-off preventative measures such as coned and threaded tube anti-vibration collars shall be used at all mechanical fittings.

Add new list subsection to first paragraph

— Tubing runs shall be secured to prevent rotation of the tube and unthreading of the fitting.

Add new list subsection to first paragraph

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

Add new list subsection to first paragraph

— Transitions between tubing of differing wall thicknesses shall use tapered transition joints.

Add new list subsection to first paragraph

— Socket weld connections shall not be used.

Add new list subsection to first paragraph

— Tubing runs shall be supported with clamps at intervals as defined in Table 36.

Add new list subsection to first paragraph

— Clamps shall conform to DIN 3015-1.

Add new list subsection to first paragraph

— Tubing runs shall be a single piece from starting point to ending point wherever possible.

Delete second paragraph (For a line that penetrates the wellbore...) including list items

Delete third paragraph (For a line that does not penetrate the wellbore…)

Add new Table 36

Table 36—Maximum Allowable Distance Between Tubing Clamps

Tube OD		Maximum Allowable Distance	
in.	(mm)	in.	(mm)
$^3/_8$ to $^1/_2$	(10 to 12)	24	(600)
$^5/_8$ to $^7/_8$	(14 to 22)	40	(1000)
1	(25)	60	(1500)

7.20 Subsea Chokes and Actuators/Operators

7.20.1 General

Add to subsection

Chokes on production trees and on gas injection trees shall be designed, manufactured and tested for API 6A/API 17D PSL 3G service.

Add to subsection

Chokes for only water injection service shall be PSL3 or PSL3G.

Add to subsection

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

Add to subsection

There shall be two independent methods of determining the choke position as described in 7.20.1 a) and b).

a) Chokes shall be provided with a primary means of position indication via feedback through the production control system.

b) Chokes shall be provided with a secondary means of position indication via an external position indicator.

NOTE Secondary external position indication may be by means of tooling or local indicator.

9 Specific Requirements—Subsea Tubing Hanger System

9.1 Design

9.1.1 General

Add to subsection

Horizontal tree type tubing hangers shall be of dual crown plug design.

Add to subsection

For horizontal tree type tubing hangers, the orientation feature shall allow the tubing hanger to be installed from any heading.

9.1.2 Design Load/Conditions

Add to subsection

The TH shall resist rotational torque of 35,000 ft-lbs (47,500 N m) to accommodate built-up torque when setting the hanger, especially in deviated wells.

Add to subsection

The rated rotational load capacity shall be provided by the supplier.

9.1.9 Stab Design for SCSSV, Other Hydraulic, and Chemical Injection Control Lines

Add to subsection

For a VXT, where a spring-loaded relief valve is utilized on the SCSSV line, the relief valve shall not maintain a pressure within the SCSSV circuit of more than 100 psi (0.69 Mpa).

Add to subsection

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

Add new subsection

9.1.11 Tubing Hanger Annulus Isolation Device

The THAID shall provide isolation of the annulus flow path through the tubing hanger.

The THAID shall withstand a differential of full RWP of the tubing hanger in either direction when in the closed position.

The THAID shall be operable closed to open with differential pressure of RWP from below, without compromising the sealing capability.

The THAID shall be operable by an ROV or a 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 the BOP installed on the wellhead and with the tree installed on the wellhead.

The THAID shall be fail-as-is or fail-close.

The THAID shall not result in unintentional operation due to the application of pressure from above or below.

The THAID shall have a secondary actuation method for closing the THAID.

The THAID shall 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 1 in.^{2} (645.16 mm^2), with the THAID in the fully open position.

Annex J
(informative)

Validation of Valves and Actuators/Operators

J.2 General Requirements

Add before first paragraph

The valve and hydraulic actuator assembly performance limits shall be validated in accordance with the criteria given in 7.10.4.1.2.

Add to third paragraph

Hyperbaric cycles shall be in accordance with 7.10.4.1.3.

NOTE This satisfies the 200 pressure/load cycles and 200 of the 600 endurance cycles detailed in Table 5.

Add to fifth paragraph

Pressure testing shall be performed in the expected direction of flow.

The direction of flow shall be consistent throughout all testing, with the exception of the final bi-directional low-pressure seat test for gate valves as specified in API 6A, F.2.2.2.15 and of the FAT gas seat test as specified in API 17D, 5.4.6.4.

Add to sixth paragraph

Each type of cycle (endurance, hyperbaric, PR2) shall be fully completed prior to progressing to the next one.

Add to subsection

Acceptance criteria for all gas stages of validation shall be in accordance with API 17D, 5.4.6.4 for PSL 3G equipment and pressure-containing seals, and API 6A, F.1.6.2 for pressure-controlling seals.

J.5 Validation of Valves with Manual Operator (ROV/Diver Operated)

J.5.4 Hyperbaric Pressure Testing

Add to second paragraph

Hyperbaric cycles in accordance with Annex N shall be conducted at a temperature not to exceed 120 °F (49 °C).

Annex Q
(informative)

Validation Testing

Q.1 Introduction

Q.1.1

This annex provides guidance with respect to validation testing.

Q.1.2

This annex addresses clarifications and informative additions to API 17D validation testing and should be read concurrently with 5.1.7.

Q.1.3

The intent of this annex is to provide a standard interpretation of API 17D validation testing requirements.

Q.1.4

The stated requirements are value adding practice for the validation of new products or re-validation of existing products due to a substantive change.

Q.1.5

The intent of this annex is also to define a standard practice for current and future equipment validation.

Q.1.6

It is not intended to imply that equipment that has been previously validated to API 17D needs to have additional validation or re-validation.

Q.2 General

Q.2.1

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.

Q.2.2

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.

Q.2.3

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.

Q.3 Temperature Cycling Tests

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

Q.4 Life cycle / Endurance Testing

Q.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 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.

Q.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 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 described in a) through e).

NOTE 1 This satisfies the 200 pressure/load cycle tests and 3 temperature cycle tests of Table 3.

a) Before performing all the steps described in b) through d), the seal should undergo FAT including a gas test as follows:

   — at ambient temperature;

   — at rated working pressure;

   — with a hold period of 15 minutes.

b) Pressure and temperature cycles should be performed in accordance with API 6A, F.1.11.

c) 200 pressure cycles at ambient temperature should be performed in accordance with 5.1.7.4.

   NOTE 3 Steps b) and c) can be performed in either order.

d) After steps b) and c) have been completed, a gas test should be performed as follows:

   — at ambient temperature;

   — at rated working pressure;

   — with a hold period of 15 minutes.

e) Seals should be validated with hyperbaric testing in accordance with Annex N 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 5.4.6.4 for PSL 3G equipment.

Acceptance criteria for minimum/maximum temperature tests should be in accordance with API 6A, F.1.6.2.3.

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 is 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.

Q.4.3 Subsea valves

Q.4.3.1 General

Q.4.3.1.1

Validation of subsea valves should be in accordance with Annex J.

Q.4.3.1.2

Valve validation testing should be in accordance with Table Q.1.

Q.4.3.1.3

After performing all testing described in Q.4.3.1.2, the valve should undergo a gas body and gas seat test in accordance with 5.4.6.3 and 5.4.6.4, with acceptance criteria as stated in Q.4.3.1.4, Q.4.3.1.5 and Q.4.3.1.6.

Q.4.3.1.4

Acceptance criteria for all gas stages of validation should be in accordance with 5.4.6.4 for PSL 3G equipment and for pressure-containing seals, and API 6A, F.1.6.2 for pressure-controlling seals.

Q.4.3.1.5

For hyperbaric testing in accordance with Annex N, there is no requirement to maintain the test medium at 40 °F ± 10 °F (4 °C ± 5 °C) throughout the test.

Q.4.3.1.6

The testing described in Q.4.3 satisfies the validation requirements for valve seals including those of Q.4.2.

Q.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 Q.4.3.1 should be the same valve used for API 6AV1 validation.

Q.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.

Q.4.3.4 Needle Valves

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

Q.4.4 Subsea Valve Actuators

Q.4.4.1 General

Q.4.4.1.1

The general requirements in this subclause should apply to valve actuators, both hydraulically and manually operated.

NOTE 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.

Q.4.4.1.2

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.

Q.4.4.1.3

Valve actuator validation testing should meet API 17D requirements as described in a) through c) (see Table Q.1).

a) PR2 sequence should be performed in accordance with API 6A, F.2.3 for PR2F actuators.

   NOTE 1 This satisfies 200 of the 600 endurance cycles and the 3 temperature cycles required by Table 5.

b) 200 hyperbaric cycles should be performed in accordance with Annex N.

   NOTE 2 This satisfies the 200 pressure/load cycles and 200 of the 600 endurance cycles required by Table 5.

c) 200 endurance cycles should be performed in accordance with API 6A, F.2.3.2.2 except that the number of cycles should be 200.

Steps a) through c) should complete the 600 endurance cycles required by Table 5.

Q.4.4.1.5

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

Q.4.4.2 Hydraulic Valve Actuators

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

Before the testing described in Q.4.4.1, the actuator should undergo FAT including hydrotests at 20 % and 100 % of the RWP of the actuator, as described in 7.10.4.2.3.3.

Q.4.4.3 Valve Actuators with ROV Linear Override

Q.4.4.3.1

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 Q.4.4.1.

Q.4.4.3.2

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 the RWP pressure differential across the gate;

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

Q.4.4.3.3

Valve signatures may be used in lieu of direct force measurement where they provide equivalent data to Q.4.4.3.2 a), b) and c).

Q.4.4.3.4

Either during validation testing or as a separate test, the maximum operating force (i.e. 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.

Q.4.4.4 Valve Actuators with ROV Rotary Override and Manual Valve Actuators

Q.4.4.4.1

Torque required, number of turns and direction of rotation to operate should be measured and recorded before and after completion of testing in Q.4.4.1.

Q.4.4.4.2

The following measurements should be 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 the RWP differential across the gate;

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

d) number of turns and direction to operate.

Q.4.4.4.3

In Q.4.4.4.2 d), performance of the open/close indicator should be validated against the number of turns.

Q.4.4.4.4

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.

Q.4.5 Tubing Hanger Annulus Isolation Device

Q.4.5.1

The annulus isolation device validation testing should meet the requirements described in Q.4.5.2 and Q.4.5.3.

Q.4.5.2

Individual seals should be validated by completion of the pressure and temperature sequence cycling described in API 6A, F.1.11.

NOTE 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.

Q.4.5.3

The annulus isolation device assembly should be validated by completion of the test sequence described in a) through m), based on API 6A, Annex F PR2 requirements.

NOTE 1 Seals may be changed out prior to the start of this test sequence.

a) Before performing all the steps described in b) through m), the device should undergo FAT including a gas body and gas seat test in accordance with 5.4.6.3 and 5.4.6.4.

b) Force or torque measurement should be performed in accordance with API 6A, F.2.2.2.1, except that the measurement should be conducted twice with 100 % RWP pressure differential, once from below and once from above.

   NOTE 2 The test fluid may be liquid.

c) Dynamic test cycles should be performed in accordance with API 6A, F.2.2.2.2, except that the reduced number of cycles and temperature should be maintained at 39 °F ± 4 °F (4 °C ± 2 °C) throughout testing.

   NOTE 3 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.

d) API 6A, F.2.2.2.3 and F.2.2.2.4 should not be performed.

e) Gas seat test should be performed in accordance with API 6A, F.2.2.2.5, except that it should be performed twice with the pressure differential, once from both above and once from below, and the temperature maintained at 39 °F ± 4 °F (4 °C ± 2 °C).

f) Low-pressure seat test should be performed in accordance with API 6A, F.2.2.2.6, except that it should be performed twice with the pressure differential, once from both above and once from below, and the temperature maintained at 39 °F ± 4 °F (4 °C ± 2 °C).

g) API 6A, F.2.2.2.7 through F.2.2.2.10 should not be performed.

h) Body pressure/temperature cycles should be performed in accordance with API 6A, F.2.2.2.11, except that steps F.1.11.3 a) through o) should be performed with the device remaining closed throughout and the test pressure applied from below.

i) Body pressure holding test should be performed in accordance with API 6A, F.2.2.2.12, except that the temperature should be maintained at 39 °F ± 4 °F (4 °C ± 2 °C).

j) Gas seat test should be performed in accordance with API 6A, F.2.2.2.13, except that it should be performed twice with the pressure differential, once from both above and once from below, and the temperature maintained at 39 °F ± 4 °F (4 °C ± 2 °C).

k) API 6A, F.2.2.2.14 should not be performed.

l) Low-pressure seat test should be performed in accordance with API 6A, F.2.2.2.15, except that it should be performed twice with pressure differential, once from both above and once from below, and the temperature maintained at 39 °F ± 4 °F (4 °C ± 2 °C).

m) Force or torque measurement should be performed in accordance with API 6A, F.2.2.2.16, except that the measurement should be conducted twice with 100 % RWP pressure differential, once from below and once from above.

NOTE 4 The test fluid may be liquid.

Q.4.5.4

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.

Q.4.5.5

It should be demonstrated that the annulus isolation device, including the actuating mechanism, functions at the design water depth.

Q.4.5.6

Acceptance criteria for all gas stages of validation should be in accordance with 5.4.6.2.3 PSL 3G for equipment for pressure-containing seals, and in accordance with API 6A, F.1.6.2 for pressure-controlling seals.

Q.4.6 Chokes

Q.4.6.1

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

a) maintenance;

b) addition of lubricant or sealant;

c) replacement of any seals or components for the duration of the testing.

Q.4.6.2

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

Q.4.6.3

The choke valve validation testing should meet API 17D requirements as described in a) through e) (see Table Q.2).

a) Before performing all the steps described in b) though d), the choke valve should undergo FAT including a gas body test in accordance with 5.4.6.3.

b) PR2 sequence should performed in accordance with API 6A, F.2.4 for PR2F chokes.

NOTE 1 This satisfies 200 of the 500 endurance cycles and the 3 temperature cycles required by Table 3.

c) 200 hyperbaric cycles should performed in accordance with Annex N.

NOTE 2 This satisfies the 200 pressure/load cycles and 200 of the 500 endurance cycles required by Table 3.

d) 100 endurance cycles should performed in accordance with API 6A, F.2.4.4 except that the number of cycles should be 100.

NOTE 3 This completes the 500 endurance cycles required by Table 3.

e) After performing all testing described in a) through d), choke valve should undergo a gas body test in accordance with 5.4.6.3.

Q.4.7 Choke Actuators

Q.4.7.1

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.

Q.4.7.2

Choke actuator seals should be tested in accordance with API 17D.

Q.4.7.2

The choke position indicator should be verified for accurate position reading.

Q.4.7.2

Both mechanical and electrical (if applicable) indicator function should be verified.

NOTE As used in the following sections the term "endurance cycle" follows the definition for PR2F actuators (open-close-open) and "choke actuator endurance cycle" follows the definition of Table 5 footnote e (full-open to full-close or full-close to full-open).

Q.4.7.3

The choke actuator validation testing should meet API 17D requirements as described in a) through e) (see Table Q.3).

a) Before performing all the steps described in b) through d), the choke actuator should undergo FAT and hydrotest at 20 % and 100 % of the RWP of the actuator, as described in 7.20.3.5.

b) PR2 sequence should be performed in accordance with API 6A, F.2.3 for PR2F actuators.

NOTE 1 This satisfies 400 of the 1000 choke actuator endurance cycles and the 3 temperature cycles required by Table 5.

c) 200 hyperbaric cycles should performed in accordance with Annex N.

NOTE 2 This satisfies the 200 pressure/load cycles and 400 of the 1000 choke actuator endurance cycles required by Table 5.

d) 100 endurance cycles should be performed in accordance with API 6A, F.2.3.2.4, except that the number of cycles should be 100.

NOTE 3 This satisfies the 200 of the 1000 choke actuator endurance cycles required by Table 5.

e) After performing all the steps described in a) through d), the actuator should undergo FAT and hydrotest at 20 % and 100 % of the RWP of the actuator, as described in 7.20.3.5.

Q.5 Product Family Validation

Q.5.1

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.

Q.5.2

Validation of product family by API 17D scaling methods should only be used 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.

Q.6 Documentation

Q.6.1

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).

Q.6.2

Validation testing documentation should include the following:

a) validation test procedure;

b) test charts;

c) photographs and/or video of testing/equipment;

d) signatures of testing technicians and witnesses;

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

f) general assembly drawings of all equipment, including test equipment;

g) stack-up drawing of test setup;

k) validation testing report;

l) dimensional report of all critical parts before and after testing.

Table Q.1—Interpretation of API 17D, Table 5 Cycles for Valves and Valve Actuators

API 17D, Table 5 Requirement for Valves and Valves 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.2.2 Design validation for PR2F valves 200 cycles + 3 temperature cycles	API 17D, Annex N Hyperbaric testing 200 cycles	API 6A, F.2.2.2.2.1 Modified endurance cycling test 200 cycles
	Number of API 17D, Table 5 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.2.2 Design validation for PR2F valves 200 cycles + 3 temperature cycles	API 17D Annex N 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 5 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.2.3 Design validation for PR2F actuators 200 cycles + 3 temperature cycles	API 17D, Annex N Hyperbaric testing 200 cycles	API 6A, F.2.3.2.2 Modified endurance cycling test 200 cycles
	Number of API 17D, Table 5 cycles accumulated for each test	200 endurance cycles 3 temperature cycles	200 endurance cycles 200 pressure/load cycles	200 endurance cycles

Table Q.2—Interpretation of API 17D, Table 5 Cycles for Choke Valves

API 17D, Table 5 Requirement for Choke Valves		**Pressure/Load Cycling Test**	**Temperature Cycling Test**	**Endurance Cycling Test (Total Cumulative Cycles)**
		200	**3**	**500**
To be satisfied by:				
Choke valves	Validation test	API 6A, F.2.4 Design validation for PR2F chokes 200 cycles + 3 temperature cycles	API 17D, Annex N Hyperbaric testing 200 cycles	API 6A, F.2.4.4 Modified endurance cycling test 100 cycles
	Number of API 17D, Table 5 cycles accumulated for each test	200 endurance cycles 3 temperature cycles	200 endurance cycles 200 pressure/load cycles	100 endurance cycles

Table Q.3—Interpretation of API 17D, Table 5 Cycles for Choke Valve Actuators

API 17D, Table 5 Requirement for Choke Valve Actuators		**Pressure/Load Cycling Test**	**Temperature Cycling Test**	**Endurance Cycling Test (Total Cumulative Cycles)**
		200	**3**	**1000** **(Choke Actuator Endurance Cycles)**
To be satisfied by:				
Choke valve actuators	Validation test	API 6A, F.2.3 Design validation for PR2F actuators 200 cycles + 3 temperature cycles	API 17D, Annex N Hyperbaric testing 200 cycles	API 6A, F.2.3.2.2 Modified endurance cycling test 100 cycles
	Number of API 17D, Table 5 cycles accumulated for each test	400 choke actuator endurance cycles 3 temperature cycles	400 choke actuator endurance cycles 200 pressure/load cycles	200 choke actuator endurance cycles
	Additional testing	Further endurance cycles as per API 6A, F.2.3.2.2 except that the number of cycles should be performed to reach a cumulative one million actuator steps		

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