Supplement 2
June 1996

EFFECTIVE DATE: August 1, 1996

Specification for Subsea Wellhead and Christmas Tree Equipment

API SPECIFICATION 17D
FIRST EDITION, OCTOBER 30, 1992

American Petroleum Institute

Supplement 2 to Specification for Subsea Wellhead and Christmas Tree Equipment

This supplement covers changes to API Specification 17D (First Edition, October 30, 1992) adopted by letter ballot as well as editorial changes and changes from Supplement 1.

Page 10, Section 102.1. In equipment list headed by "Equipment which is beyond the scope of this specification", add as the first item:

Horizontal Tree Assemblies (individual components are covered as listed above).

Page 10, Section 102.1. In the equipment list headed by "Equipment which is beyond the scope of this specification", delete the following:

Guidelineless Systems

Page 10, Section 102.1. Under Subsea Trees list, replace Flowline Connector Systems with:

Tree-Mounted Flowline Connector

Page 17, Table 104.1. In reference No. 41. delete the following:

Third Edition.

Page 17, Table 104.1. Add to front of title:

Det norske

Page 21, Section 302.1a. After the first sentence, insert the following:

Where small diameter lines such as SCSSV control lines or chemical injection lines pass through a cavity, such as the tree/tubing hanger cavity, equipment bounding that cavity shall be rated for the maximum pressure in any of the lines, unless a means is provided to monitor and relieve the cavity pressure in the event of a leak in any of those lines.

Page 21, Section 302.1a. After the first sentence, insert the following:

For the purposes of this document, pressure ratings shall be interpreted as differential pressure. For clarity, the following examples are offered:

1. API 17D pressure containing components (such as bodies, bonnets and end connectors) rated for 10,000 psi (69.0 MPa) are tested and marked for 10,000 psi (69.0 MPa) differential pressure service. If the application is in a water depth that results in 2,500 psi (17.25 MPa) external ambient pressure, these components could be used up to a shut-in pressure of 12,500 psi (86.25 MPa), even though their maximum rated working pressure is marked as 10,000 psi (69.0 MPa).
2. API 17D pressure controlling components (such as valve bore sealing mechanisms and tubing plugs) may be isolated from the external ambient pressure under certain operating conditions. For example, valves on a subsea gas well may have little or no pressure on the

"downstream" side of their gates when the valves are closed and the flowline pressure is vented to atmosphere. In such cases, external ambient seawater pressure would not reduce the "differential pressure" acting across the valve bore sealing mechanism. Thus, in most cases, valves in subsea gas service cannot be used in applications where shut-in pressures would exceed the maximum rated working pressure stamped on the equipment.

3. API 17D pressure controlling components (such as valve bore sealing mechanisms and tubing plugs) on subsea oil wells may benefit from "external" downstream pressure due to the hydrostatic head of the oil column in the flowline. In such cases, the equipment could be used at pressures above the marked pressure rating. For example, if a 10,000 psi (69.0 MPa) rated valve is used in a water depth that results in 1750 psi (12.08 MPa) minimum hydrostatic pressure downstream of the valve, the valve could be used up to a shut-in pressure of 11,750 psi (81.08 MPa).

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

Page 21, Section 302.1c. Delete the following clause from the first sentence:

which could retain SCSSV control system pressure in the event of a control fluid leak

Page 21, Section 302.1f. Add the following to the end of the first sentence:

, or per the manufacturer's written specification.

Page 21, Section 302.1f. Change the last sentence to read as follows:

Hydraulic control circuits for SCSSV shall have standard working pressures of 5,000, 7,500, 10,000, 12,500 or 15,000 psi (34.5, 49.5, 69.0, 86.3, or 103.5 MPa), or per manufacturer's written specification.

Page 26, Section 403. Replace with the following:

403 PRODUCT SPECIFICATION LEVEL

The materials used in equipment covered by this specification shall comply with requirements of PSL 2 or PSL 3 as established in API Specification 6A.

Page 27, Section 701. At the end of the second paragraph, ending "may also be marked as '17D' tree assemblies" add the following:

(API licenses may additionally mark as shown in Appendix H of this specification).

Page 27, Section 704, third paragraph. Change Section 302.3c to Section 302.2c.

Page 31, Table 901.2. The Maximum Bore, "B" dimension, for the 3-1/8 inch flange changes. Delete 3.09 in. (78.5 mm) and replace with:

3.12 in. (79.3 mm)

Pages 33, 34, 35, and 36, Tables 901.3 and 901.4. Replace the two tables with new Tables 901.3 and 901.4 found in this supplement.

Page 37, Table 901.5. Change Width of Groove, dimension "B," for Ring Number BX-169 from 0.842 in. (21.39 mm) to:

0.942 in. (23.9 mm)

Pages 38 and 39, Tables 906.1 and 906.2. Lists of tolerances are transposed. Add to Table 906.1:

Note 3: The list of tolerances in Table 906.1 apply to Table 906.2; and the list in Table 906.2 applies to Table 906.1.

Page 39, Table 906.2. Add:

Note 2: The list of tolerances in Table 906.1 apply to Table 906.2; and the list in Table 906.2 applies to Table 906.1.

Page 40, Section 901.2d. Change the second sentence to read as follows:

If API 6A segmented flanges are used, there shall be at least two pressure controlling valves between the segmented flange and the wellhead.

Page 40, Section 901.2d. Replace the third sentence with the following:

Segmented flanges for use on subsea completion equipment which comply with the requirements of Sections 300 and 904 of this specification do not require the use of two pressure controlling valves between the segmented flange and the wellhead.

Page 40, Paragraph 901.2e(1). To clarify the purpose of the retainer groove on the 17SV flange, after the first sentence add the following:

A retainer groove is provided on the neck of the hub to allow installation of a snap wire of sufficient diameter to hold the ring on the hub during storage, handling and installation.

Page 41, Paragraph 901.3. Replace paragraph with the following:

901.3 MATERIALS. Flange material shall conform to the requirements in Sections 400 and 500 of this specification as applicable, and materials with a minimum yield strength of 75,000 psi (517 MPa) shall be used for Type 17SV Flanges for 10,000 psi (69.0 MPa) rated working pressure.

Page 43, Section 907.1a(2), NOTE TO USER: Delete the word "should" and replace it with

shall

Page 43, Section 907.1a(2), NOTE TO USER: Add the following phrase to the end of the sentence:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 43, Section 907.1b(2). Add to the last sentence:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 45, Section 908.2a(1). Add to the end of the third paragraph:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 53, Section 912.2b. Add to the end of the second bullet:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 53, Section 912.2c(2). Add to the end of the NOTE TO USER:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 53, Section 912.2c(3). Add to the first sentence of NOTE TO USER:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 56, Section 915.1. In the first sentence: replace "...flowline connector systems" with:

... tree-mounted flowline connector systems

Page 56, Section 915.1. Delete the last sentence.

Page 62, Section 919.3b(3)(a). Add the following to the end of the sentence:

, or per the manufacturer's written specification.

Page 83, Section 1001.5b(4) Change "(see Section 1002.2d)" to:

(see Sections 302.1a and 1002.2d of this specification).

Page 86, Section 1002.2d. Add the following to the first sentence:

..., unless relief is provided as described in Section 302.1a of this specification.

Page 109, Appendix D. Replace the existing Appendix D with the revised Appendix D found in this supplement.

Page 116, Appendix H. Add the following new paragraph after existing text:

Horizontal tree assemblies are beyond the scope of API Specification 17D and may not be marked with the API Monogram. However, components of horizontal tree assemblies are covered as listed in Section 102.1 and may be marked with the API Monogram if they comply with all applicable requirements of Specification 17D.

The 17th Edition of API Specification 6A has changed its numbering system considerably, so that all the specific Specification 6A references in API Specification 17D are now incorrect. Following is a list of API Specification 17D sections that contain specific Specification 6A references. All specific Specification 6A section numbers should be deleted in these references.

301.4	606	908.5b(2)
302.1a	901.1 (two references)	919.2b
302.3a	901.2b(1)	919.3c(2)
302.3b (two references)	901.2b(2)(c)	919.4c(1)
303.2	901.2b(3)	922.4b
303.3	901.2c	1001.5d(2)
303.4	901.2d	1001.6b(2)
304.4	901.2f	1002.4b(1)
304.5	901.2h	1101.1
305	903	1101.2a
401	906.2c	Appendix A, Table A1, footnote
402	906.3a	Appendix E, E1
501	908.1a(2) (two references)	Appendix G, G2.2
502	908.2a(1)	Appendix H, H1
503	908.2a(2)(b)	
601	908.5b(1)	

APPENDIX D—PROCEDURE FOR THE APPLICATION OF A COATING SYSTEM

D.1 Scope

This appendix covers the application of a standard protective paint coating system for subsea equipment.

D.2 Purpose

The purpose of this protective coating procedure is to ensure the proper preparation of the material and proper application of the coating. There are a number of paint companies that manufacture high-quality two-part epoxy-polyamide or polyamine paints suitable to coat subsea equipment. This procedure describes how to apply this type of paint to the subsea equipment. This procedure describes only one of many acceptable coating systems and should be regarded as typical of how coating systems should be applied.

D.3 Surface Preparation

D.3.1 All surfaces to be coated shall be grit blasted to white metal finish in accordance with the following standards or equivalent.

a. NACE 2 (National Association of Corrosion Engineers).
b. SSPC-SP-10 (Steel Structures Painting Council).
c. SA-2 1/2 (Swedish standard).

D.3.2 Any oil and/or grease shall be removed with an appropriate solvent before priming.

D.3.3 Blast cleaning shall not be carried out on wet surfaces, nor shall blast cleaning be carried out when surfaces are less than 5°F (3°C) above dew point.

D.3.4 The compressed air supply used for blasting shall be supplied at a minimum pressure of 70 psi (0.5 MPa) free of water and oil.

D.3.5 No acid washes or other cleaning solutions shall be used on metal surfaces after they have been blasted. This includes inhibited washes intended to prevent rusting.

D.3.6 Surface laminations shall be ground out and weld splatter shall be removed. Other surface irregularities including rough capping, undercut, and slag, together with sharp or rough edges, fins, and burrs, shall be power wire brushed, ground, or chipped as necessary to render the substrate suitable for coating.

D.3.7 Areas that will not be painted and that require protection shall be adequately masked.

D.3.8 If any rust forms after initial blasting, the rusted surfaces shall be reblasted and cleaned prior to priming.

D.4 Priming

D.4.1 All sand and dust shall be blown from the surfaces to be primed with dry, oil-free compressed air or nitrogen gas.

D.4.2 The primer shall be applied with spray, preferably airless spray equipment.

D.4.3 Blast cleaned surfaces shall be coated with the specified primer within 4 hours after grit blasting.

D.4.4 The primer shall be applied within the relative humidity specified by the paint manufacturer.

D.5 Coating Systems

D.5.1

Primer—Polyamide or Polyamine or Polyamine Epoxy Primer: 2.5/4.0 mils DFT

Finish Coat—Polyamine Glass Flake Epoxy: 12/20 mils DFT

Note: All products used shall not contain heavy metals such as lead, chrome, etc.

D.5.2 Drying times between coats shall be strictly in accordance with the paint manufacturer's instructions.

D.5.3 All coatings shall be mixed, thinned, and applied in accordance with the manufacturer's instructions.

D.5.4 All products used shall meet all volatile organic compound (VOC) guidelines and regulations applicable in the country where the coating system is used.

D.5.5 Finish coat color for subsea equipment shall be any shade of yellow that falls between Munsell standard specification 2.5Y/8/12 and 10Y/9/12. (This color standard provides the best visibility underwater in regard to clarity and contrast.)

D.6 Touch Up of Coating System

All touch up coatings shall be the same manufacturer's materials as the original coatings. Where sandblasting is impractical, power wire brushing to remove all oxidation will be acceptable. Six inches (150 millimeter) around the damaged area may also be wire brushed or lightly sanded by hand to roughen the epoxy to promote adhesion.

D.6.1 Repair of Coating Damage Down to Metal

Clean area with solvent to remove all oil and grease; wire brush if shiny. If the manufacturer supplies a solvent that will assist in repair, apply the solvent to the coated areas adjacent to the damaged area. When the adjacent coating becomes tacky, apply the coating system described in Section 5.

D.6.2 Repair of Epoxy Coating Damage Non-Extending to Metal

Sandpaper and feather out area to be repaired. Clean off with dry oil-free compressed air or nitrogen gas. Apply to high solid epoxy coatings as necessary to achieve the original finish.

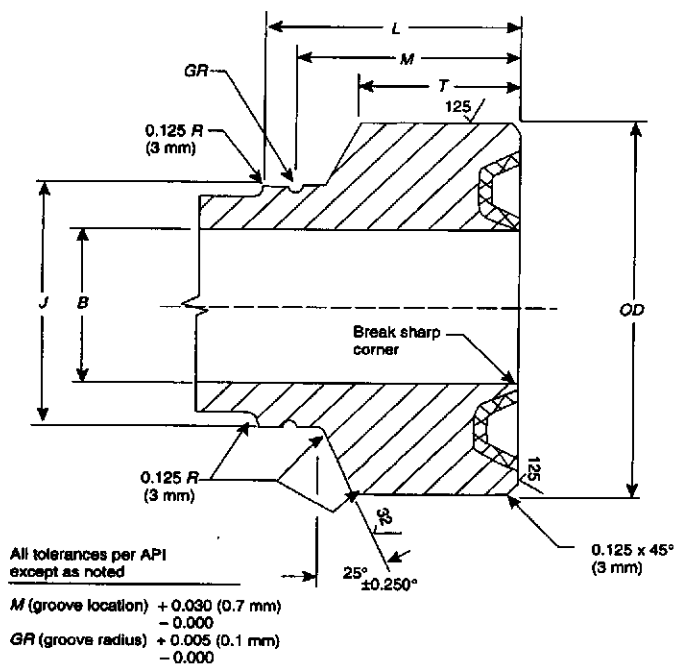
D.7 Inspection

D.7.1 A calibrated paint film thickness device shall be used to measure the dry film thickness at each stage of the painting process.

D.7.2 When dry film thicknesses are less than those specified, additional coatings shall be applied as necessary to achieve specified thickness.

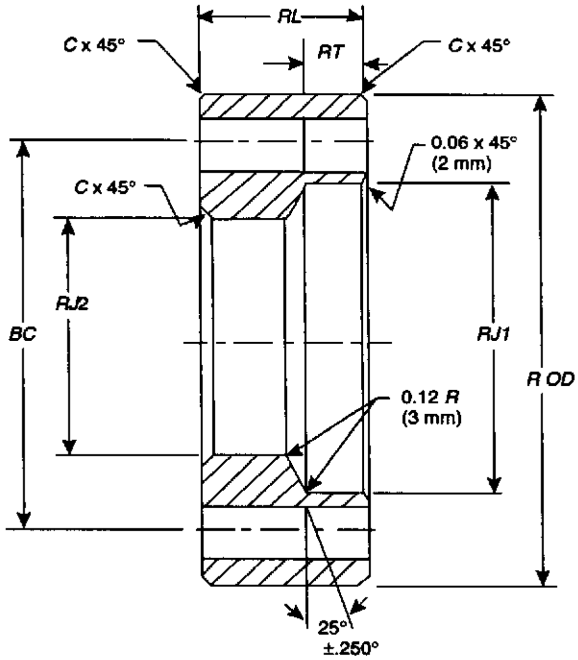
D.7.3 All coatings shall be free of pin holes, voids, bubbles and other holidays.

Table 901.3—Type 17SV Flanges for 5,000 psi (34.5 MPa) Rated Working Pressure



Nominal Size & Bore *B* (in.)	(mm)	Outside Diameter *OD* (in.)	(mm)	Total Thickness *T* (in.)	(mm)	Large Diameter of Neck *J* (in.)	(mm)	Length of Neck *L* (in.)	(mm)	Groove Location *M* (in.)	(mm)	Retainer Groove Radius *GR* (in.)	(mm)	Ring Gasket No. BX
						Hub Dimensions								
$2^1/_{16}$	52	5.031	128	1.166	29.5	3.656	93	3.282	84	2.907	74	0.13	3	152
$2^9/_{16}$	65	5.781	147	1.166	29.5	4.406	112	3.282	84	2.907	74	0.13	3	153
$3^1/_8$	78	6.312	160	1.166	29.5	4.938	126	3.432	88	3.067	78	0.13	3	154
$4^1/_{16}$	108	7.625	194	1.197	30.5	6.250	159	3.757	96	3.382	86	0.13	3	155
$5^1/_8$	130	9.380	240	1.410	36.0	7.755	197	4.732	121	4.357	111	0.13	3	169
$7^1/_{16}$	179	10.700	272	1.622	41.5	9.075	231	5.541	141	4.979	127	0.19	5	156
9	228	13.250	340	1.622	41.5	11.625	296	6.113	156	5.551	141	0.19	5	157
11	279	16.250	415	1.654	42.0	14.625	372	6.932	162	6.370	162	0.19	5	158

Table 901.3—Type 17SV Flanges for 5,000 (34.5 MPa) Rated Working Pressure (Continued)

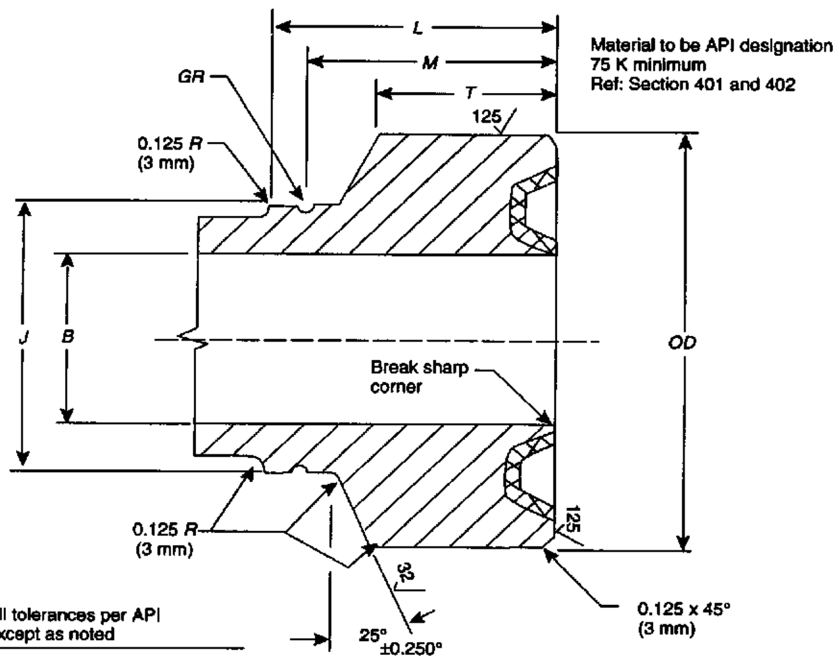


Tolerance:

R (outside diameter)	
Size 2-1/16 thru 5-1/8	±0.062 (2 mm)
Size 7-1/16 thru 11	±0.125 (3 mm)
RL (length of ring)	+0.125 (3 mm) –0.000
RT (depth of large diameter)	+0.062 (2 mm) –0.000
RJ1 (large ID ring)	+0.031 (1 mm) –0.000
RJ2 (small ID ring)	+0.031 (1 mm) –0.000
C (chamfer)	+0.010 (0.3 mm) –0.000
Bolt diameter	
Size 2-1/16 thru 7-1/16	+0.060 (2 mm) –0.020 (0.5 mm)
Size 9 thru 11	+ 0.090 (2.5 mm) –0.020 (0.5 mm)

Basic Dimensions of Ring																Bolts			
Nominal Size & Bore of Hub		OD of Ring *R OD*		Depth of Large ID *RT*		Large ID of Ring *RJ1*		Small ID of Ring *RJ2*		Length of Ring *RL*		Chamfer *C*		Diameter of Bolt Circle *BC*		Number of Bolts	Dia. of Bolt Holes	
(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)		(in.)	(mm)
2 1/16	52	8.50	216	0.964	24.5	5.093	129.4	3.718	94.5	2.450	63	0.125	3	6.50	165.1	8	1.00	26
2 9/16	65	9.62	246	0.964	24.5	5.843	148.5	4.468	113.5	2.450	63	0.125	3	7.50	190.5	8	1.12	29
3 1/8	78	10.50	267	0.964	24.5	6.375	162.0	5.000	127.0	2.600	66	0.125	3	8.00	203.2	8	1.25	32
4 1/16	103	12.25	312	0.965	25.3	7.687	195.3	6.312	160.4	2.925	75	0.125	3	9.50	241.3	8	1.38	36
5 1/8	130	14.75	375	1.208	30.7	9.442	239.9	7.817	198.6	3.900	99	0.125	3	11.50	292.1	8	1.62	42
7 1/16	179	15.50	394	1.420	36.1	10.762	273.4	9.157	232.1	4.459	114	0.188	5	12.50	317.5	12	1.50	39
9	228	19.00	483	1.420	36.1	13.312	338.2	11.687	296.9	5.031	128	0.188	5	15.50	393.7	12	1.75	45
11	279	23.00	585	1.452	36.9	16.312	414.4	14.687	373.1	5.850	149	0.188	5	19.00	482.6	12	2.00	51

Table 901.4—Type 17SV Flanges for 10,000 psi (69.0 MPa) Rated Working Pressure



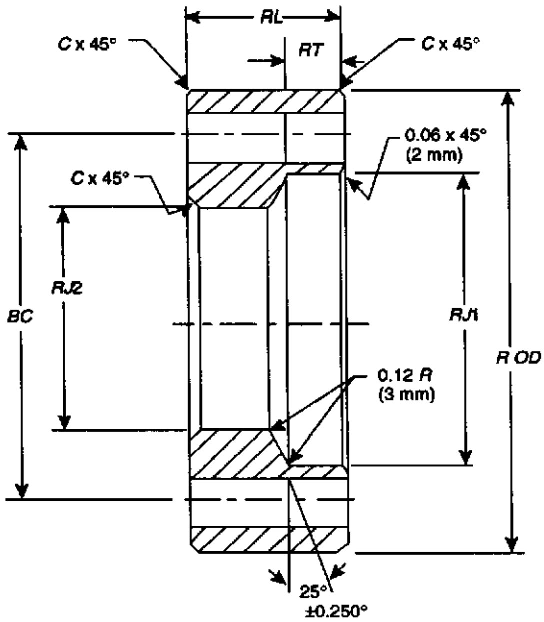
All tolerances per API except as noted

M (groove location) + 0.030 (0.7 mm) − 0.000
GR (groove radius) + 0.005 (0.1 mm) − 0.000

Hub Dimensions

Nominal Size & Bore (in.)	(mm)	Outside Diameter *OD* (in.)	(mm)	Total Thickness *T* (in.)	(mm)	Large Diameter of Neck *J* (in.)	(mm)	Length of Neck *L* (in.)	(mm)	Groove Location *M* (in.)	(mm)	Retainer Groove Radius *GR* (in.)	(mm)	Ring Gasket No. BX
$1^{13}/_{16}$	46	4.500	115	1.166	29.5	3.250	82.6	3.282	84	2.907	74	0.13	3	151
$2^{1}/_{16}$	52	5.000	130	1.166	29.5	3.750	95.3	3.282	84	2.907	74	0.13	3	152
$2^{9}/_{16}$	65	5.800	150	1.166	29.5	4.550	115.6	3.302	84	2.927	75	0.13	3	153
$3^{1}/_{16}$	78	6.930	175	1.197	30.5	5.680	144.3	3.666	94	3.291	84	0.13	3	154
$4^{1}/_{16}$	103	8.437	215	1.310	33.3	6.812	178.0	4.277	109	3.902	99	0.13	3	155
$5^{1}/_{8}$	130	9.960	225	1.500	38.1	8.335	211.7	4.732	121	4.357	111	0.13	3	169
$7^{1}/_{16}$	179	13.660	350	1.653	42.0	12.035	305.7	6.204	158	5.641	143	0.19	5	156
9	228	16.250	415	1.653	42.0	14.625	371.5	7.270	185	6.707	170	0.19	5	157
11	279	18.870	480	2.035	51.7	17.245	438.0	8.153	207	7.591	193	0.19	5	158
$13^{5}/_{8}$	346	22.250	565	2.309	58.7	20.625	523.9	9.531	242	8.969	228	0.19	5	159

Table 901.4—Type 17SV Flanges for 10,000 psi (69.0 MPa) Related Working Pressure (Continued)



Material to be API designation
75 K minimum
Ref: section 401 and 402

Tolerance:

R (outside diameter)	
Size 2-1/16 thru 5-1/8	±0.062 (2 mm)
Size 7-1/16 thru 11	±0.125 (3 mm)
RL (length of ring)	+0.125 (3 mm) −0.000
RT (depth of large diameter)	+0.062 (2 mm) −0.000
RJ1 (large ID ring)	+0.031 (1 mm) −0.000
RJ2 (small ID ring)	+0.031 (1 mm) −0.000
C (chamfer)	+0.010 (0.3 mm) −0.000
Bolt diameter	
Size 2-1/16 thru 7-1/16	+0.060 (2 mm) −0.020 (0.5 mm)
Size 9 thru 11	+ 0.090 (2.5 mm) −0.020 (0.5 mm)

		Basic Dimensions of Ring												Bolts				
Nominal Size & Bore of Hub		OD of Ring R OD		Depth of Large ID RT		Large ID of Ring RJ1		Small ID of Ring RJ2		Length of Ring RL		Chamfer C		Diameter of Bolt Circle BC		No. of Bolts	Dia. of Bolt Holes	
(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)	(in.)	(mm)		(in.)	(mm)
$1\,^{13}/_{16}$	46	7.38	188	0.964	24.5	4.562	115.9	3.312	84.1	2.450	63	0.125	3	5.75	146.1	8	0.88	23
$2\,^{1}/_{16}$	52	7.88	200	0.964	24.5	5.062	128.6	3.812	96.8	2.450	63	0.125	3	6.25	158.8	8	0.88	23
$2\,^{9}/_{16}$	65	9.12	232	0.964	24.5	5.862	148.9	4.612	117.1	2.470	63	0.125	3	7.25	184.1	8	1.00	26
$3\,^{1}/_{16}$	78	10.62	270	0.965	25.3	6.992	177.6	5.742	145.8	2.834	72	0.125	3	8.50	215.9	8	1.12	29
$4\,^{1}/_{16}$	103	12.44	316	1.108	28.1	8.500	215.9	6.875	174.6	3.445	88	0.125	3	10.19	258.8	8	1.25	32
$5\,^{1}/_{8}$	130	14.06	357	1.298	33.0	10.022	254.6	8.397	213.3	3.900	99	0.125	3	11.81	300.0	12	1.25	32
$7\,^{1}/_{16}$	179	18.88	480	1.451	36.9	13.722	348.5	12.097	307.3	5.122	130	0.188	5	15.88	403.4	12	1.62	42
9	228	21.75	552	1.451	36.9	16.312	409.7	14.687	373.0	6.188	158	0.188	5	18.75	496.3	16	1.62	42
11	279	25.75	654	1.833	46.6	18.932	480.9	17.307	439.6	7.072	180	0.188	5	22.25	565.2	16	1.88	48
$13\,^{5}/_{8}$	346	30.25	768	2.107	53.5	22.312	566.7	20.687	525.4	8.450	215	0.188	5	26.50	673.1	20	2.00	51

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Specification for Subsea Wellhead and Christmas Tree Equipment

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Foreword

This supplement covers changes in API Spec 17D, First Edition, October 30, 1992, adopted by letter ballot as well as editorial changes.

Page 17, Table 104.1. *Delete edition number in reference* No. 41.

Page 17, Table 104.1. *Add* "Det norske" *to front of title.*

Page 26, Section 403. *Replace with the following:*

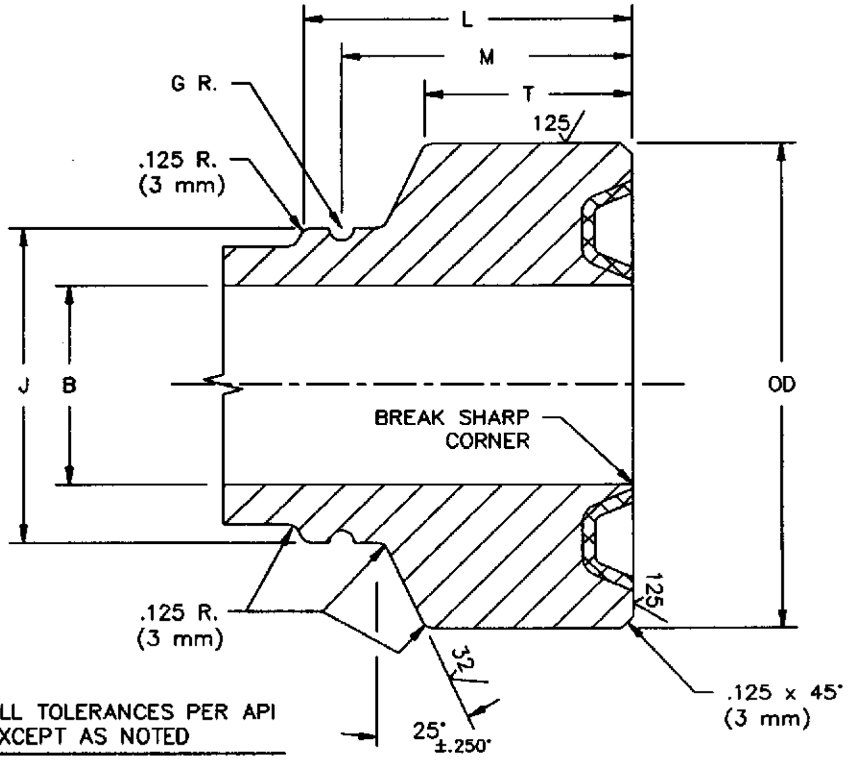
"**403 PRODUCT SPECIFICATION LEVEL.** The materials used in equipment covered by this specification shall comply with requirements of PSL 2 or PSL 3 as established in API Specification 6A."

Page 27, Section 704, third paragraph. *Change* "302.3c" *to* "302.2c".

Pages 33, 34, 35 and 36, Tables 901.3 and 901.4. *Replace the two tables with those on the following four pages.*

Attention Users of this Publication: Portions of this publication have been changed from the previous edition. The location of changes has been marked with a bar in the margin. In some cases the changes are significant, while in other cases the changes reflect minor editorial adjustments. The bar notations in the margins are provided as an aid to users to identify those parts of this publication that have been changed from the previous edition, but API makes no warranty as to the accuracy of such bar notations.

TABLE 901.3
Type 17SV Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure



ALL TOLERANCES PER API
EXCEPT AS NOTED

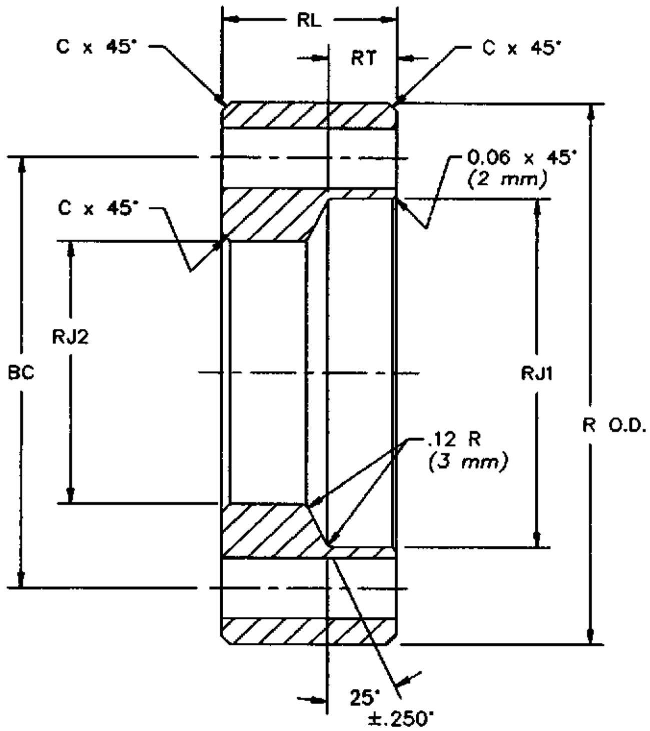
M (Groove Location) +.030 (0,7 mm) −.000

GR (Groove Radius) +.005 (0,1 mm) −.000

Hub Dimensions

Nominal Size and Bore B in. (mm)	Outside Dia. OD in. (mm)	Total Thickness T in. (mm)	Large Dia. of Neck J in. (mm)	Length of Neck L in. (mm)	Groove Location M in. (mm)	Retainer Groove Radius GR in. (mm)	Ring Gasket No. BX
2¹/₁₆ (52)	5.031 (128)	1.166 (29,5)	3.656 (93)	3.282 (84)	2.907 (74)	.125 (3,2)	152
2⁹/₁₆ (65)	5.781 (147)	1.166 (29,5)	4.406 (112)	3.282 (84)	2.907 (74)	.125 (3,2)	153
3⅛ (78)	6.312 (160)	1.166 (29,5)	4.938 (126)	3.432 (88)	3.067 (78)	.125 (3,2)	154
4¹/₁₆ (108)	7.625 (194)	1.197 (30,5)	6.250 (159)	3.757 (96)	3.382 (86)	.125 (3,2)	155
5⅛ (130)	9.380 (240)	1.410 (36,0)	7.755 (197)	4.732 (121)	4.357 (111)	.125 (3,2)	169
7¹/₁₆ (179)	10.700 (272)	1.622 (41,5)	9.075 (281)	5.541 (141)	4.979 (127)	.188 (4,8)	156
9 (228)	13.250 (340)	1.622 (41,5)	11.625 (296)	6.113 (156)	5.551 (141)	.188 (4,8)	157
11 (279)	16.250 (415)	1.654 (42,0)	14.625 (372)	6.932 (162)	6.370 (162)	.188 (4,8)	158

TABLE 901.3 (continued)
Type 17SV Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure

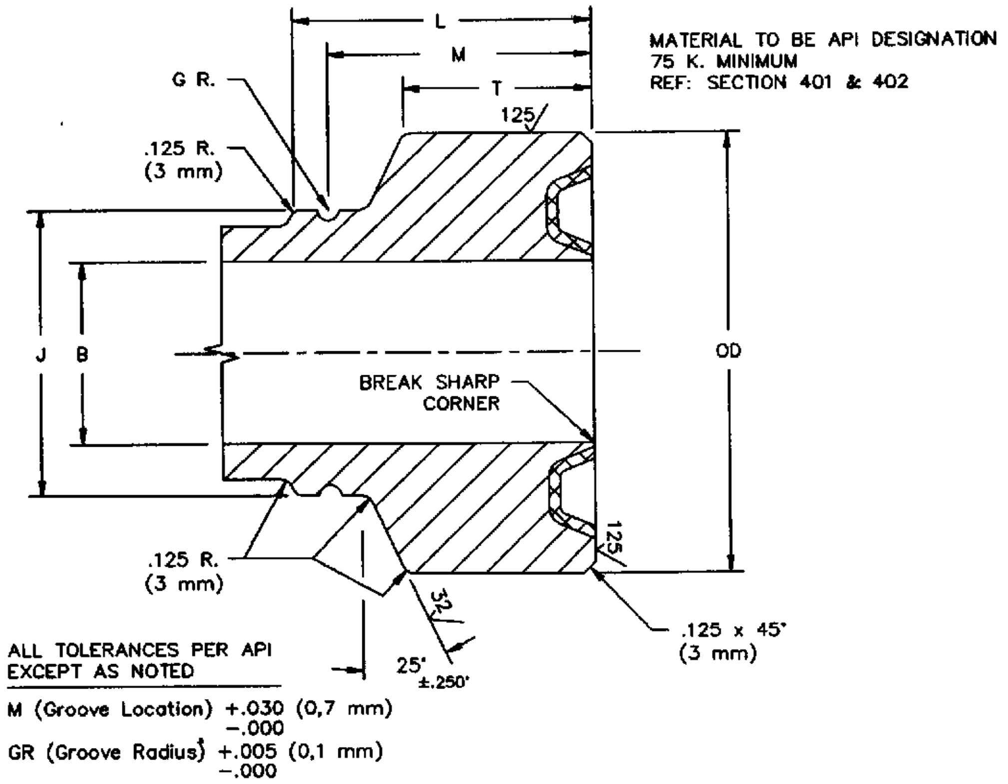


TOLERANCE:

R (Outside Dia.)		
Size 2 1/16 Thru 5 1/8	±.062	(2 mm)
Size 7 1/16 Thru 11	±.125	(3 mm)
RL (Length of Ring)	+.125 −.000	(3 mm)
RT (Depth of Large Dia.)	+.062 −.000	(2 mm)
RJ1 (Large I.D. Ring)	+.031 −.000	(1 mm)
RJ2 (Small I.D. Ring)	+.031 −.000	(1 mm)
C (Chamfer)	+.010 −.000	(0,3 mm)
Bolt Dia.		
Size 2 1/16 Thru 7 1/16	+.060 −.020	(2 mm) (0,5 mm)
Size 9 Thru 11	+.090 −.020	(2,5 mm) (0,5 mm)

Basic Dimensions of Ring							Bolts		
Nominal Size and Bore of Hub in. (mm)	Outside Dia. of Ring R OD in. (mm)	Depth of LG ID RT in. (mm)	Large ID of Ring RJ1 in. (mm)	Small ID of Ring RJ2 in. (mm)	Length of Ring RL in. (mm)	Chamfer C in. (mm)	Dia. of Bolt Circle BC in. (mm)	Number of Bolts	Dia. of Bolt Holes in. (mm)
2$\frac{1}{16}$ (52)	8.50 (216)	.964 (24,5)	5.093 (129,4)	3.718 (94,5)	2.450 (63)	.125 (3)	6.50 (165,1)	8	1.00 (26)
2$\frac{9}{16}$ (65)	9.62 (245)	.964 (24,5)	5.843 (148,5)	4.468 (113,5)	2.450 (63)	.125 (3)	7.50 (190,5)	8	1.12 (29)
3$\frac{1}{8}$ (78)	10.50 (267)	.964 (24,5)	6.375 (162,0)	5.000 (127,0)	2.600 (66)	.125 (3)	8.00 (203,2)	8	1.25 (32)
4$\frac{1}{16}$ (103)	12.25 (312)	.995 (25,3)	7.687 (195,3)	6.312 (160,4)	2.925 (49)	.125 (3)	9.50 (241,3)	8	1.38 (36)
5$\frac{1}{8}$ (130)	14.75 (375)	1.208 (30,7)	9.442 (239,9)	7.817 (198,6)	3.900 (99)	.125 (3)	11.50 (292,1)	8	1.62 (42)
7$\frac{1}{16}$ (179)	15.50 (394)	1.420 (36,1)	10.762 (273,4)	9.157 (232,1)	4.459 (114)	.188 (5)	12.50 (317,5)	12	1.50 (39)
9 (228)	19.00 (483)	1.420 (36,1)	13.312 (338,2)	11.687 (296,9)	5.031 (128)	.188 (5)	15.50 (393,7)	12	1.75 (45)
11 (279)	23.00 (585)	1.452 (36,9)	16.312 (414,4)	14.687 (373,1)	5.850 (149)	.188 (5)	19.00 (482,6)	12	2.00 (51)

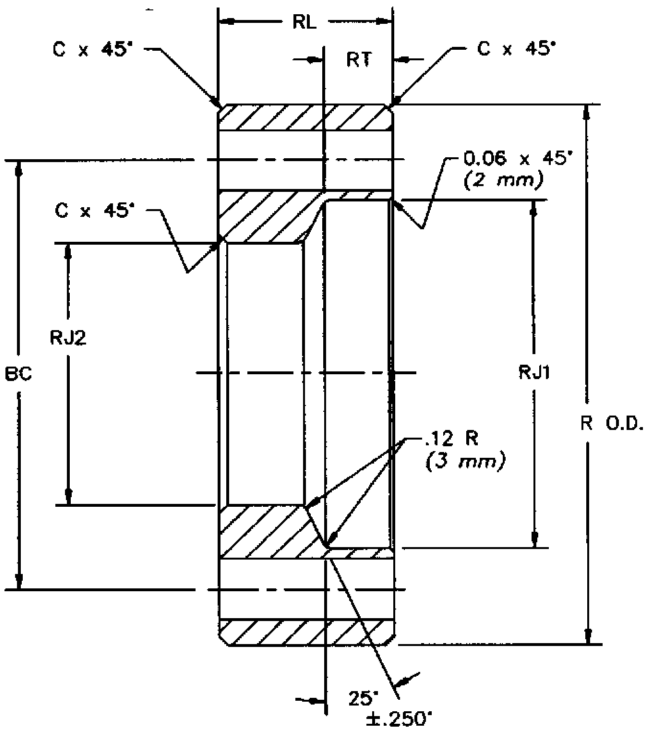
TABLE 901.4
Type 17SV Flanges for
10,000 psi (69,0 MPa) Rated Working Pressure



Hub Dimensions

Nominal Size and Bore in. (mm)	Outside Dia OD in. (mm)	Total Thickness T in. (mm)	Large Dia. of Neck J in. (mm)	Length of Neck L in. (mm)	Groove Location M in. (mm)	Retainer Groove Radius GR in. (mm)	Ring Gasket No. BX
1 13/16 (46)	4.500 (115)	1.166 (29,5)	3.250 (82,6)	3.282 (84)	2.907 (74)	.125 (3,2)	151
2 1/16 (52)	5.000 (130)	1.166 (29,5)	3.750 (95,3)	3.282 (84)	2.907 (74)	.125 (3,2)	152
2 9/16 (65)	5.800 (150)	1.166 (29,5)	4.550 (115,6)	3.302 (84)	2.927 (75)	.125 (3,2)	153
3 1/16 (78)	6.930 (175)	1.197 (30,5)	5.680 (144,3)	3.666 (94)	3.291 (84)	.125 (3,2)	154
4 1/16 (103)	8.437 (215)	1.310 (33,3)	6.812 (178,0)	4.277 (109)	3.902 (99)	.125 (3,2)	155
5 1/8 (130)	9.960 (255)	1.500 (38,1)	8.335 (211,7)	4.732 (121)	4.357 (111)	.125 (3,2)	169
7 1/16 (179)	13.660 (350)	1.653 (42,0)	12.035 (305,7)	6.204 (158)	5.641 (143)	.188 (4,8)	156
9 (228)	16.250 (415)	1.653 (42,0)	14.625 (371,5)	7.270 (185)	6.707 (170)	.188 (4,8)	157
11 (279)	18.870 (480)	2.035 (51,7)	17.245 (438,0)	8.153 (207)	7.591 (193)	.188 (4,8)	158
13 5/8 (346)	22.250 (565)	2.309 (58,7)	20.625 (523,9)	9.531 (242)	8.969 (228)	.188 (4,8)	159

TABLE 901.4 (continued)
Type 17SV Flanges for
10,000 psi (69,0 MPa) Rated Working Pressure



MATERIAL TO BE API DESIGNATION
75 K. MINIMUM
REF. SECTION 401 & 402

TOLERANCE:

R (Outside Dia.)		
Size 2 1/16 Thru 5 1/8	±.062	(2 mm)
Size 7 1/16 Thru 11	±.125	(3 mm)
RL (Length of Ring)	+.125 −.000	(3 mm)
RT (Depth of Large Dia.)	+.062 −.000	(2 mm)
RJ1 (Large I.D. Ring)	+.031 −.000	(1 mm)
RJ2 (Small I.D. Ring)	+.031 −.000	(1 mm)
C (Chamfer)	+.010 −.000	(0,3 mm)
Bolt Dia.		
Size 2 1/16 Thru 7 1/16	+.060 −.020	(2 mm) (0,5 mm)
Size 9 Thru 11	+.090 −.020	(2,5 mm) (0,5 mm)

Basic Dimensions of Ring								Bolts	
Nominal Size and Bore of Hub in. (mm)	Outside Dia. of Ring R OD in. (mm)	Depth of LG ID RT in. (mm)	Large I.D. of Ring RJ1 in. (mm)	Small ID of Ring RJ2 in. (mm)	Length of Ring RL in. (mm)	Chamfer C in. (mm)	Dia. of Bolt Circle BC in. (mm)	Number of Bolts	Dia. of Bolt Holes in. (mm)
1 13/16 (46)	7.38 (188)	.964 (24,5)	4.562 (115,9)	3.312 (84,1)	2.450 (63)	.125 (,3)	5.75 (146,1)	8	.88 (23)
2 1/16 (52)	7.88 (200)	.964 (24,5)	5.062 (128,6)	3.812 (96,8)	2.450 (63)	.125 (,3)	6.25 (158,8)	8	.88 (23)
2 9/16 (65)	9.12 (232)	.964 (24,5)	5.862 (148,9)	4.612 (117,1)	2.470 (63)	.125 (,3)	7.25 (184,1)	8	1.00 (26)
3 1/16 (78)	10.62 (270)	.995 (25,3)	6.992 (177,6)	5.742 (145,8)	2.834 (72)	.125 (,3)	8.50 (215,9)	8	1.12 (29)
4 1/16 (103)	12.44 (316)	1.108 (28,1)	8.500 (215,9)	6.875 (174,6)	3.445 (88)	.125 (,3)	10.19 (258,8)	8	1.25 (32)
5 1/8 (130)	14.06 (357)	1.298 (33,0)	10.022 (254,6)	8.397 (213,3)	3.900 (99)	.125 (,3)	11.81 (300,0)	12	1.25 (32)
7 1/16 (179)	18.88 (480)	1.451 (36,9)	13.722 (348,5)	12.097 (307,3)	5.122 (130)	.188 (,5)	15.88 (403,4)	12	1.62 (42)
9 (228)	21.75 (552)	1.451 (36,9)	16.312 (409,7)	14.687 (373,0)	6.188 (158)	.188 (,5)	18.75 (496,3)	16	1.62 (42)
11 (279)	25.75 (654)	1.833 (46,6)	18.932 (480,9)	17.307 (439,6)	7.072 (180)	.188 (,5)	22.25 (565,2)	16	1.88 (48)
13 5/8 (346)	30.25 (768)	2.107 (53,5)	22.312 (566,7)	20.687 (525,4)	8.450 (215)	1.88 (,5)	26.50 (673,1)	20	2.00 (51)

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Specification for Subsea Wellhead and Christmas Tree Equipment

API SPECIFICATION 17D (SPEC 17D)
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This standard shall become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

This is the first edition of API Spec 17D and was ratified by letter ballot.

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SECTION 100
SCOPE

101 PURPOSE. This specification was formulated to provide for the availability of safe, dimensionally and functionally interchangeable subsea wellhead, mudline, and tree equipment.

The technical content provides requirements for performance, design, materials, testing, inspection, welding, marking, handling, storing and shipping.

Critical components are those parts having requirements specified in this document.

Rework and repair of used equipment are beyond the scope of this specification.

102 APPLICATIONS.

102.1 EQUIPMENT. This specification covers subsea wellhead, mudline, and wet satellite tree equipment utilized for pressure control in both subsea production of oil and gas, and subsea injection services. Where applicable, this specification may also be used for such equipment on multiple well template applications. Equipment which is within the scope of this specification is listed as follows:

Subsea Trees

- Tree Connectors and Tubing Hanger Spools
- Valves, Valve Blocks, and Valve Actuators
- Chokes and Choke Actuators
- Through Flowline (TFL) Wye Spool
- Tree Upper Connection and Tree Cap
- Tree Piping
- Tree Guide Frames
- Tree Running Tools
- Tree Cap Running Tools
- Flowline Connector Systems
- Control Pod Running/Retrieval and Testing Tools
- Flowline Base Running/Retrieval Tools
- Tree Mounted Control Interfaces

Subsea Wellheads

- Conductor Housings
- Wellhead Housings
- Casing Hangers
- Seal Assemblies
- Tubing Hangers
- Guidebases
- Bore Protectors and Wear Bushings
- Corrosion Caps

Mudline Suspension Systems

- Wellheads
- Tubing Hangers
- Running Tools
- Casing Hangers
- Casing Hanger Running Tool
- Tieback Tools for Subsea Completion
- Subsea Completion Adaptors for Mudline Wellheads
- Tubing Spools
- Corrosion Caps

Other Equipment

- Flanged End and Outlet Connections
- Clamp Hub-Type Connections
- Threaded End and Outlet Connections
- Other End Connections
- Studs and Nuts
- Ring Joint Gaskets
- Intervention Equipment
- Guideline Establishment Equipment

Equipment which is beyond the scope of this specification includes:

- Subsea Wireline/Coiled Tubing BOPs
- Workover and Production Risers
- Control Systems
- Guidelineless Systems
- Platform Tiebacks
- Protective Structures
- Subsea Process Equipment
- Subsea Manifolding
- Subsea Wellhead Tools
- Repair and Rework
- Multiple Well Template Structures
- Mudline Suspension High Pressure Risers
- Template Piping
- Template Interfaces

General information regarding all of these topics may be found in additional API publications, such as Recommended Practices 17A, 2C, and API Bulletin 2J.

The typical equipment nomenclature used in this specification is shown in Figures 102.1, 102.2, 102.3, 102.4, and 102.5.

Appendix A provides purchasing guidelines to users for API Specification 17D equipment.

102.2 SERVICE CONDITIONS.

102.2a General. Service conditions refer to classifications for pressure, temperature and the various wellbore constituents and operating conditions for which the equipment will be designed.

102.2b Pressure Ratings. Pressure ratings indicate maximum rated working pressures expressed as gage pressure (psig).

102.2c Temperature Ratings. Temperature ratings indicate temperature ranges, from minimum ambient to maximum flowing fluid temperatures, expressed in degrees Fahrenheit (°F).

102.2d Materials Class Ratings. Materials class ratings indicate the material of the equipment components. A guideline (not a requirement) for the basic wellbore constituents and operating conditions is covered in Appendix A.

103 PRODUCT SPECIFICATION LEVELS (PSL). All pressure containing and pressure controlling parts of equipment manufactured to Specification 17D shall comply with the requirements of PSL 2 or PSL 3 as established in API Specification 6A. These PSL designations define different levels of requirements. Appendix A provides guidelines (not requirements) for selecting an acceptable PSL.

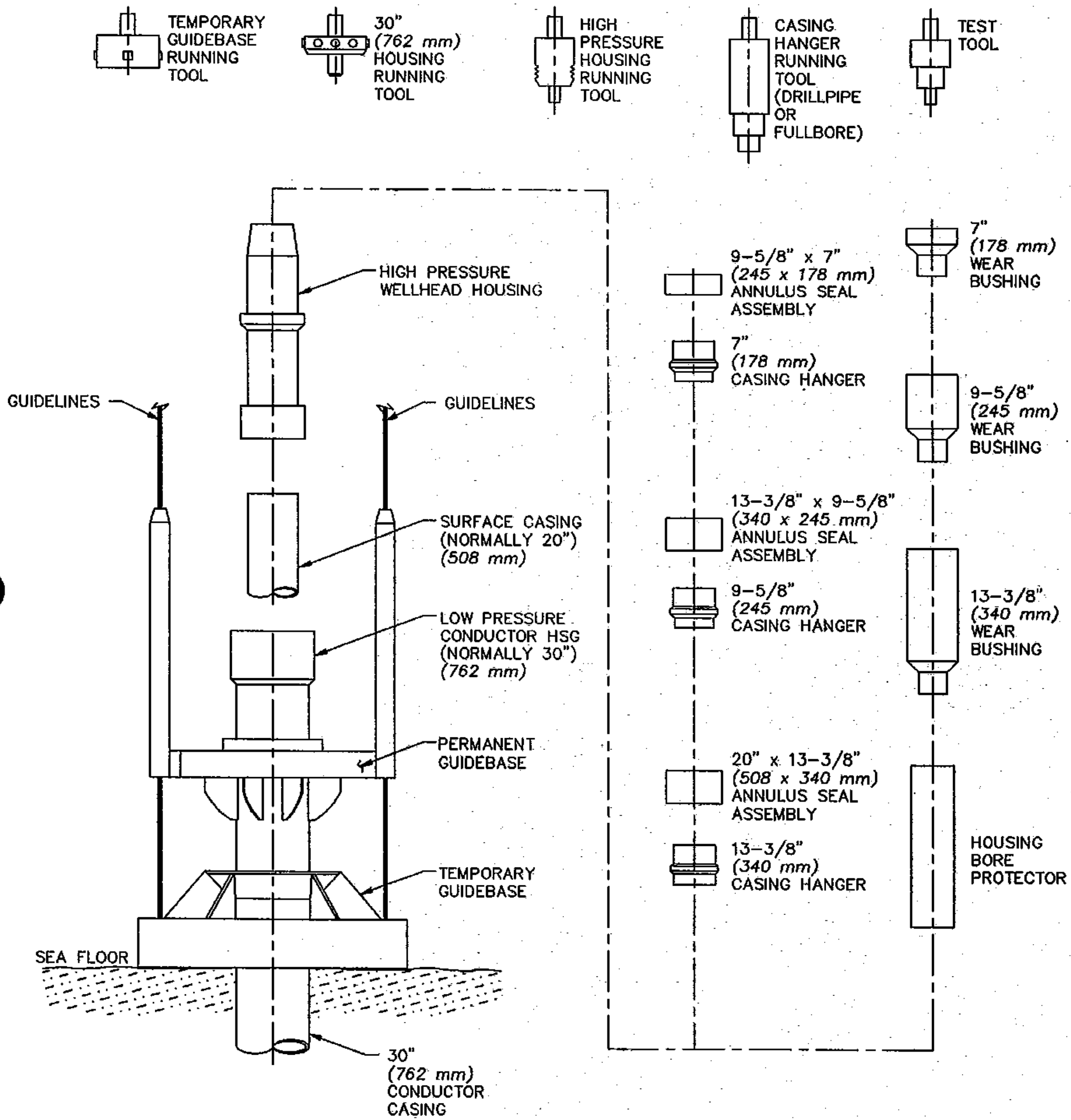


FIGURE 102.1
SUBSEA WELLHEAD SYSTEM

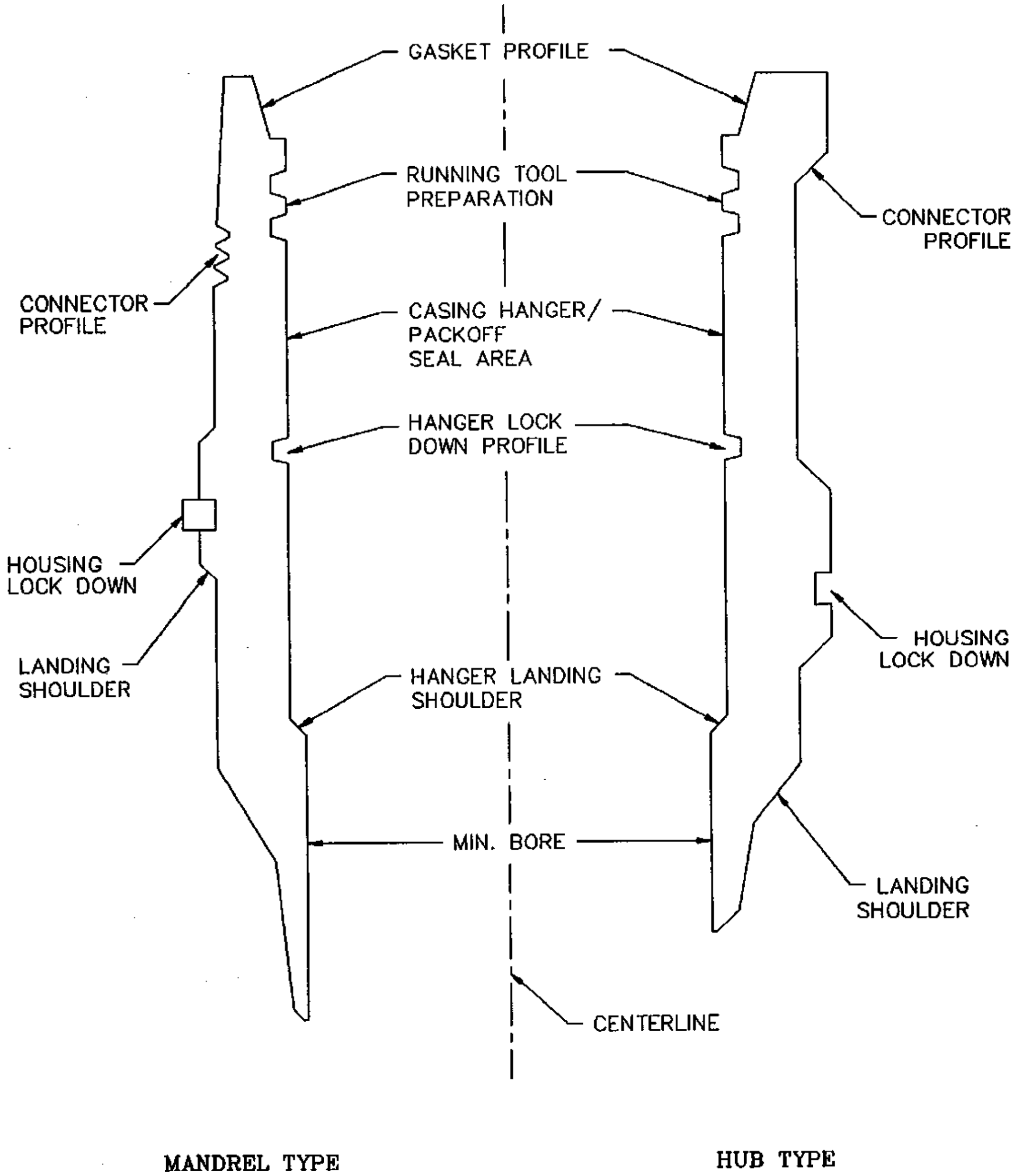


FIGURE 102.2
WELLHEAD HOUSINGS

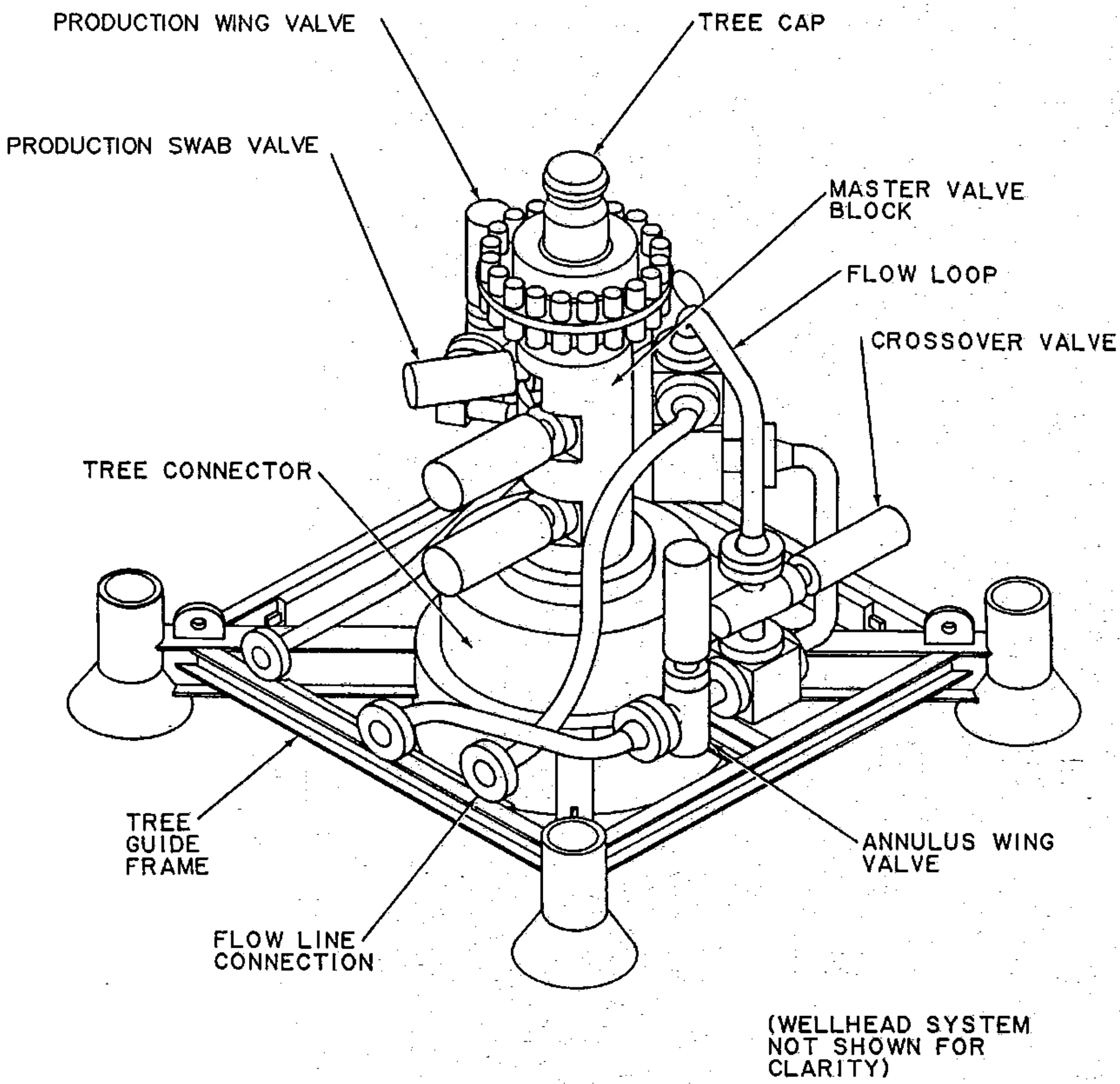


FIGURE 102.3
NON-TFL TREE

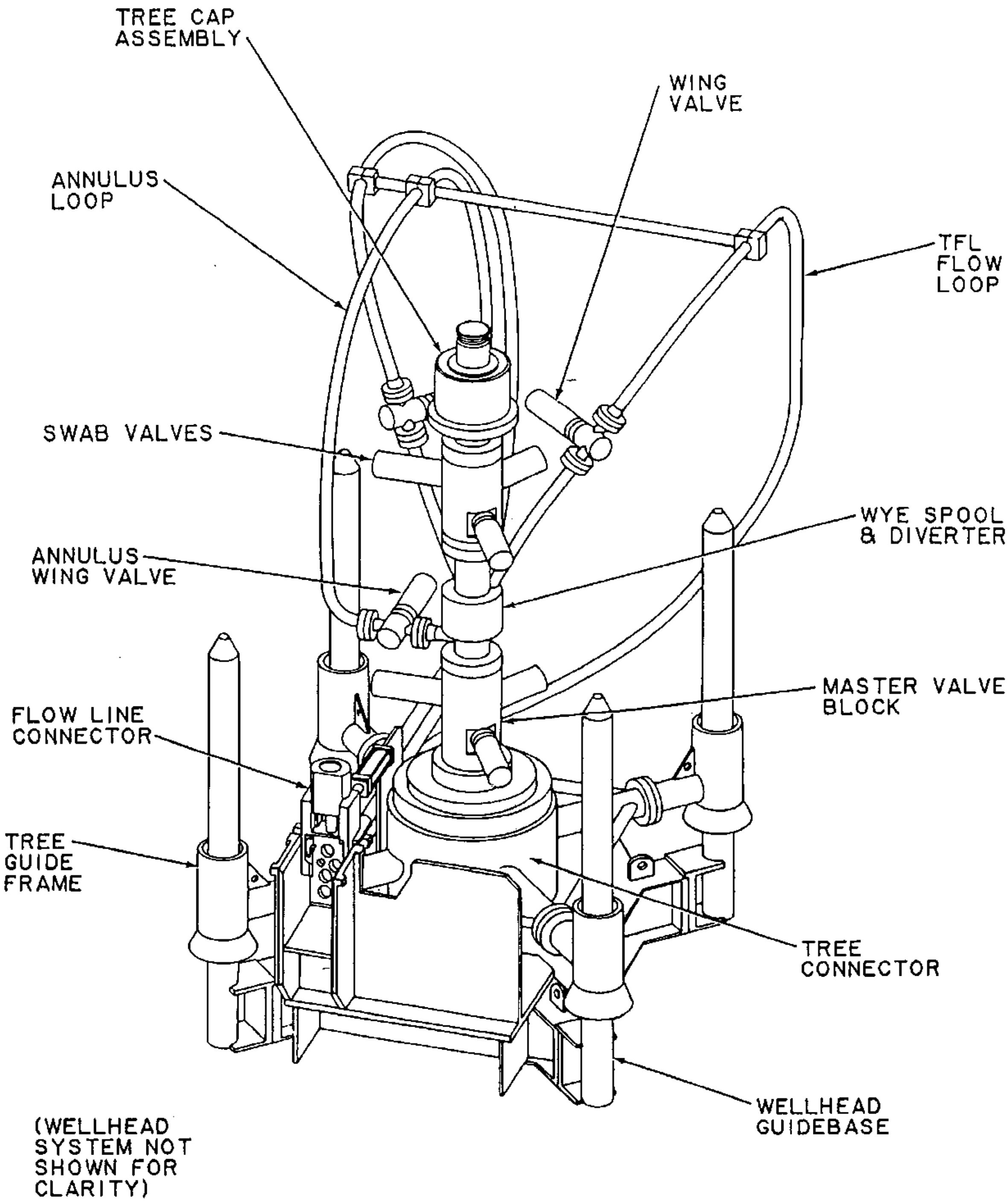


FIGURE 102.4
TFL TREE

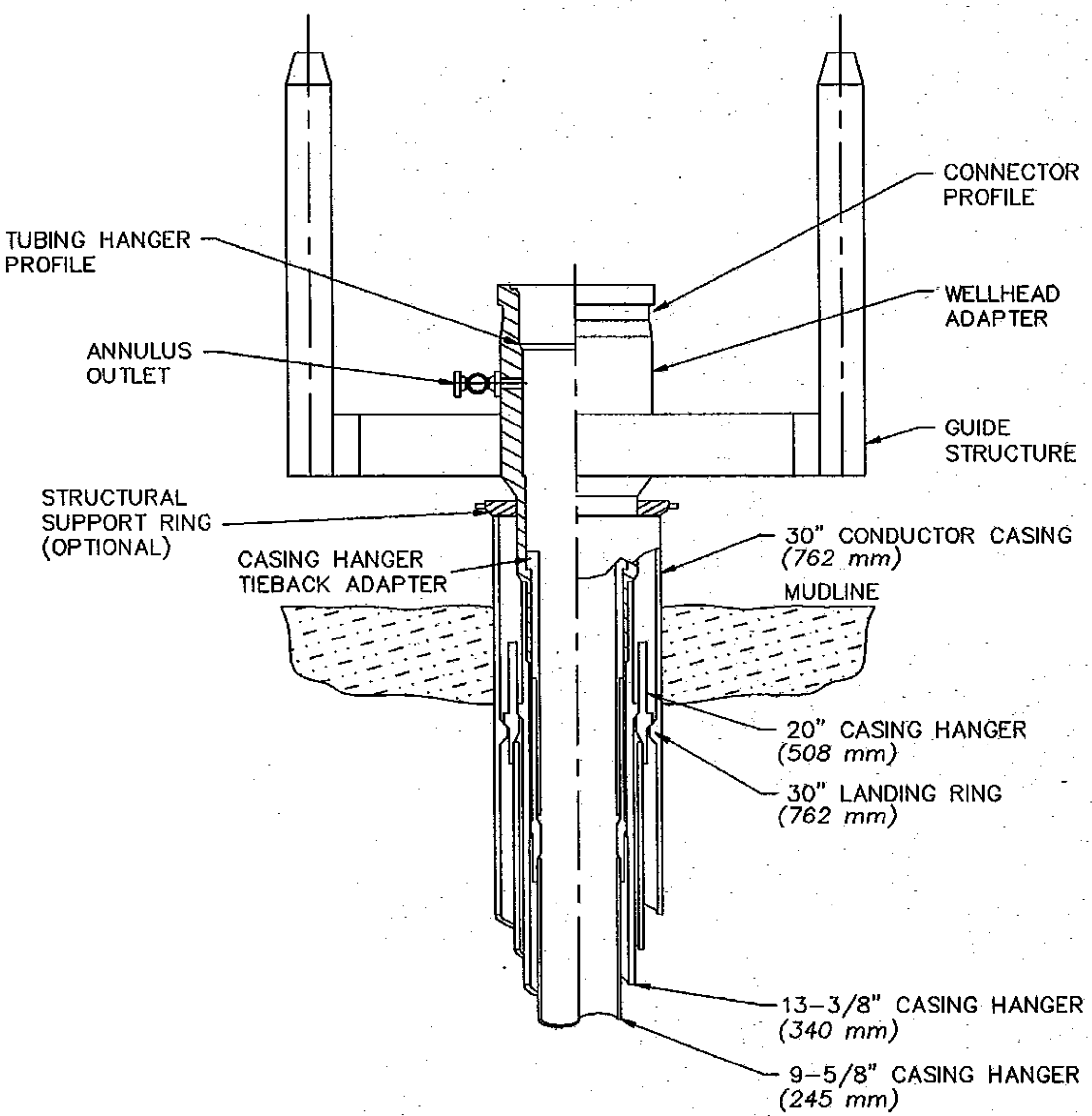


FIGURE 102.5
MUDLINE SYSTEM WITH WELLHEAD ADAPTOR AND CASING ADAPTORS INSTALLED

Structural components and other nonpressure containing/controlling parts of equipment manufactured to API Specification 17D need not comply with the requirements of PSL 2 or PSL 3. PSL rating of assembled wellhead or tree equipment shall be determined by the lowest PSL rating of any pressure containing/controlling component in the assembly.

104 REFERENCED STANDARDS.

104.1 GENERAL. This specification includes by reference, either in total or in part, the latest revision of other API, industry and government standards listed in Table 104.1 applicable at the time the order is placed. NOTE: *Only those standards listed in Table 104.1 are considered part of this specification. Documents (subtier) that are referenced by those standards are not considered part of this specification.*

104.2 REQUIREMENTS. Requirements of other standards included by reference in this specification are essential to the interchangeability of the equipment produced.

104.3 EQUIVALENT STANDARDS. Other nationally or internationally recognized standards shall be submitted to and approved by API for inclusion in this specification prior to their use as equivalent standards. For information on submitting equivalent standards for inclusion in this specification, contact the API Production Department, 2535 One Main Place, Dallas, Texas 75202-3904.

105 UNITS. A decimal/inch system is the standard for the dimensions shown in this specification. Nominal sizes will continue to be shown as fractions. This reflects current widespread industry practice. For the purposes of this specification, the fractions and their decimal equivalents are equal and interchangeable. Metric conversion rules are described in Appendix B and metric equivalents are given in the text for reference only.

106 APPENDIXES. Appendixes to this specification shall not be considered as requirements. Unless specified as a requirement in the body of this specification, appendixes are included only as guidelines or information.

TABLE 104.1

REFERENCED STANDARDS

1. ANSI B1.1: Unified Standard Inch Screw Threads
2. ANSI B1.2: Gages and Gaging for Unified Inch Screw Threads
3. ANSI B16.11: Forged Steel Fittings, Socket-Welding and Threaded
4. ANSI B18.2.2: Square Hex and Nuts
5. ANSI B31.3: Chemical Plant and Petroleum Refinery Piping
6. ANSI B31.4: Liquid Transporation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols
7. ANSI B31.8: Gas Transmission and Distribution Piping Systems
8. ANSI Y14.5M: Geometric Tolerances
9. API Spec 5CT: Casing and Tubing
10. API Spec 5D: Drill Pipe
11. API Std 5B: Threading, Gaging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads
12. API Spec 5L: Line Pipe
13. API Spec 6A: Wellhead and Tree Equipment
14. API Spec 14D: Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service
15. API GOT: Glossary of Oilfield Production Terminology
16. ASME Boiler and Pressure Vessel Code, Section V, Nondestructive Testing, Article 5, Examination Methods for Materials and Fabrication Para. T522 & T542
17. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1
    a) Part UG-101: Proof Tests to Establish Maximum Allowable Working Pressure
    b) Appendix 4: Rounded Indication Charts Acceptance Standard for Radiographically Determined Rounded Indications in Welds
18. ASME Section VIII, Division 2: Pressure Vessels — Alternate Rules
    a) Appendix 4: Design Based on Stress Analysis
    b) Appendix 6: Experimental Stress Analysis

TABLE 104.1

REFERENCE STANDARDS (Continued)

19. ASME Section IX: Welding and Brazing Qualifications ....
ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing. Qualifications. ....
20. ASTM A 193: Alloy Steel and Stainless Steel Bolting Materials for High Temperature Service
21. ASTM A 194: Carbon Alloy Steel Nuts for Bolts for High Pressure Temperature Service ....
22. ASTM A 307: Carbon Steel Externally Threaded Standard Fasteners ....
23. ASTM A 320: Alloy Steel Bolting Materials for Low Temperature Service ....
24. ASTM A 370: Standard Methods and Definitions for Mechanical Testing of Steel Products ......
25. ASTM A 388: Recommended Practice for Ultrasonic Examination of Heavy Steel Forgings ......
26. ASTM A 453: Bolting Materials, High Temperature, 50 to 129 ksi Yield Strength, with Expansion Coefficients Comparable to Austenitic Steels ....
27. ASTM A 609: Specification for Ultrasonic Examination for Carbon and Low-Alloy Steel Casings ....
28. ASTM E 10: Standard Test Methods for Brinell Hardness of Metallic Materials ....
29. ASTM E 18: Standard Test Methods for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials ....
30. ASTM E 92: Standard Test Method for Vickers Hardness of Metallic Materials ....
31. ASTM E 94: Standard Practice for Radiographic Testing ....
32. ASTM E 140: Standard Hardness Conversion Tables for Metals ....
33. ASTM E 165: Standard Practice for Liquid Penetrant Inspection ....
34. ASTM E 187: Standard Reference for Heavy Walled (2 to 4½ in.) (51 to 114 mm) Steel Casings ....
35. ASTM E 280: Standard Reference Radiographs for (4½ to 12 in.) (114 to 305 mm) Steel Casings ....
36. ASTM E 428: Standard Recommended Practice for Fabrication and Control of Steel Referenced Blocks Used in Ultrasonic Inspection ....
37. ASTM E 446: Standard Reference Radiographs for Steel Castings up to 2 in. in Thickness ......
38. ASTM E 709: Standard Recommended Practice for Magnetic Particle Examination ....
39. ASTM E 747: Standard Method for Controlling Quality of Radiographic Testing Using Wire Penetrameters ....
40. AWS DI.I: Structural Welding Code ....
41. ISA Handbook of Control Valves, Third Edition ....
42. MSS SP-55: Quality Standard for Steel Castings for Valves, Flanges and Fittings and other Piping Components (Visual Method) ....
43. MIL-STD-105D: Sampling Procedures and Tables for Inspection by Attributes ....
44. MIL-STD-120: Gage Inspection ....
45. NACE MR-01-75: Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment ....
46. NACE RP-01-76: Corrosion Control on Steel, Fixed Offshore Platforms Associated with Petroleum Production ....
47. PFI ES-24: Pipe Bending Methods, Tolerances, Process and Material Requirements ....
48. SAE J517: Standard for Hydraulic Hose ....
49. SAE J343: Tests and Procedures for SAE 100R Series Hydraulic Hose and Hose Assemblies ...
50. SNT-TC-1A: Personnel Qualification and Certification in Nondestructive Testing ....
51. ISA S75.02 ....
52. SSPC - SP10: Structural Steel Painting Council ....
53. Veritas Offshore Standard RP B401: Cathodic Protection Design ....

NOTE: *For information on Equivalent Standards, see Section 104.3.*

SECTION 200
ABBREVIATIONS/DEFINITIONS

201 ABBREVIATIONS.

@ — at

ADS — Atmospheric Diving System

AMV — Annulus Master Valve

ANSI — American National Standards Institute

API — American Petroleum Institute

ASV — Annulus Swab Valve

ASME — American Society of Mechanical Engineers

ASNT — American Society for Nondestructive Testing

ASTM — American Society for Testing and Materials

AWS — American Welding Society

AWV — Annulus Wing Valve

BOP — Blowout Preventor

cc — cubic centimeters

CIV — Chemical Injection Valve

CRA — Corrosion Resistant Alloys

CRM — Corrosion Resistant Material

degrees F — degrees Fahrenheit

GOT — Glossary of Oilfield Terminology

ID — inside diameter

J — Joule

LWRP — Lower Workover Riser Package

max — maximum

MIL-STD — Military Standard, U.S.A.

min — minimum

MLS — Mudline Suspension System

MPa — Mega Pascal SI Unit for Pressure

MSS — Maufacturers Standardization Society of The Valve and Fittings Industry

NACE — National Association of Corrosion Engineers

N-M — Newton Meter

NDE — non-destructive examination

OD — outside diameter

PGB — Permanent Guide Base

PMV — Production Master Valve

PR2 — Performance Requirement Level Two

PSV — Production Swab Valve

psi — pounds per square inch

psia — pounds per square inch absolute

psig — pounds per square inch gauge

PSL — Product Specification Level

PWV — Production Wing Valve

ROV — Remotely Operated Vehicle

S_b — Bending Stress

S_m — Membrane Stress

S_{yld} — Yield Stress

SCSSV — Surface Controlled Subsurface Safety Valve

Temp — temperature

TFL — Through Flowline Tools

TGB — Temporary Guide Base

WCT-BOP — Wireline/Coil Tubing Blowout Preventor

XOV — Crossover Valve

202 DEFINITIONS. The definitions listed herein are only those different from, or not included in, the Glossary of Oilfield Production Terminology (GOT). Where the GOT lists more than one definition for a term, the definition applicable to API Specification 6A shall apply.

Annulus Seal Assembly — A mechanism which provides pressure isolation between each casing hanger and the wellhead housing.

Bore Protector — A device which protects internal bore surfaces during drilling or workover operations.

Check Valve — A device designed to restrict flow in one direction.

Completion Riser — A riser that is designed to fit inside a BOP to allow installation of a tubing hanger, and may also be suitable for connection to the tree upper connection for use as a means for running the tree or for use as a workover riser (see workover riser).

Concentric Bore Tubing Hanger — A tubing hanger where the production bore is concentric with the O.D. of the hanger, normally requiring no orientation during installation.

Conductor Housing — The top of the first casing string which forms the basic foundation of the subsea wellhead and provides attachments for guidance structures.

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

Corrosion Resistant Alloys (CRA) — Nonferrous alloys where any one or the sum of the specified amount of the following alloy elements exceeds 50%: titanium, nickel, cobalt, chromium, and molybdenum.

Corrosion Resistant Materials (CRM) — Ferrous or nonferrous alloys which are more corrosion resistant than low alloy steels. This term includes CRA's, duplex, and stainless steels.

Depth Rating — The maximum rated working depth of a piece of equipment at a given set of operating conditions.

Downstream — Direction of movement away from the reservoir.

Extension Sub — Sealing tubular member that provides tree bore continuity between adjacent tree components.

Fail Closed Valve — An actuated valve designed to fail to the closed position.

Fail Open Valve — An actuated valve designed to fail to the open position.

First End Connection — The connection made at the initiation of the pipelaying process.

Flowline — Any pipeline connecting to the subsea tree assembly.

Flowline Connector Support Frame — A structural frame which receives and supports the flowline connector and transfers flowline loads back into the wellhead structure.

Flowline Connector System — The equipment used to attach subsea pipelines and/or control umbilicals to a subsea tree. The system may include means to guide the end of the pipeline or umbilical into place and may include remote connection or disconnection capability.

Flow Loops — Piping which connects the outlet(s) of the subsea tree to the subsea flowline connection and/or to other tree piping connections (crossover piping, etc.).

Guide Funnel — Tapered enlargement at the end of a guidance member to provide primary guidance over another guidance member.

Guidelineless Systems — Systems which do not depend on the establishment of guidelines from the seafloor to the surface vessel for guidance and alignment of subsea equipment during installation, operation, intervention, or retrieval.

Guidelines — Taut lines from the seafloor to the surface for the purpose of guiding equipment to the seafloor structure.

High Pressure Riser — A tubular member which extends the wellbore from the mudline tubing spool to a surface BOP.

Inboard Tree Piping — Subsea tree piping which is upstream of the first tree wing valve.

Intervention Fixtures — Devices or features permanently fitted to subsea well equipment to facilitate subsea intervention tasks including, but not limited to:

grasping intervention fixtures
docking intervention fixtures
landing intervention fixtures
linear actuator intervention fixtures
rotary actuator intervention fixtures
fluid coupling intervention fixtures

Intervention System — Means to deploy or convey intervention tools to subsea well equipment to carry out intervention tasks including:

remotely operated vehicle (ROV)
atmospheric diving system (ADS)
diver

Intervention Tools — A device or remotely operated tool deployed by an intervention system to mate or interface with intervention fixtures.

Lower Workover Riser Package (LWRP) — A unitized assembly that interfaces with the tree upper connection and allows sealing of the tree production bore(s). May also allow disconnect from the top connection of the LWRP, to permit retrieval of the workover riser, while wireline equipment is in the tree bore(s).

Misalignment Connections — Special connection devices which allow lateral, angular, and/or rotational misalignment between the fluid containing components being connected, sometimes used to facilitate connection of pipelines to subsea trees.

Moon Pool — A central passage directly under the rotary table in a floating vessel through which subsea equipment may be lowered into place or retrieved to the surface.

Mudline Suspension System (MLS) — A drilling system consisting of a series of housings used to support casing strings at the mudline, installed from a bottom-supported rig using a surface BOP.

Nonpressure Containing/Controlling Parts — Structural and other parts that do not contain or control pressure, such as guidebases, guideframes, and wear bushings.

Oriented Tubing Hangers — A tubing hanger having two or more separate parallel bores and requiring orientation during installation.

Orienting Bushings — Nonpressure containing parts which are used to orient equipment or tools with respect to the wellhead.

Outboard Tree Piping — Subsea tree piping which is downstream of the first tree wing valve and upstream of flowline connector (see flow loop).

Permanent Guidebase — A structure that sets alignment and orientation of the wellhead system and provides entry guidance for running equipment on or into the wellhead assembly.

Pressure Containing Parts — Those parts whose failure to function as intended would result in a release of retained fluid to the atmosphere. Examples are bodies, bonnets, and stems.

Pressure Controlling Parts — Those parts intended to control or regulate the movement of pressurized fluids, such as valve bore sealing mechanisms and hangers.

Riser Tieback — Tubular members that extend wellbores and annulii from the seafloor to the surface.

Running Tool — A tool used to run, retrieve, position, or connect subsea equipment remotely from the surface. Examples are tree running tools, tree cap running tools, flowline connector running tools, etc.

Second End Connection — The connection made at the termination of the pipelaying process.

Subsea BOP — Blow-out preventer stack designed for use on subsea wellheads. Provides the capability to remotely shear and seal the wellhead bore. Also provides the capability to circulate from the surface through the wellhead.

Subsea Casing Hangers — A device that supports a casing string in the wellhead at the mudline.

Subsea Completion Equipment — Specialized tree and wellhead equipment used to complete a well below the surface of a body of water. May be made above a subsea wellhead or mudline suspension system. Equipment includes subsea wellhead, tree, tree appurtenances (e.g., tree cap, control pod), and associated subsea tree running tools.

Subsea Wellhead Housing — A pressure containing housing that provides a means for suspending and sealing the well casing strings installed during a floating drilling operation.

Subsea Wireline/Coiled Tubing BOP — A subsea BOP that attaches to the top of a subsea tree to facilitate wireline or coiled tubing intervention.

Swivel Flange (Type 17SV) — A flange assembly consisting of a central hub and a loose flange rim which is free to rotate about the hub. The rotating flange rim has holes to accept bolts. The central hub has a sealing mechanism which will engage an API ring gasket. API type SV swivel flanges will mate with standard API type 17SS and 6BX flanges of the same size and pressure rating.

Temporary Guidebase — A structural device that provides a guide template for drilling the conductor hole and stabbing the conductor pipe.

Through Flowline (TFL) Tools — Tools designed to be transported and operated hydraulically, using a TFL system. The tools are pumped through the flowlines into the vertical bores of a subsea tree in order to perform routine service operations. Typical operations are: installation and retrieval of plugs, safety valves, and gas lift valves.

Tieback Adapter — A device used to provide the interface between mudline suspension equipment and subsea completion equipment.

Tool String Diverter — A device used to direct TFL tools at a branch connection.

Tree Cap — A protective cover for the upper tree connection. May be used to contain pressure, and as an integral part in the tree control system.

Tree Connector — A mechanism to join and seal a subsea tree to a subsea wellhead. May require diver assistance for installation, or be hydraulically actuated to permit remote operation.

Tree Guide Frame — Structural framework to provide guidance for installation of the subsea tree on the subsea wellhead. Also provides support for tree flowlines and connection equipment, control pods, anodes, and counterbalance weights.

Tree Mandrel — A tree upper connection profile, which allows remote connection of a tree running tool or tree cap.

Tree Upper Connection — The uppermost fitting of a subsea tree which allows full bore access to the tree. Connection profile may be API or other proprietary types (see tree mandrel).

Tubing Hanger Spool or Tubing Head Spool — A device to allow suspension of a tubing hanger above a subsea wellhead.

Tree Side Outlet — The outlet point at the surface of the tree block.

Umbilicals — Hose, tubing, piping, and/or electrical conductors which direct fluids and/or electrical current to or from subsea trees. Umbilical lines are typically used for control, monitoring, and/or injection functions.

Unpressurized Primary Structural Parts — Unpressurized primary structural parts are components that carry significant structural loads, but do not retain wellbore fluid.

Upstream — Direction of movement to the reservoir.

Valve Block — An integral block containing two or more valves.

Wave Zone — The zone where water particle velocities are derived from wave action.

Wear Bushings — A bore protector which also protects the casing hanger below it.

Wellhead Housing Pressure Boundary — The wellhead housing from the top of the wellhead to where the lowermost seal assembly seals.

Workover Riser — Equipment to provide a conduit from the tree upper connection to the surface and allows the passage of wireline tools. It must resist environmental wind, wave, and current forces (see completion riser).

Wye Spool — Spool between the master and swab (crown) valves of a TFL tree, that allows the passage of TFL tools from the flowlines into the bores of the tree.

SECTION 300
DESIGN AND PERFORMANCE — GENERAL REQUIREMENTS

301 PERFORMANCE REQUIREMENTS.

301.1 GENERAL. Performance requirements are specific and unique to the product in the as-shipped condition. All products shall be designed to perform in accordance with Sections 300, 900, 1000, and 1100 of API Specification 17D.

301.2 PRESSURE INTEGRITY. Product designs should be capable of withstanding rated working pressure at rated temperature without deformation to the extent that any other performance requirement is not met.

301.3 THERMAL INTEGRITY. Product designs should be capable of functioning throughout the temperature range for which the product is rated.

301.4 MATERIALS. Product designs should be capable of functioning consistent with the materials class in Table 302.3 of API Specification 6A.

301.5 LEAKAGE. No observable leakage is allowed.

301.6 LOAD CAPABILITY. Product designs should be capable of sustaining rated loads without deformation to the extent that any other performance requirement is not met. Product designs that support tubulars should be capable of supporting the rated load without collapsing the tubulars below the drift diameter.

301.7 CYCLES. Product designs should be capable of performing and operating as intended for the number of operating cycles specified by the manufacturer.

301.8 OPERATING FORCE OR TORQUE. Products should be designed to operate within the manufacturer's force or torque specification, as applicable.

302 SERVICE CONDITIONS.

302.1 PRESSURE RATINGS.

302.1a General. Pressure ratings for API 17D equipment shall comply with Section 302.1c of API Specification 6A. In addition, the effects of external loads (i.e. bending moments, tension), ambient hydrostatic loads and fatigue shall be considered.

302.1b Subsea Trees. Pressure controlling and containing parts that comprise the subsea tree assembly shall be designed to operate in only the following standard maximum rated working pressures: 5,000, 10,000, or 15,000 psi (34,5; 69,0; and 103,5 MPa).

302.1c Tubing Hangers. Tubing hangers and associated seals which could retain SCSSV control fluid pressure in the event of a control fluid leak may also be designed in 7,500 and 12,500 psi (49,5 and 86,3 MPa) rated working pressures in addition to the standard pressures given in Section 302.1b.

302.1d Subsea Wellhead Equipment. The standard maximum rated working pressures for subsea wellheads shall be 2,000, 5,000, 10,000, or 15,000 (13,8; 34,5; 69,0; and 103,5 MPa). Tools and internal components such as casing hangers may have other pressure ratings, depending on size.

302.1e Mudline Equipment. Standard rated working pressures do not apply to mudline equipment; instead, each equipment piece shall be rated for working pressure per methods given in Section 1100 of this specification.

302.1f Hydraulic Control Components. Hydraulic control components other than for SCSSV circuits shall have standard maximum rated working pressures of 1,500 or 3,000 psi (10,3 or 20,7 MPa). Hydraulic control circuits for SCSSVs shall have standard maximum rated working pressures equivalent to the tubing hanger given in Section 302.1c.

302.1g Other Equipment. The design of other equipment such as running, retrieval, and test tools shall comply with manufacturer's written specifications.

302.2 TEMPERATURE RATINGS.

302.2a Standard Operating Temperature Rating. Subsea equipment covered by this specification shall be designed and rated to operate throughout a temperature range of 35°F to 250°F (2°C to 120°C).

302.2b Standard Operating Temperature Rating Adjusted for Seawater Cooling. If the manufacturer shows through analysis or testing that certain equipment on subsea wellhead, mudline suspension, and tree assemblies, such as valve and choke actuators, will not exceed 150°F when operated subsea with a retained fluid at 250°F, then this equipment may be designed and rated to operate throughout a temperature range of 35°F to 150°F (2°C to 65°C).

302.2c Nonstandard Operating Temperature Rating. If manufacturer's subsea equipment is to be rated to temperatures below 35°F (2°C) or greater than 250°F (120°C), then the subsea equipment shall be tested at rated working pressure or greater per Section 307 of this specification at the new temperatures, and the new temperature range shall be clearly marked on the equipment per Section 704 of this specification. Adjustments in temperature rating per Section 302.2b of this specification shall be clearly marked.

302.2d Storage/Test Temperature Considerations. If subsea equipment is to be stored or tested on the surface at temperatures outside of its temperature rating, then the manufacturer should be contacted to determine if special storage or surface testing procedures are recommended. Manufacturers shall document any such special storage or surface testing considerations.

302.3 MATERIALS CLASS RATINGS.

302.3a General. Shall comply with Section 302.3a of API Specification 6A.

302.3b Materials Classes. Choosing materials classes is the ultimate responsibility of the user. Refer to Appendix A.4 of this specification for recommendations (not requirements) for materials class selection. Material requirements shall comply with Table 302.3 of API Specification 6A. All pressure containing components of API Specification 17D Equipment shall be treated as "Bodies" for determining material requirements from Table 302.3 of API Specification 6A. However, in this specification, other wellbore pressure boundary penetration equipment, such as grease/bleeder fittings and lockdown screws, shall be treated as "stems" as set forth in API Specification 6A, Table 302.3. Metal seals shall be treated as pressure controlling parts in Table 302.3 of API Specification 6A.

302.4 EXTERNAL HYDROSTATIC PRESSURE. In subsea applications, external hydrostatic pressure may be higher than internal system pressure. This external loading situation shall be considered in the design of API Specification 17D equipment.

303 DESIGN METHODS.

NOTE: *Fatigue consideration shall be evaluated where applicable in Sections 900, 1000, and 1100 of this specification. ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, Appendix 5, methodology may be used when calculating fatigue. Localized bearing stress values are beyond the scope of this specification.*

303.1 STANDARD API FLANGES, HUBS, AND THREADED EQUIPMENT. Flanges and hubs for subsea use shall be designed in accordance with Sections 901, 902, and/or 903 of this specification.

303.2 PRESSURE CONTROLLING COMPONENTS. Casing hangers, tubing hangers, and all pressure controlling 17D components, except for mudline suspension wellhead equipment, shall be designed in accordance with Section 303.2 of API Specification 6A.

Pressure controlling components of mudline equipment shall be designed in accordance with Section 1100 of this specification.

303.3 PRESSURE CONTAINING COMPONENTS. Wellheads, bodies, bonnets and other pressure containing 17D components shall be designed in accordance with Section 303.3 of API Specification 6A.

For purpose of design, lock screws and stems shall comply with Section 303.2 of API Specification 6A.

303.4 CLOSURE BOLTING. Closure bolting shall be designed in accordance with Section 303.4 of API Specification 6A. Refer to Appendix F of this specification for recommended bolt makeup torque.

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

Closure bolting manufactured from carbon or alloy steel shall not be used in submerged service at hardness levels exceeding Rockwell "C" 35.

303.5 UNPRESSURIZED PRIMARY STRUCTURAL COMPONENTS. Unpressurized primary structural components such as guide bases shall be designed in accordance with accepted industry practices and documented in accordance with API Specification 6A, Section 305. A safety factor of 1.5 or more shall be used in the design calculations.

As an alternative, a design verification load test of 1.5 times its rated capacity may be substituted for design analysis. The component must sustain the test loading without deformation to the extent that any other performance requirement is not met, and the test documents shall be retained.

303.6 SPECIFIC EQUIPMENT. Refer to Section 303.6 of API Specification 6A. In addition, refer to Sections 900, 1000 and 1100 of this specification for additional design requirements. If specific design requirements in Sections 900, 1000, and 1100 of this specification differ from the general requirements in Section 300 of this specification, then the equipment's specific design requirements shall take precedence.

303.7 DESIGN OF LIFTING DEVICES.

303.7a Padeyes. Padeyes shall be designed in accordance with documented industry practice using a design factor of safety of 4 or greater based on minimum specified ultimate material strength at the maximum rated pickup angle. Load capacities of padeyes shall be marked as per Section 700 of this specification.

303.7b Other Lifting Devices. Other lifting devices such as running tools shall be designed per Section 303.5 of this specification. If the lifting devices are either pressure containing or controlling, and are designed to be pressurized during lifting operations, then the load capacity shall include stresses induced by internal rated working pressure. Load capacity shall be marked on all lifting devices per Section 700 of this specification.

Running tools for subsea wellhead equipment are beyond the scope of this document. Refer to Appendix G of this specification for recommended guidelines for design of these tools.

Specific requirements for design of mudline equipment running tools are given in Section 1100 of this specification.

303.7c Performance Verification Testing. Performance Verification Testing of lifting devices shall be done in accordance with Section 307.5 of this specification.

304 MISCELLANEOUS DESIGN INFORMATION.

304.1 GENERAL. Shall comply with Section 304.1 of API Specification 6A.

304.2 FRACTION TO DECIMAL EQUIVALENCE. Table 304.1 in API Specification 6A gives the equivalent fraction and decimal values.

304.3 TOLERANCES. Unless otherwise specified in tables or figures of this specification, the following tolerances shall apply:

Dimension	Tolerance
X.XX	±0.02
X.XXX	±0.005

304.4 BOLTING. Shall comply with Sections 303.4 and 304.4 of API Specification 6A.

304.5 TEST, VENT, INJECTION, AND GAGE CONNECTIONS. Shall comply with Section 904 of this specification, or Section 304.5 of API Specification 6A.

304.6 EXTERNAL CORROSION CONTROL PROGRAM. External corrosion control for subsea trees and wellheads should be provided by appropriate materials selection, coating systems, and cathodic protection. A corrosion control program is an ongoing activity which consists of testing, monitoring, and replacement of spent equipment. The implementation of a corrosion control program is beyond the scope of this document.

304.7 COATINGS (EXTERNAL).

304.7a The coating system and procedure used shall comply with the written specification of the equipment manufacturer, the coating manufacturer, or Appendix D of this specification.

304.7b The manufacturer shall maintain, and have available for review, documentation describing the coating systems and procedures used.

304.7c Underwater visibility should be considered when selecting coating colors.

304.8 CATHODIC PROTECTION. Cathodic protection system design requires the consideration of the external area of the equipment to be protected. It is the responsibility of the equipment manufacturer to document and maintain the information on the wetted area of all equipment supplied according to Section 305 of this specification. This documentation shall contain the following information as a minimum:

- Location and size of wetted surface area for specific materials.
- Areas where welding is prohibited.
- Materials of construction and coating systems applied to external wetted surfaces.
- Control line interface locations.
- Flowline interfaces.

Cathodic protection design guidelines are contained in the following:

- "Corrosion Control on Steel, Fixed Offshore Platforms Associated with Petroleum Production," NACE Standard RP-01-76, NACE, Houston, Texas.
- "Cathodic Protection Design," Veritas Offshore Standard RP B401, Det Norske Veritas, Hovik, Norway.

NOTE: *Some materials have demonstrated a susceptibility to hydrogen embrittlement when exposed to cathodic protection in seawater. Care should be exercised in the selection of materials for applications requiring high strength, corrosion resistance, and resistance to hydrogen embrittlement. Materials which have shown this susceptibility include martensitic stainless steels and more highly alloyed steels having yield strengths over 150,000 psi (1035,0 MPa). Other materials subject to this phenomenon are hardened low alloy steels, particularly with hardness levels of Rockwell "C" 35 or greater, precipitation hardened nickel-copper alloys, and some high strength titanium alloys.*

305 DESIGN DOCUMENTATION. Design documentation shall be in accordance with Section 305 of API Specification 6A.

306 DESIGN REVIEW. Shall be in accordance with Section 306 of API Specification 6A.

307 PERFORMANCE VERIFICATION TESTING.

307.1 SCOPE. This section defines the performance verification test procedures to be used to qualify product designs.

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

307.3 HYDROSTATIC AND GAS TESTING. Hydrostatic pressure tests shall be acceptable for all performance verification pressure tests for API 17D equipment. Manufacturers may at their option substitute gas test for some or all of the required performance verification pressure test. Hydrostatic and gas performance verification test procedures and acceptance criteria shall meet the requirements set forth in Section 600 of this specification.

307.4 HYDROSTATIC PRESSURE CYCLING TESTS. Table 307.1 lists API Specification 17D equipment which must be subjected to repetitive hydrostatic pressure cycling tests to simulate startup and shutdown pressure cycling which will occur in long term field service. For these hydrostatic cycling tests, the equipment shall be alternately pressurized to the full rated working pressure and then depressurized until the specified number of pressure cycles have been completed. No holding period is required for each pressure cycle. A standard hydrostatic (or gas if applicable) test (ref. Section 600 of this specification) shall be performed before and after the hydrostatic pressure cycling test.

307.5 LOAD TESTING. The manufacturer's rated load capacities for API Specification 17D equipment shall be verified by either performance verification testing, Finite Element Analysis (FEA) or classical engineering analysis. If testing is used to verify the design, the equipment shall be loaded to the rated capacity at least three times during the test without deformation to the extent that any other performance requirement is not met. If FEA or engineering analysis is used, the analysis shall be conducted using techniques and programs which comply with documented industry practice.

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

307.7 TEMPERATURE CYCLING. Table 307.1 lists API Specification 17D equipment which shall be subjected to repetitive temperature cycling tests to simulate startup and shutdown temperature cycling which will occur in long term field service. For these temperature cycling tests, the equipment shall be alternately heated and cooled to the upper and lower temperature extremes of its rated operating temperature classification as defined in Section 307.6 above. During temperature cycling, rated working pressure shall be applied to the equipment at the temperature extremes with no leaks. Temperature cycling from room temperature to the lower temperature extreme plus cycling from room temperature to the upper temperature extreme may be substituted for temperature cycling directly between the two temperature extremes. As an alternative to testing, the manufacturer shall provide other objective evidence, consistent with documented industry practice, that the equipment will meet performance requirements for temperature cyclings.

307.8 LIFE CYCLE/ENDURANCE TESTING. Life cycle/endurance testing, such as make-break tests on connectors and operational testing of valves, chokes, and actuators, is intended to evaluate long-term wear characteristics of the equipment tested. Such tests may be conducted at any temperature. Table 307.1 lists API Specification 17D equipment which shall be subjected to extended life cycle/endurance testing to simulate long-term field service. For these life cycle/endurance tests, the equipment shall be subjected to operational cycles per manufacturer's performance specifications (i.e., make up to full torque/ break out, open/close under full rated working pressure). Additional specifications for life cycle/endurance testing of the components listed in Table 307.1 may be found in the equipment specific sections of this specification covering these items (Sections 900, 1000, and 1100).

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

(a) Nominal sizes for Valves, Connectors, Hangers* and Packoffs* are defined as follows:

1 13/16, 2 1/16, 2 9/16, 3 1/16 or 3 1/8, 4 1/16 or 4 1/8, 5 1/16 or 5 1/8, 7 1/16, 9, 11, 13 5/8, 16 3/4, 18 3/4, 20 3/4 or 21 1/4, and 26 3/4 inches (46, 52, 65, 78, 103, 130, 179, 228, 279, 346, 425, 476, 527 or 540, and 680 mm).

(b) Nominal sizes for Pipes, Hangers* and Packoffs* are defined as follows:

2 1/16, 2 3/8, 2 7/8, 3 1/2, 4, 4 1/2, 5, 5 1/2, 6 5/8, 7, 7 5/8, 8 5/8, 9 5/8, 10 3/4, 11 3/4, 13 3/8, 16, 18 5/8 and 20 inches (52, 60, 73, 89, 102, 114, 127, 140, 168, 179, 194, 219, 244, 273, 298, 340, 406, 473, and 508 mm).

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

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

307.10 DOCUMENTATION. The manufacturer shall document the procedures used and the results of all performance verification tests used to qualify equipment to API Specification 17D. The documentation requirements for performance verification testing shall be the same as the documentation requirements for design documentation in Section 305 of this specification. In addition, documentation shall identify the person(s) conducting and witnessing the tests, and the time and place of the testing.

TABLE 307.1
ADDITIONAL PERFORMANCE VERIFICATION TEST REQUIREMENTS

COMPONENT	PRESSURE CYCLING TEST	TEMPERATURE CYCLING TEST	ENDURANCE CYCLING TEST
Other End Connectors	200	NA	PMR* or 3*** minimum
Wellhead/Tree/Spool Connectors	3	NA	PMR or 3*** minimum
Tubing Hanger Spools	3	NA	NA
Valves	200	3	200
Valve Actuators	200	3	200
Tree Cap Connectors	3	NA	PMR or 3*** minimum
Flowline Connectors	200	NA	PMR or 3*** minimum
Subsea Chokes	200	NA	200
Subsea Choke Actuators	200	3	200
Subsea WH Casing Hangers	3	NA	NA
Subsea WH Annulus Seal Assemblies	3	3	NA
Subsea WH Tubing Hangers	3	3	3***
Mudline WH Tubing Hanger Spools	3	NA	NA
Mudline WH Tubing Hangers	3	3	3***
Running Tools**	3	NA	PMR or 3*** minimum

* Per Manufacturer's Rating
** Subsea Wellhead Running Tools are not included (refer to Section 1001.10)
*** Seals and other consumable items may be replaced between cycles.

SECTION 400
MATERIALS — GENERAL REQUIRMENTS

401 GENERAL. The material performance, processing and compositional requirements for all pressure containing and pressure controlling parts specified in Sections 900, 1000, and 1100 shall conform to API Specification 6A, Section 400. For purposes of this reference, subsea wellheads and tubing hanger spools shall be considered as bodies.

402 MATERIAL PROPERTIES. In addition to the materials specified in API Specification 6A, Section 400, other higher strength materials may be used provided they satisfy the design requirements of Section 300 and comply with the manufacturer's written specifications.

403 PRODUCT SPECIFICATION LEVEL. The materials used in equipment covered by this specification shall comply with requirements for PSL 2 or PSL 3 as established in API Specification 6A. In addition, all materials for API Specification 17D PSL 3 equipment shall be subjected to Charpy V-notch impact testing per procedures set forth in API Specification 6A. All PSL 3 materials, regardless of temperature rating, shall meet minimum average impacts of 15 foot-lbs. (20,3 J) in the transverse direction at 0°F (-18°C) for all similar 17D PSL 3 equipment.

404 CORROSION CONSIDERATIONS.

404.1 CORROSION FROM RETAINED FLUIDS. Material selection based upon wellbore fluids shall be made according to Section 302.3.

404.2 CORROSION FROM MARINE ENVIRONMENT. Corrosion protection through material selection based upon a marine environment should consider, as a minimum, the following:

— external fluids
— internal fluids
— weldability
— crevice corrosion
— dissimilar metals effects
— cathodic protection effects
— coatings

404.3 CORROSION RESISTANT INLAYS. Corrosion resistant inlays or overlays shall be made in accordance with Section 503 of this specification.

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

SECTION 500
WELDING — GENERAL REQUIREMENTS

501 PRESSURE CONTAINING/CONTROLLING COMPONENTS. All welding on pressure containing/controlling components shall comply with the requirements of API Specification 6A, Section 500 for PSL 2 and PSL 3, as specified.

502 STRUCTURAL COMPONENTS. Structural welds shall be treated as nonpressure containing welds and comply with API Specification 6A, Section 502 or a documented structural welding code such as AWS D1.1.

503 CORROSION RESISTANT INLAYS OR OVERLAYS. Corrosion resistant inlays or overlays shall be made in accordance with Section 505 of API Specification 6A.

SECTION 600
QUALITY CONTROL — GENERAL REQUIREMENTS

601 GENERAL. The quality control requirements for equipment specified in Sections 900, 1000, and 1100 shall conform to Sections 300, 400, 500, and 600 of this specification and Section 600 of API Specification 6A.

For those 17D components not covered in Section 600 of API Specification 6A, equipment specific quality control requirements shall comply with the manufacturer's written specifications.

602 PRODUCT SPECIFICATION LEVEL. Quality control and testing covered by this specification shall comply with requirements for PSL 2 and PSL 3 as established in API Specification 6A.

603 STRUCTURAL COMPONENTS. Quality control and testing of welding for structural components shall be as specified for "nonpressure containing" welds as established in API Specification 6A, Table 605.2.

604 LIFTING DEVICES. Welds on padeyes and other lifting devices attached by welding shall be subjected to either magnetic particle or dye penetrant testing as specified in API Specification 6A, Section 605.2b(12).

605 HYDROSTATIC AND GAS TESTING. Procedures for hydrostatic pressure testing of equipment specified in Sections 900, 1000, and 1100 of this specification shall conform to the requirements for PSL 2 or PSL 3 as described in API Specification 6A, with the exception that parts may be painted prior to testing.

For equipment with a rated working pressure of 5000 psi (34,5 MPa) or below, the hydrostatic body test pressure shall be two times the rated working pressure.

For equipment with a rated working pressure greater than 5000 psi (34,5 MPa), the hydrostatic body test pressure shall be one and one-half times the rated working pressure.

Maximum test pressures for mudline equipment specified in Section 1100 of this specification shall conform to the requirements described in Appendix E of this specification.

Gas testing is not required by this specification. However, if specified by the manufacturer, gas tests shall be performed in accordance with API Specification 6A, Section 605.9f, or the manufacturer's written specification.

606 OTHER PRESSURE BOUNDARY PENETRATIONS. In this specification, other pressure boundary penetration equipment such as grease/bleeder fittings, which penetrate directly into or communicate with the wellbore, shall be treated as "stems" per API Specification 6A, Section 600.

SECTION 700
EQUIPMENT MARKING — GENERAL REQUIREMENTS

701 GENERAL. Equipment marked "17D" shall meet the requirements of this specification.

Equipment shall be marked in accordance with Section 700 of API Specification 6A, except that the marking "17D" shall replace the marking "6A." For equipment which meets all the requirements of both API Specifications 6A and 17D, both markings "6A" and "17D" may be applied. Similarly, for equipment which meets all the requirements of both API Specifications 14D and 17D, both the markings "14D" and "17D" may be applied. All equipment marked "17D" shall, also, be marked with the following minimum information: part number, manufacturer name or trademark. Refer to Table 701.1 in API Specification 6A for metallic marking locations. In addition, API 17D Specification subsea tree assemblies which meet all of the requirements in Section 922 of this specification may also be marked as "17D" tree assemblies.

Equipment shall be marked in either English units or Metric units as per Section 105 of this specification. If metric units are used, then the units shall also be marked along with the numbers.

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

Example: Four padeyes, 25 tons (23 tonnes) capacity each, no angle limitation, total capacity of 100 tons (91 tonnes).

Stamp: 4 x
SWL 25 tons (or 23 tonnes)
0 - 90°

703 OTHER LIFTING DEVICES. The rated lifting capacity of other lifting devices such as tools, as determined in Section 303.7 of this specification, shall be clearly marked in a position visible when the lifting device is in the operating position. In addition, this equipment shall be marked with rated working pressure, manufacturer's name or trademark and model or part number.

704 TEMPERATURE RATINGS. Subsea equipment manufactured in accordance to Section 302.2a of this specification shall be stamped "35 - 250°F" ("2 - 120°C").

Subsea equipment manufactured in accordance to Section 302.2b of this specification shall be stamped "35 - 150 (250)°F" ("2 - 65 (120)°C") where the "(250)" "(120)" refers to the maximum retained fluid temperature.

Subsea equipment manufactured in accordance with Section 302.3c of this specification shall be stamped as follows:

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

Stamp: 35 - 350°F or (2 - 175°C)

SECTION 800
STORING AND SHIPPING

801 DRAINING AFTER TESTING. All equipment shall be drained and lubricated per manufacturer's written specification after testing prior to storage or shipment.

802 RUST PREVENTION. Prior to shipment, parts and equipment shall have exposed metallic surfaces (except those specially designated such as anodes or nameplates) either protected with a rust preventive coating which will not become fluid at temperatures less than 125°F (50°C), or filled with a compatible fluid containing suitable corrosion inhibitors per manufacturer's written specification. Equipment already coated, but showing damage after testing, should undergo coating repair prior to storage or shipment per Section 304.7 of this specification.

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

804 LOOSE SEALS AND RING GASKETS. Loose seals, stab subs, and ring gaskets shall be individually boxed or wrapped for shipping and storage.

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

806 HYDRAULIC SYSTEMS. Prior to shipment, hydraulic line fluid shall be flushed and filled per manufacturer's written specification. Exposed hydraulic end fittings shall be capped or covered.

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

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

809 ASSEMBLY AND MAINTENANCE INSTRUCTIONS. The manufacturer shall document instructions concerning field assembly and maintenance of equipment.

SECTION 900
SUBSEA TREE AND RELATED EQUIPMENT — SPECIFIC REQUIREMENTS

Sections 901 through 921 of this specification provide specific requirements for equipment related to subsea trees. Section 922 of this specification provides specific requirements for the assembly of subsea trees. Refer to Appendix A of this specification for purchasing guidelines.

901 FLANGED END AND OUTLET CONNECTIONS.

901.1 GENERAL—FLANGE TYPES AND USES. This section controls the API type end and outlet flanges used on Specification 17D subsea completions equipment. Table 901.1 lists the types and sizes of API flanges covered by this Specification.

Standard flanges for subsea completion equipment with working pressures of 5000 psi (34,5 MPa) and below in nominal sizes of 2" (51 mm) through 11" (279 mm) shall be API Type 17SS flanges as defined in Section 901.2b of this specification. Type 17SS flanges are based on API Type 6B flanges, as defined in API Specification 6A, modified slightly to be consistent with established subsea practice. The primary modifications are substitution of BX type ring gaskets for subsea service and slight reductions of through bore diameters on some flange sizes. Type 17SS flanges have been developed for the nominal sizes and rated working pressures shown in Table 901.1.

Standard flanges for 5000 psi and below in nominal sizes of 13 5/8" (346 mm) through 21 1/4" (540 mm) shall be API Type 6BX flanges as defined in API Specification 6A, Section 901.

Standard flanges for subsea completions with maximum working pressures of 10,000 psi (69,0 MPa) or 15,000 psi (103,5 MPa) shall be API Type 6BX flanges as defined in API Specification 6A, Section 901.

API type flanges for subsea completions may be either integral, blind or weld neck flanges. Threaded flanges, as defined in API Specification 6A, Section 901, shall not be used on subsea completion equipment handling produced fluids except as noted in Section 903 of this specification.

Segmented flanges for subsea completions shall comply with the specifications for segmented flanges as defined in Section 901.2d of this specification.

Swivel flanges are often used to facilitate subsea flowline connections which are made up underwater. API Type 17SV flanges, as defined herein, have been developed as the "standard" swivel flange design for subsea completions in the sizes and working pressures shown in Table 901.1. Type 17SV swivel flanges are designed to mate with standard API Type 17SS and Type 6BX flanges of the same size and pressure rating.

All end and outlet flanges used on subsea completion equipment shall have their ring grooves either manufactured from or inlayed with corrosion resistant material in accordance with Section 901.2h of this specification.

901.2 DESIGN.

901.2a General. All flanges used on subsea completions equipment shall be of the ring joint type designed for face-to-face make-up. The connection make-up force and external loads react primarily on the raised face of the flange. Therefore, at least one of the flanges in a connection shall have a raised face.

All flanged connections which will be made up underwater per the manufacturer's written specification shall be equipped with means to vent any trapped fluids. Type SBX and SRX ring gaskets, as shown in Tables 906.1 and 906.2, are acceptable means for venting API flanges.

NOTE: *Other proprietary flange and seal designs have been developed which eliminate the trapped fluid problem and are therefore well suited for underwater makeup. These proprietary flange and seal designs shall comply with Section 904 of this specification.*

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

901.2b Standard Subsea Flanges — Working Pressures Up To 5000 Psi (34,5 MPa) (Type 17SS Flanges).

901.2b(1) General. 2" (52 mm) through 11" (279 mm) API Type 17SS flange designs are based on API Type 6B flange designs as defined in API Specification 6A, but they have been modified to incorporate Type BX ring gaskets (the established practice for subsea completions) rather than Type R or RX gaskets. In addition, Type 17SS flanges are designed with raised faces for rigid face-to-face make-up.

5000 psi (34,5 MPa) Type 17SS flanges shall be used for all 2" (52 mm) through 11" (279 mm) subsea completion API type flange applications at or below 5000 psi (34,5 MPa) working pressure.

13 5/8" (346 mm) through 21 1/4" (540 mm) standard subsea flanges for working pressures of 5000 psi and below shall be API Type 6BX flanges as defined in API Specification 6A, Section 901.

901.2b(2) Dimensions.

(a) Standard Dimensions.

Dimensions for Type 17SS integral flanges shall conform to Table 901.2 (Sheet 1 of 2).

Dimensions for Type 17SS weld neck flanges shall conform to Table 901.2 (Sheet 2 of 2).

Dimensions for Type 17SS blind flanges shall conform to Figure 901.1.

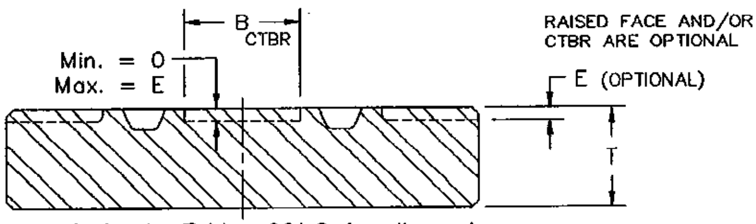
Dimensions for rough machining of BX ring grooves for corrosion-resistant inlays shall

TABLE 901.1
RATED WORKING PRESSURES AND SIZE RANGES OF API FLANGES

Rated Working Pressure psi (MPA)	Flange Size Range Type 17SS in.	(mm)	Type 17SV in.	(mm)	Type 6BX in.	(mm)	Segmented Dual in.	(mm)	Triple or Quadruple in.	(mm)
5,000 (34,5)	2 1/16 thru 11	(52 thru 279)	2 1/16 thru 11	(52 thru 279)	13 5/8 thru 21 1/4	(346 thru 540)	1 3/8 thru 4 1/16 x 4 1/4	(35 thru 103 x 108)	1 13/16 thru 4 1/16 x 4 1/4	(46 thru 103)
10,000 (69,0)	—	—	1 13/16 thru 11	(46 thru 279)	1 13/16 thru 21 1/4	(46 thru 540)	—	—	—	—
15,000 (103,5)	—	—	—	—	1 13/16 thru 18 3/4	(46 thru 496)	—	—	—	—

*Refer to API Specification 6A, Section 901.

FIGURE 901.1
TYPE 17SS BLIND FLANGES



Note Refer to Tables 901.2 for dimensions B and T and for dimensions not shown. For E dimensions refer to Table 906.1

FIGURE 901.2
WELD END PREPARATION FOR TYPE 17SS AND 17SV WELD NECK FLANGES

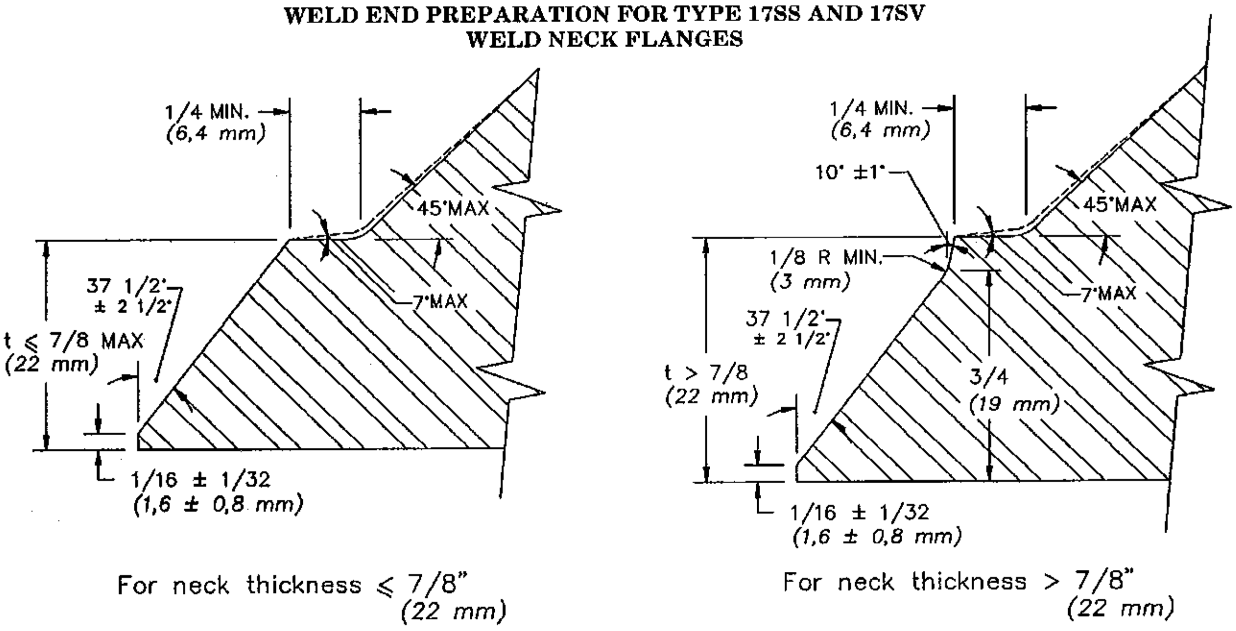
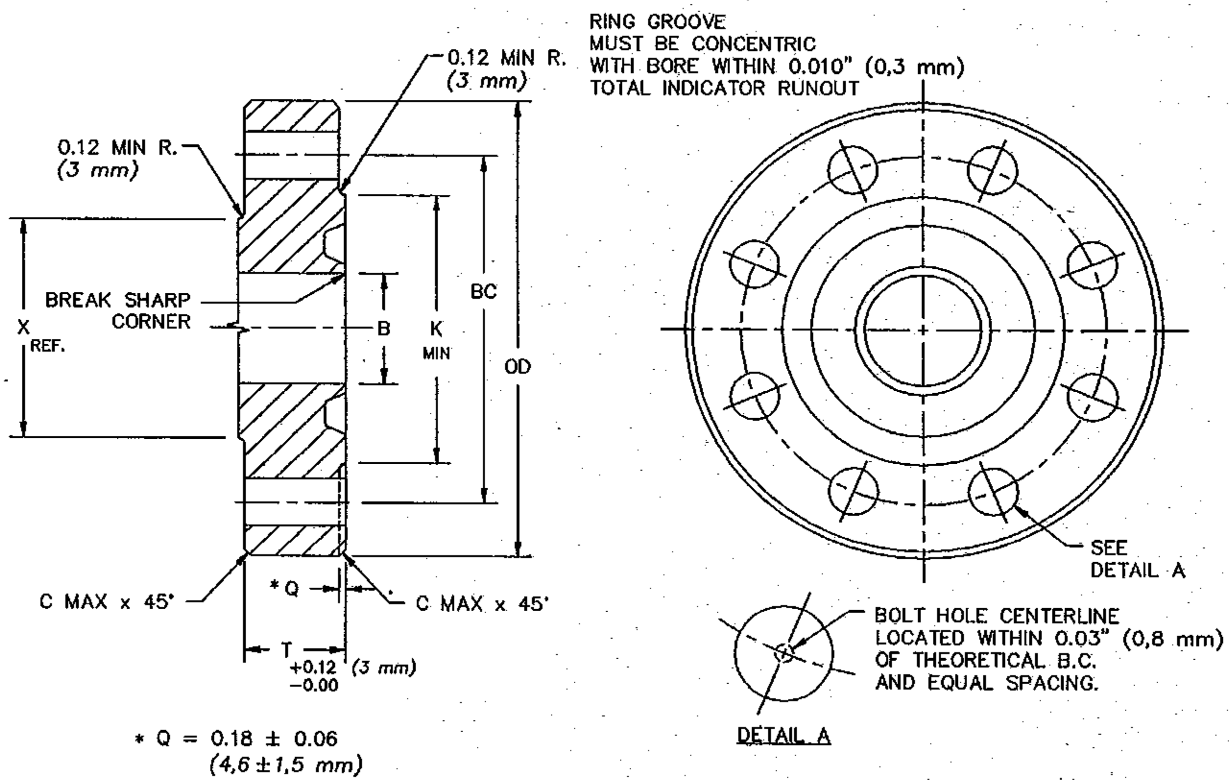


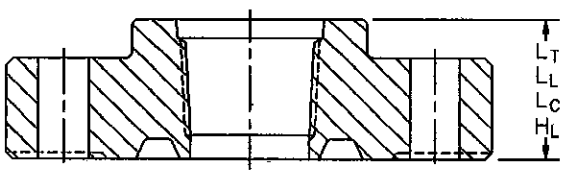
TABLE 901.2
Type 17SS Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure



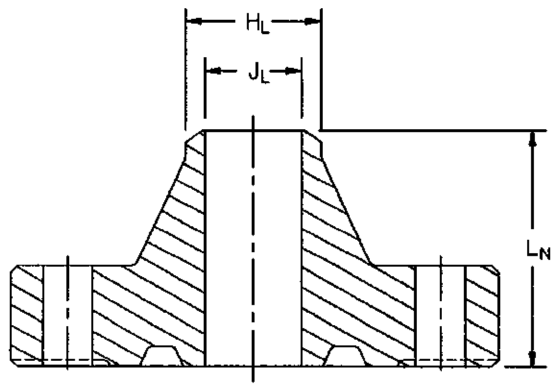
Basic Flange Dimensions								Bolting Dimensions						
Nominal Size and Bore of Flange	Max Bore B	Outside Diameter of Flange OD	Tolerance OD	Max Chamfer C	Diameter of Raised Face K	Total Thickness of Flange T	Diameter of Hub X	Diameter of Bolt Circle BC	Number of Bolts	Diameter of Bolts	Diameter of Bolt Holes	Bolt Hole Tolerance (see Note 1)	Length of Stud Bolts	BX Ring Number
in. (mm)	in. (mm)	in. (mm)	in. (mm)	in. (mm)	in. (mm)	in. (mm)	in. (mm)	in. (mm)		in. (mm)	in. (mm)	in. (mm)	in. (mm)	
2 1/16 (52)	2.09 (53,1)	8.50 (215)	±0.06 (±2)	0.12 (3)	5.03 (128)	1.81 (46,0)	4.12 (104,7)	6.50 (165,1)	8	7/8 (22)	1.00 (26)	+.06 (+2)	6.00 (155)	152
2 9/16 (65)	2.59 (65,8)	9.62 (245)	±0.06 (±2)	0,12 (3)	5.78 (147)	1.94 (49,3)	4.88 (124,0)	7.50 (190,5)	8	1 (25)	1.12 (29)	+.06 (+2)	6.50 (165)	153
3 1/8 (78)	3.09 (78,5)	10.50 (265)	±0.06 (±2)	0.12 (3)	6.31 (160)	2.19 (55,7)	5.25 (133,4)	8.00 (203,2)	8	1 1/8 (29)	1.25 (32)	+.06 (+2)	7.25 (185)	154
4 1/16 (103)	4.09 (103,9)	12.25 (310)	±0.06 (±2)	0.12 (3)	7,63 (194)	2.44 (62,0)	6.38 (162,1)	9.50 (241,3)	8	1 1/4 (32)	1.38 (36)	+.06 (+2)	8.00 (205)	155
5 1/8 (130)	5.16 (131,1)	14.75 (375)	±0.06 (±2)	0.12 (3)	9.38 (238)	3.19 (81,1)	7.75 (196,9)	11.50 (292,1)	8	1 1/2 (38)	1.62 (42)	+.06 (+2)	10.00 (255)	169
7 1/16 (179)	7.09 (180,1)	15.50 (395)	±0.12 (±3)	0.25 (6)	10,70 (272)	3.62 (92,0)	9.00 (228,6)	12.50 (317,5)	12	1 3/8 (35)	1.50 (39)	+.06 (+2)	10.75 (275)	156
9 (228)	9.03 (229,4)	19.00 (485)	±0.12 (±3)	0.25 (6)	13.25 (337)	4.06 (103,2)	11.50 (292,1)	15.50 (393,7)	12	1 5/8 (42)	1.75 (45)	+.09 (+2,5)	12.00 (305)	157
11 (279)	11.03 (280,2)	23.00 (585)	±0.12 (±3)	0.25 (6)	16.25 (418)	4.69 (119,2)	14.50 (368,3)	19.00 (482,6)	12	1 7/8 (48)	2.00 (51)	+.09 (+2,5)	13.75 (350)	158

NOTE 1: *Minimum bolt hole tolerance is −0,5 mm.*

TABLE 901.2 (continued)
Type 17SS Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure



THREADED FLANGE

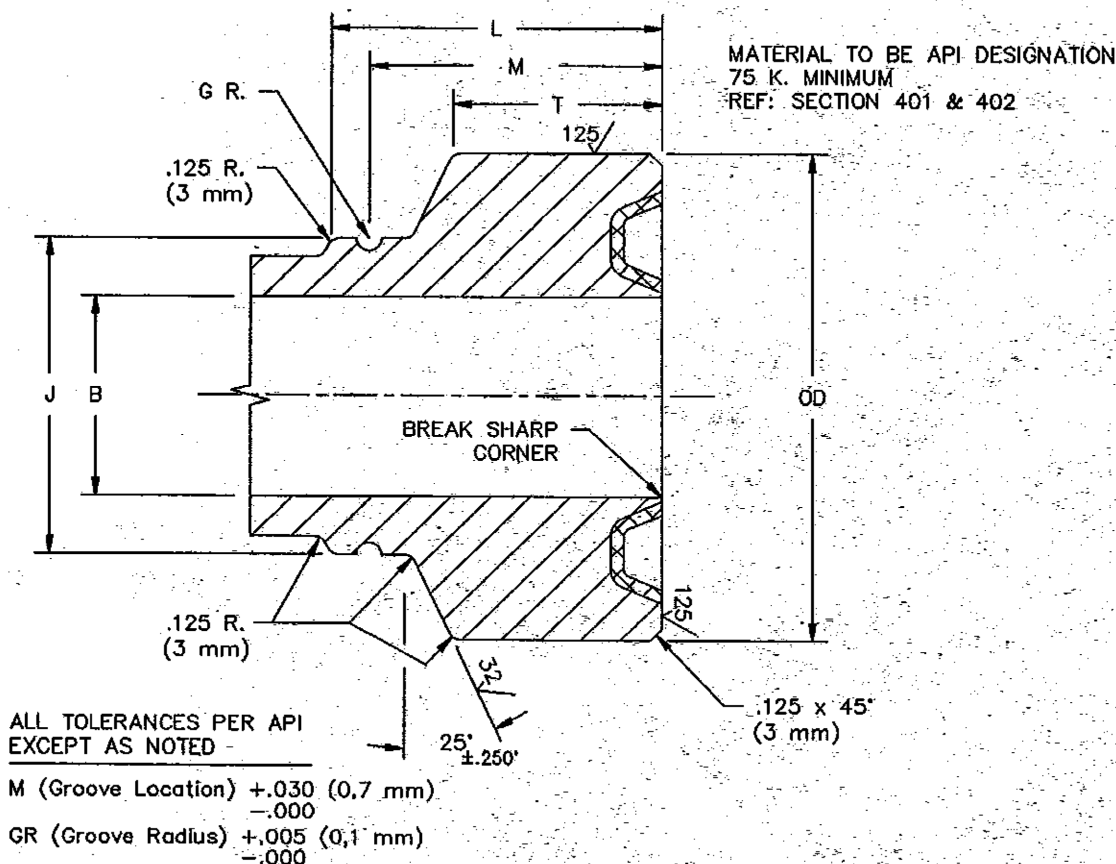


WELD NECK
LINE PIPE FLANGE

Hub and Bore Dimensions

Nominal Size and Bore of Flange in. (mm)	Hub Length Threaded Line-Pipe Flange L_L in. (mm)	Hub Length Threaded Casing Flange L_C in. (mm)	Hub Length Tubing Flange L_T in. (mm)	Hub Length Welding-Neck Line-Pipe Flange L_N±0.06(2) in. (mm)	Neck Diameter Welding-Neck Line-Pipe Flange H_L in. (mm)	Tolerance H_L in. (mm)	Maximum Bore of Welding Neck Flange J_L ±0.03 (0,7) in. (mm)
2 1/16 (52)	2.56 (65,1)	—	2.56 (65,1)	4.31 (109,5)	2.38 (60,5)	+0.09/−0.03 (+2/−0,7)	1.69 (43,0)
2 9/16 (65)	2.81 (71,4)	—	2.81 (71,4)	4.44 (112,8)	2.88 (73,2)	+0.09/−0.03 (+2/−0,7)	2.13 (54,1)
3 1/8 (98)	3.19 (81,1)	—	3.19 (81,1)	4.94 (125,5)	3.50 (88,9)	+0.09/−0.03 (+2/−0,7)	2.62 (66,5)
4 1/16 (103)	3.88 (98,6)	3.88 (98,6)	3.88 (98,6)	5.19 (131,9)	4.50 (114,3)	+0.09/−0.03 (+2/−0,7)	3.44 (87,4)
5 1/8 (130)	4.44 (112,8)	4.44 (112,8)	—	6.44 (163,6)	5.56 (141,2)	+0.09/−0.03 (+2/−0,7)	4.31 (109,5)
7 1/16 (179)	5.06 (128,6)	5.06 (128,6)	—	7.13 (181,1)	6.63 (168,4)	+0.16/−0.03 (+4/−0,7)	5.19 (131,0)
9 (228)	6.06 (154,0)	6.06 (154,0)	—	8.81 (228,8)	8.63 (219,2)	+0.16/−0.03 (+4/−0,7)	6.81 (173,0)
11 (279)	6.69 (170,0)	6.69 (170,0)	—	10.44 (265,2)	10.75 (273,1)	+0.16/−0.03 (+4/−0,7)	8.50 (215,9)

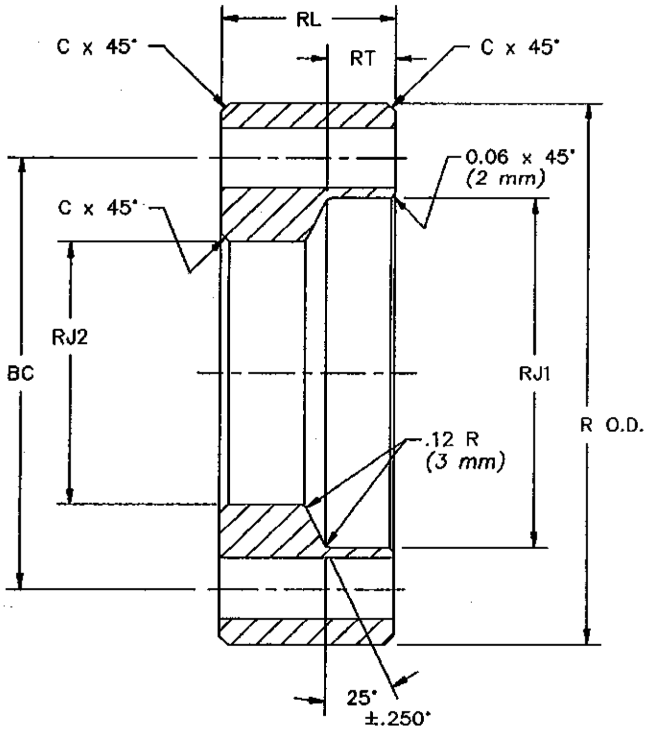
TABLE 901.3
Type 17SV Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure



Hub Dimensions

Nominal Size and Bore B in. (mm)	Outside Dia. OD in. (mm)	Total Thickness T in. (mm)	Large Dia. of Neck J in. (mm)	Length of Neck L in. (mm)	Groove Location M in. (mm)	Retainer Groove Radius GR in. (mm)	Ring Gasket No. BX
2¹/₁₆ (52)	5.031 (128)	1.166 (29,5)	3.555 (91)	3.282 (84)	2.907 (74)	.125 (3,2)	152
2⁹/₁₆ (65)	5.781 (147)	1.166 (29,5)	4.406 (112)	3.282 (84)	2.907 (74)	.125 (3,2)	153
3⅛ (78)	6.312 (160)	1.166 (29,5)	4.938 (126)	3.432 (88)	3.067 (78)	.125 (3,2)	154
4¹/₁₆ (108)	7.625 (194)	1.197 (30,5)	6.250 (159)	3.757 (96)	3.382 (86)	.125 (3,2)	155
5⅛ (130)	9.380 (240)	1.490 (36,0)	7.755 (197)	4.732 (121)	4.357 (111)	.125 (3,2)	169
7¹/₁₆ (179)	10.788 (275)	1.622 (41,5)	9.075 (281)	5.541 (141)	4.979 (127)	.188 (4,8)	156
9 (228)	13.250 (340)	1.622 (41,5)	11.625 (296)	6.113 (156)	5.551 (141)	.188 (4,8)	157
11 (279)	16.250 (415)	1.654 (42,0)	14.625 (372)	6.932 (162)	5.370 (162)	.188 (4,8)	158

TABLE 901.3 (continued)
Type 17SV Flanges for
5,000 psi (34,5 MPa) Rated Working Pressure

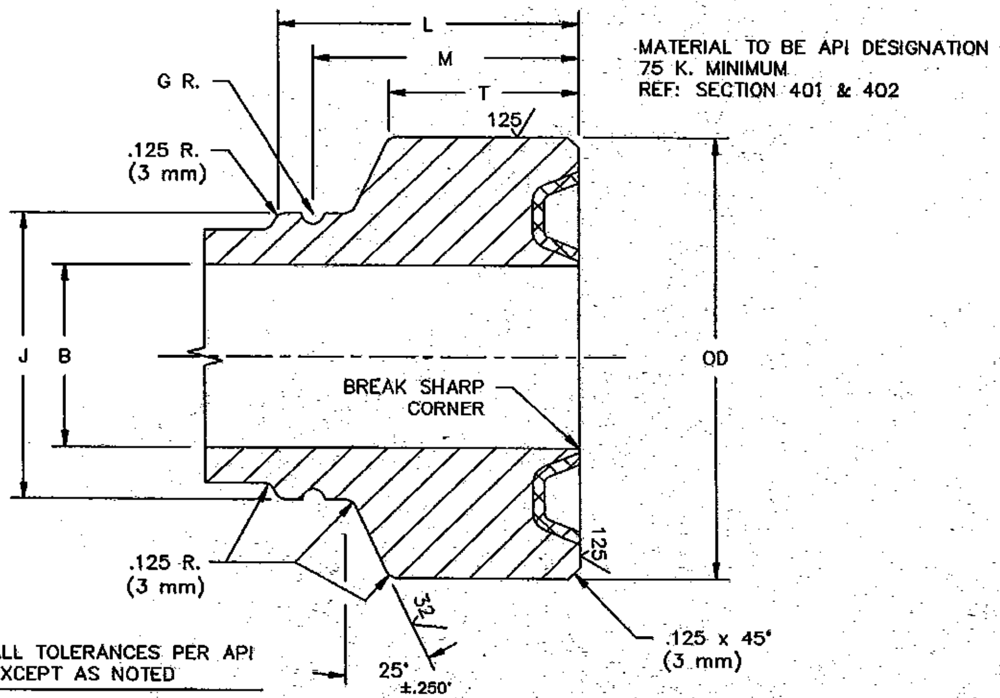


TOLERANCE:

R (Outside Dia.)		
Size 2 1/16 Thru 5 1/8	±.062	(2 mm)
Size 7 1/16 Thru 11	±.125	(3 mm)
RL (Length of Ring)	+.125 −.000	(3 mm)
RT (Depth of Large Dia.)	+.062 −.000	(2 mm)
RJ1 (Large I.D. Ring)	+.031 −.000	(1 mm)
RJ2 (Small I.D. Ring)	+.031 −.000	(1 mm)
C (Chamfer)	+.010 −.000	(0,3 mm)
Bolt Dia.		
Size 2 1/16 Thru 7 1/16	+.060 −.020	(2 mm) (0,5 mm)
Size 9 Thru 11	+.090 −.020	(2,5 mm) (0,5 mm)

	Basic Dimensions of Ring						Bolts		
Nominal Size and Bore of Hub in. (mm)	Outside Dia. of Ring R OD in. (mm)	Depth of LG ID RT in. (mm)	Large ID of Ring RJ1 in. (mm)	Small ID of Ring RJ2 in. (mm)	Length of Ring RL in. (mm)	Chamfer C in. (mm)	Dia. of Bolt Circle BC in. (mm)	Number of Bolts	Dia. of Bolt Holes in. (mm)
2¹⁄₁₆ (52)	8.50 (216)	.964 (24,5)	6.093 (129,4)	3.718 (94,5)	2.430 (63)	.125 (3)	6.50 (165,1)	8	1.00 (26)
2⁹⁄₁₆ (65)	9.62 (245)	.964 (24,5)	6.843 (148,5)	4.468 (113,5)	2.400 (63)	.125 (3)	7.50 (190,5)	8	1.12 (29)
3⅛ (78)	10.50 (267)	.964 (24,5)	6.375 (162,0)	5.000 (127,0)	2.500 (66)	.125 (3)	8.00 (203,2)	8	1.25 (32)
4¹⁄₁₆ (103)	12.25 (312)	.995 (25,3)	7.687 (195,3)	5.312 (160,4)	2.875 (49)	.125 (3)	9.50 (241,3)	8	1.38 (36)
5⅛ (130)	14.75 (375)	1.208 (30,7)	9.442 (239,9)	5.817 (198,6)	2.900 (99)	.125 (3)	11.50 (292,1)	8	1.62 (42)
7¹⁄₁₆ (179)	15.50 (394)	1.420 (36,1)	10.762 (273,4)	9.157 (232,1)	4.450 (114)	.188 (5)	12.50 (317,5)	12	1.50 (39)
9 (228)	19.00 (483)	1.420 (36,1)	13.210 (338,2)	10.557 (296,9)	5.311 (128)	.188 (5)	15.50 (393,7)	12	1.75 (45)
11 (279)	22.00 (585)	1.452 (36,9)	16.312 (414,4)	14.887 (373,1)	5.222 (149)	.188 (5)	19.00 (482,6)	12	2.00 (51)

TABLE 901.4
Type 17SV Flanges for
10,000 psi (69,0 MPa) Rated Working Pressure



ALL TOLERANCES PER API
EXCEPT AS NOTED

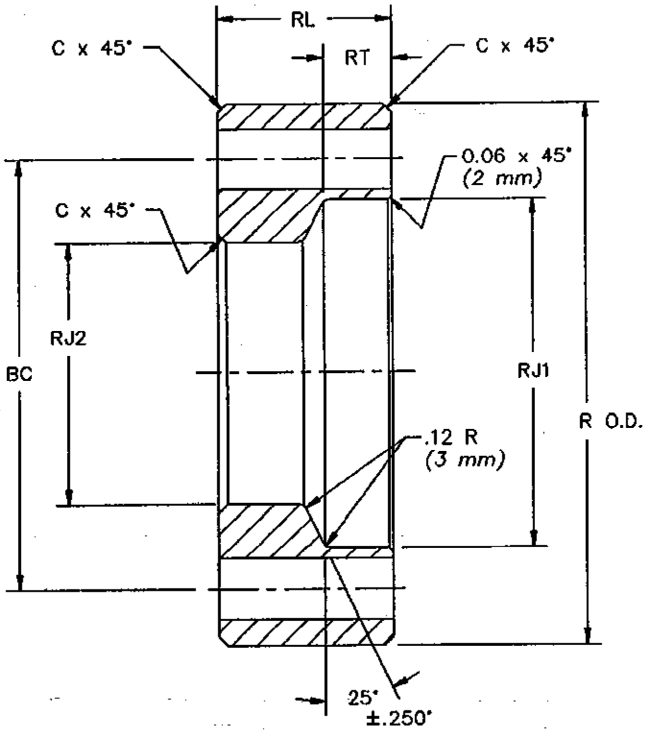
M (Groove Location) +.030 (0,7 mm)
−.000

GR (Groove Radius) +.005 (0,1 mm)
−.000

Hub Dimensions

Nominal Size and Bore in. (mm)	Outside Dia OD in. (mm)	Total Thickness T in. (mm)	Large Dia. of Neck J in. (mm)	Length of Neck L in. (mm)	Groove Location M in. (mm)	Retainer Groove Radius GR in. (mm)	Ring Gasket No. BX
1[13]/16 (46)	4.500 (115)	1.166 (29,5)	3.230 (82,6)	3.282 (84)	2.907 (74)	.125 (3,2)	151
2[1]/16 (52)	5.000 (130)	1.166 (29,5)	3.750 (95,3)	3.282 (84)	2.907 (74)	.125 (3,2)	152
2[9]/16 (65)	5.800 (150)	1.166 (29,5)	4.550 (115,6)	3.302 (84)	2.927 (75)	.125 (3,2)	153
3[1]/16 (78)	6.930 (175)	1.197 (30,5)	5.680 (144,3)	3.666 (94)	3.291 (84)	.125 (3,2)	154
4[1]/16 (103)	8.437 (215)	1.310 (33,3)	6.812 (173,0)	4.277 (109)	3.902 (99)	.125 (3,2)	155
5⅛ (130)	9.960 (255)	1.500 (38,1)	8.335 (211,7)	4.732 (121)	4.357 (111)	.125 (3,2)	169
7[1]/16 (179)	13.660 (350)	1.653 (42,0)	12.035 (305,7)	6.204 (158)	5.641 (143)	.188 (4,8)	156
9 (228)	16.250 (415)	1.653 (42,0)	14.625 (371,5)	7.270 (185)	6.707 (170)	.188 (4,8)	157
11 (279)	18.870 (480)	2.035 (51,7)	17.245 (438,0)	8.153 (207)	7.591 (193)	.188 (4,8)	158
13⅝ (346)	22.250 (565)	2.309 (58,7)	20.625 (523,9)	9.531 (242)	8.969 (228)	.188 (4,8)	159

TABLE 901.4 (continued)
Type 17SV Flanges for
10,000 psi (69,0 MPa) Rated Working Pressure



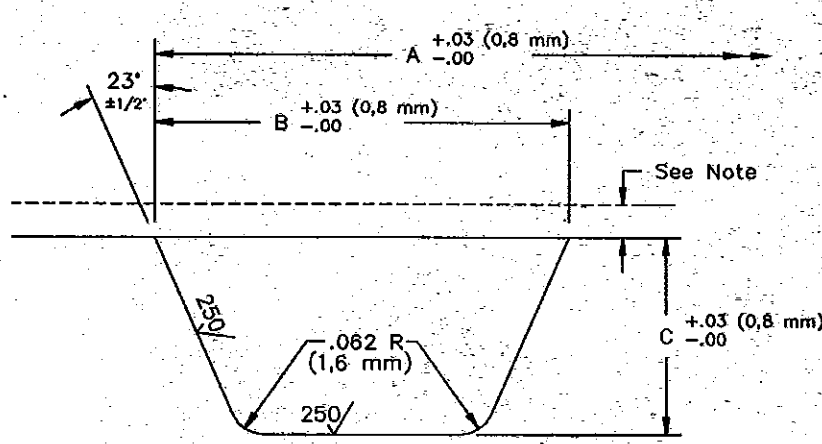
MATERIAL TO BE API DESIGNATION
75 K. MINIMUM
REF. SECTION 401 & 402

<u>TOLERANCE:</u>

R (Outside Dia.)		
Size 2 1/16 Thru 5 1/8	±.062	(2 mm)
Size 7 1/16 Thru 11	±.125	(3 mm)
RL (Length of Ring)	+.125 −.000	(3 mm)
RT (Depth of Large Dia.)	+.062 −.000	(2 mm)
RJ1 (Large I.D. Ring)	+.031 −.000	(1 mm)
RJ2 (Small I.D. Ring)	+.031 −.000	(1 mm)
C (Chamfer)	+.010 −.000	(0,3 mm)
Bolt Dia.		
Size 2 1/16 Thru 7 1/16	+.060 −.020	(2 mm) (0,5 mm)
Size 9 Thru 11	+.090 −.020	(2,5 mm) (0,5 mm)

Basic Dimensions of Ring								Bolts	
Nominal Size and Bore of Hub in. (mm)	Outside Dia. of Ring R OD in. (mm)	Depth of LG ID RT in. (mm)	Large I.D. of Ring RJ1 in. (mm)	Small ID of Ring RJ2 in. (mm)	Length of Ring RL in. (mm)	Chamfer C in. (mm)	Dia. of Bolt Circle BC in. (mm)	Number of Bolts	Dia. of Bolt Holes in. (mm)
1¹³⁄₁₆ (46)	7.38 (188)	.964 (24,5)	4.562 (115,9)	3.312 (84,1)	2.450 (63)	.125 (,3)	5.75 (146,1)	8	.88 (23)
2¹⁄₁₆ (52)	7.88 (200)	.964 (24,5)	5.062 (128,6)	3.812 (96,8)	2.450 (63)	.125 (,3)	6.25 (158,8)	8	.88 (23)
2⁹⁄₁₆ (65)	9.12 (232)	.964 (24,5)	5.862 (148,9)	4.612 (117,1)	2.470 (63)	.125 (,3)	7.25 (184,1)	8	1.00 (26)
3¹⁄₁₆ (78)	10.62 (270)	.995 (25,3)	6.992 (177,6)	5.742 (145,8)	2.834 (72)	.125 (,3)	8.50 (215,9)	8	1.12 (29)
4¹⁄₁₆ (103)	12.44 (316)	1.106 (28,1)	8.500 (215,9)	6.875 (174,6)	3.445 (88)	.125 (,3)	10.19 (258,8)	8	1.25 (32)
5⅛ (130)	14.05 (357)	1.299 (33,0)	10.022 (254,6)	8.397 (213,3)	3.900 (99)	.125 (,3)	11.81 (300,0)	12	1.25 (32)
7¹⁄₁₆ (179)	18.88 (480)	1.451 (36,9)	13.722 (348,5)	12.097 (307,3)	5.122 (130)	.188 (,5)	15.88 (403,4)	12	1.62 (42)
9 (228)	21.75 (552)	1.451 (36,9)	16.312 (409,7)	14.687 (373,0)	6.188 (158)	.188 (,5)	18.75 (496,3)	16	1.62 (42)
11 (279)	25.75 (654)	1.833 (46,6)	18.932 (480,9)	17.307 (439,6)	7.072 (180)	.188 (,5)	22.25 (565,2)	16	1.88 (48)
13⅝ (346)	30.25 (768)	2.107 (53,5)	22.312 (566,7)	20.587 (525,4)	8.450 (215)	1.88 (,5)	26.50 (673,1)	20	2.00 (51)

TABLE 901.5
ROUGH MACHINING DETAIL FOR
CORROSION RESISTANT API RING GROOVE

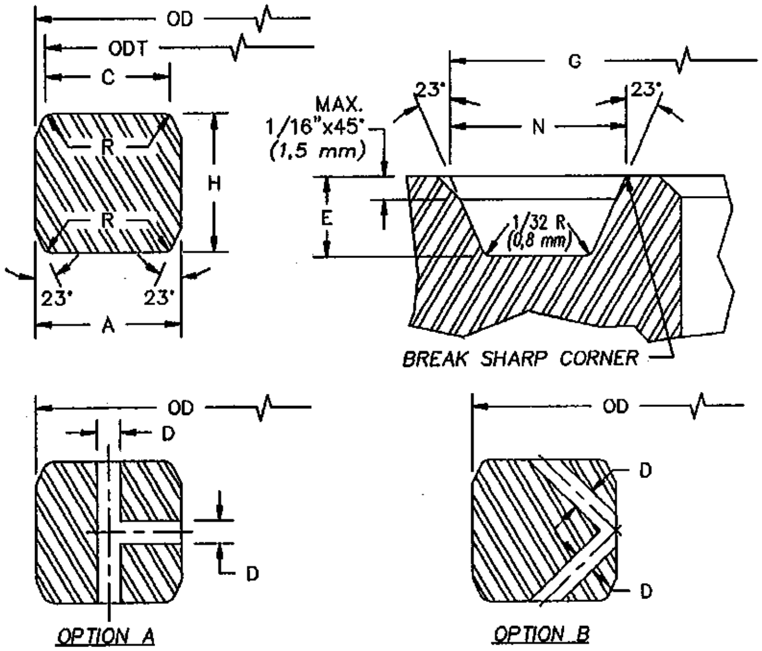


Ring Number	Outside Diameter of Groove *A* in.	(mm)	Width of Groove *B* in.	(mm)	Depth of Groove *C* in.	(mm)
BX-152	3.72	(95,0)	.77	(19,5)	.38	(10,0)
BX-153	4.38	(111,5)	.83	(21,5)	.41	(10,5)
BX-154	5.01	(127,5)	.88	(22,5)	.44	(11,5)
BX-155	6.26	(159,5)	.97	(25,0)	.47	(12,0)
BX-156	9.85	(250,5)	1.20	(31,0)	.58	(15,0)
BX-157	12.10	(307,5)	1.32	(34,0)	.64	(16,5)
BX-158	14.39	(366,0)	1.42	(36,5)	.70	(18,0)
BX-169	7.285	(185,0)	0.842	(21,39)	.52	(13,2)

Ring Number	Outside Diameter of Groove *A* in.	(mm)	Width of Groove *B* in.	(mm)	Depth of Groove *C* in.	(mm)
R-201	2.36	(59,94)	.50	(12,7)	.30	(7,62)
R-205	2.80	(71,12)	.50	(12,7)	.42	(10,67)
R-210	4.20	(106,68)	.66	(16,76)	.39	(9,91)
R-215	5.92	(150,39)	.73	(19,05)	.45	(11,43)

NOTE: *Allow ⅛" or greater for final machining of weld overlay.*

TABLE 906.1
API TYPE SBX PRESSURE ENERGIZED RING GASKETS



TOLERANCES (mm)

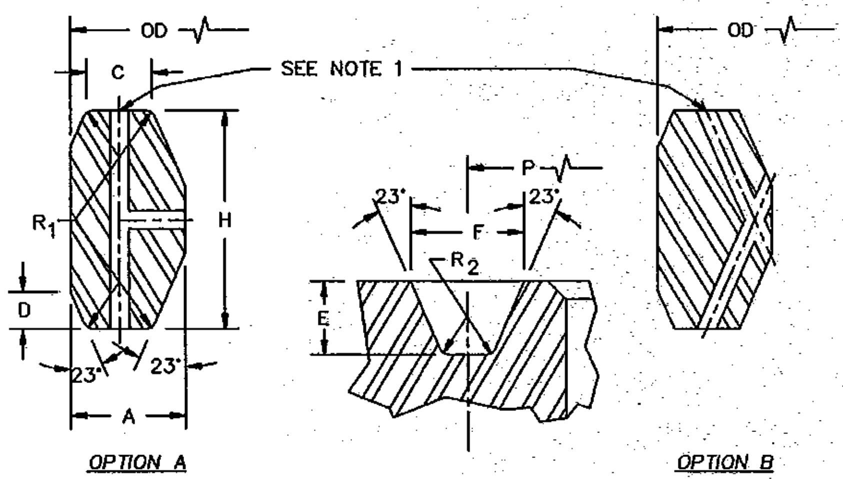
A* (width of ring)	+0.008,–0.000	(+0,2,–0)
C (width of flat)	+0.006,–0.000	(+0,15,–0)
D (height of chamfer)	+0.000,–0.03	(+0,–0,8)
E (depth of groove)	+0.02,–0	(+0,8,–0)
F (width of groove)	±0.008	(±0,2)
H* (height of ring)	+0.008,–0.000	(+0,2,–0)
OD (OD of ring)	+0.020,–0.000	(+0,5,–0)
P (average pitch diameter of groove)	±0.005	(±0,1)
R_1 (radius in ring)	±0.02	(±0,5)
R_2 (radius in groove)	max	
23° (angle)	±½°	

NOTE 1: *Radius "R" shall be 8 to 12 percent of the gasket height "H."*
NOTE 2: *Two pressure passage holes in the SBX ring cross section prevent pressure lock when connections are made up underwater. Two options are provided for drilling the pressure passage holes.*

*A plus tolerance of 0.008 in. (0,2 mm) for width A and height H is permitted, provided the variation in width or height of any ring does not exceed 0.004 in. (0,1 mm) throughout its entire circumference.

Ring Number	Nominal Size in.	(mm)	Outside Diameter of Ring OD in.	(mm)	Height of Ring H in.	(mm)	Width of Ring A in.	(mm)	Diameter of Flat ODT in.	(mm)	Width of Flat C in.	(mm)	Hole Size D in.	(mm)	Depth of Groove E in.	(mm)	Outside Diameter of Groove G in.	(mm)	Width of Groove N in.	(mm)
SBX 151	1 13/16	(46)	3.008	(76,40)	0.379	(9,63)	0.379	(9,63)	2.954	(75,03)	0.325	(8,26)	0.06	(1,5)	0.22	(5,56)	3.062	(77,79)	0.466	(11,84)
SBX 152	2 1/16	(52)	3.334	(84,68)	0.403	(10,24)	0.403	(10,24)	3.277	(83,24)	0.346	(8,79)	0.06	(1,5)	0.23	(5,95)	3.395	(86,23)	0.498	(12,65)
SBX 153	2 9/16	(65)	3.974	(100,94)	0.448	(11,38)	0.448	(11,38)	3.910	(99,31)	0.385	(9,78)	0.06	(1,5)	0.27	(6,75)	4.046	(102,77)	0.554	(14,07)
SBX 154	3 1/16	(78)	4.600	(116,84)	0.488	(12,40)	0.488	(12,40)	4.531	(115,09)	0.419	(10,64)	0.06	(1,5)	0.30	(7,54)	4.685	(119,00)	0.606	(15,39)
SBX 155	4 1/16	(103)	5.825	(147,96)	0.560	(14,22)	0.560	(14,22)	5.746	(145,95)	0.481	(12,22)	0.06	(1,5)	0.33	(8,33)	5.930	(150,62)	0.698	(17,73)
SBX 156	7 1/16	(179)	9.367	(237,92)	0.733	(18,62)	0.733	(18,62)	9.263	(235,28)	0.629	(15,98)	0.12	(3,0)	0.44	(11,11)	9.521	(241,83)	0.921	(23,39)
SBX 157	9	(228)	11.593	(294,46)	0.826	(20,98)	0.826	(20,98)	11.476	(291,49)	0.709	(18,01)	0.12	(3,0)	0.50	(12,70)	11.774	(299,06)	1.039	(26,39)
SBX 158	11	(279)	13.860	(352,04)	0.911	(23,14)	0.911	(23,14)	13.731	(348,77)	0.782	(19,86)	0.12	(3,0)	0.56	(14,29)	14.064	(357,23)	1.149	(29,18)
SBX 159	13 5/8	(346)	16.800	(426,72)	1.012	(25,70)	1.012	(25,70)	16.657	(423,09)	0.869	(22,07)	0.12	(3,0)	0.62	(15,88)	17.033	(432,64)	1.279	(32,49)
SBX 160	13 5/8	(346)	15.850	(402,59)	0.938	(23,83)	0.541	(13,74)	15.717	(399,21)	0.408	(10,36)	0.12	(3,0)	0.56	(14,29)	16.063	(408,00)	0.786	(19,96)
SBX 161	16 5/8	(422)	19.347	(491,41)	1.105	(28,07)	0.638	(16,21)	19.191	(487,45)	0.482	(12,24)	0.12	(3,0)	0.67	(17,07)	19.604	(497,94)	0.930	(23,62)
SBX 162	16 5/8	(422)	18.720	(475,49)	0.560	(14,22)	0.560	(14,22)	18.641	(473,48)	0.481	(12,22)	0.06	(1,5)	0.33	(8,33)	18.832	(478,33)	0.705	(17,91)
SBX 163	18 3/4	(476)	21.896	(556,16)	1.185	(30,10)	0.684	(17,37)	21.728	(551,89)	0.516	(13,11)	0.12	(3,0)	0.72	(18,26)	22.185	(563,50)	1.006	(25,55)
SBX 164	18 3/4	(476)	22.463	(570,56)	1.185	(30,10)	0.968	(24,59)	22.295	(566,29)	0.800	(20,32)	0.12	(3,0)	0.72	(18,26)	22.752	(577,90)	1.290	(32,77)
SBX 165	21 1/4	(540)	24.595	(624,71)	1.261	(32,03)	0.728	(18,49)	24.417	(620,19)	0.550	(13,97)	0.12	(3,0)	0.75	(19,05)	24.904	(632,56)	1.071	(27,20)
SBX 166	21 1/4	(540)	25.198	(640,03)	1.261	(32,03)	1.029	(26,14)	25.020	(635,51)	0.851	(21,62)	0.12	(3,0)	0.75	(19,05)	25.507	(647,88)	1.373	(34,87)
SBX 169	5 1/8	(131,18)	6.831	(173,51)	0.624	(15,85)	0.509	(12,93)	6.743	(171,29)	0.421	(10,69)	0.06	(1,5)	0.38	(9,65)	6.955	(176,66)	0.666	(16,92)

TABLE 906.2
API TYPE SRX PRESSURE ENERGIZED RING GASKETS



TOLERANCES (mm)

*A**	(width of ring)	+0.008,–0.000 (+0,20,–0)
C	(width of flat)	+0.006,–0.000(+0,15,–0)
D	(hole size)	±0.02 (±0,5)
E	(depth of groove)	+0.02,–0 (+0,5,–0)
G	(OD of groove)	+0.004,–0.000 (+0,10,–0)
*H**	(height of ring)	+0.008,–0.000 (+0,20,–0)
N	(width of groove)	+0.004,–0.000 (+0,10,–0)
OD	(OD of ring)	+0.000,–0.006 (+0,–0,15)
ODT	(OD of flat)	±0.002 (±0,05)
R	(radius in ring)	see note
23°	(angle)	±¼°

*A plus tolerance of in. 0.008 (0,2 mm) for width *A* and height *H* is permitted, provided the variation in width or height of any ring does not exceed 0.004 in. (0,1 mm) throughout its entire circumference.

NOTE 1: *The two pressure passage holes illustrated in the SRX ring cross section prevent pressure lock when connections are made up underwater. Hole diameter shall be .06" (7 mm). Two options are provided for drilling the pressure passage hole.*

Ring Number	Pitch Diameter of Ring and Groove P in.	(mm)	Outside Diameter of Ring OD in.	(mm)	Width of Ring A in.	(mm)	Width of Flat C in.	(mm)	Height of Outside Bevel D in.	(mm)	Height of Ring H in.	(mm)	Radius in Ring R_1 in.	(mm)	Depth of Groove E in.	(mm)	Width of Groove F in.	(mm)	Radius in Groove R_2 in.	(mm)	Approx. Distance Between Made Up Flanges S
SRX 201	1.813	(46,04)	2.026	(46,04)	0.226	(5,74)	0.126	(3,20)	0.057	(1,45)	0.445	(11,30)	0.02‡	(0,5)	0.16	(4,06)	0.219	(5,56)	0.03	(0,8)	—
SRX 205	2.250	(57,15)	2.453	(62,31)	0.219	(5,56)	0.120	(3,05)	0.072†	(1,83)	0.437	(11,10)	0.02‡	(0,5)	0.16	(4,06)	0.219	(5,56)	0.02	(0,5)	—
SRX 210	3.500	(88,90)	3.844	(97,63)	0.375	(9,53)	0.213	(5,41)	0.125†	(3,18)	0.750	(19,05)	0.03‡	(0,8)	0.25	(6,35)	0.375	(9,53)	0.03	(0,8)	—
SRX 215	5.125	(130,18)	5.547	(140,89)	0.469	(11,91)	0.210	(5,33)	0.167†	(4,24)	1.000	(25,40)	0.06‡	(1,5)	0.31	(7,87)	0.469	(11,91)	0.03	(0,8)	—

†Tolerance on these dimensions is +0 –.015 (+0 –0,4)

‡Tolerance on these dimensions is +0.02 –0 (+0,5 –0)

conform to Table 901.5, or other weld preparations may be employed where the strength of the overlay alloy equals or exceeds the strength of the base materials.

Dimensions for Type 17SS flange ring grooves shall conform to Table 906.1.

(b) **Integral Flange Exceptions.** Type 17SS flanges used as end connections on subsea completion equipment may have entrance bevels, counterbores or recesses to receive running/test tools, plugs, etc. The dimensions of such entrance bevels, counterbores, and recesses are not covered by this specification and may exceed the B dimension of the Tables. The manufacturer shall ensure that the modified flange designs shall meet the requirements of Section 303.3 of this specification.

(c) **Threaded Flanges.** Threaded flanges shall not be used on subsea completions equipment, except as provided in Section 903. Dimensions of threaded flanges, if used, shall comply with API Specification 6A, Section 901.

(d) **Weld Neck Flanges.** Bore and Wall Thickness: The bore diameter J shall not exceed the values shown in Table 901.2. The specified bore shall not result in a weld-end wall thickness less than 87.5 percent of the nominal wall thickness of the pipe to which the flange is to be attached

Weld End Preparation: Dimensions for weld end preparation shall conform to Figure 901.2.

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

NOTE: *Due to smaller maximum bore dimensions, Type 17SS weld neck flanges are not intended to be welded to wellhead and completion equipment in this specification. Their purpose is to provide a welding transition between a flange and a pipe.*

901.2b(3) Ring Grooves. Corrosion resistant inlayed ring grooves for 2" (52 mm) through 11" (279 mm) API Type 17SS flanges shall comply with the requirements of Table 901.5 and Section 404.3.

Corrosion resistant inlays for 13 5/8" (346 mm) through 21 1/4" (540 mm), 5000 psi, Type 6BX flanges shall comply with the requirements of API Specification 6A, Section 901.

901.2c Standard Subsea Flanges — Working Pressures 10,000 or 15,000 Psi (69,0 or 103,5 MPa) (Type 6BX). Standard flanges for use in 10,000 or 15,000 psi (69,0 or 103,5 MPa) working pressure subsea completions equipment shall comply with the requirements for API Type 6BX flanges, as defined in API Specification 6A. These flanges are ring joint type flanges, designed for face-to-face make-up. The connection make-up bolting force reacts primarily on the flange face.

Corrosion resistant inlayed ring grooves for API Type 6BX flanges shall comply with the requirements of API 6A, Section 901.

901.2d Segmented Flanges — Working Pressure 5000 Psi. Segmented flanges should not be used except where closely spaced multiple connections do not permit the use of full size standard flanges. If segmented flanges are used, there shall be at least two pressure controlling valves between the segmented flange and the wellhead. Segmented flanges for use on subsea completion equipment shall comply with the requirements of API Specification 6A, Section 901. These flanges are ring joint type flanges, designed for face-to-face make-up. The connection make-up bolting force reacts primarily on the flange face.

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

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

The large angular rotations often required to align mating segmented flanges may induce excessive torsional loads which could damage flexible piping (ref. API Recommended Practice 17B). If segmented flanges are used with flexible piping, the loads acting on these flanges and flexible piping shall not exceed the limits established by their respective manufacturers.

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

Corrosion-resistant inlayed ring grooves are not allowed for segmented flanges (reference API Specification 6A, Section 901.2d(5)). Therefore, segmented flanges must be manufactured from corrosion-resistant materials.

901.2e Swivel Flanges — Working Pressures 5000 or 10,000 Psi (34,5 or 69,0 MPa) (Type 17SV)

901.2e(1) General. Type 17SV flanges are multiple-piece assemblies in which the flange rim is free to rotate relative to the flange hub. Type 17SV flanges may be used on subsea completions equipment where it is difficult or impossible to rotate either of the flange hubs to align the mating bolt holes. Type 17SV flanges mate with standard Type 6BX and 17SS flanges of the same size and pressure rating.

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

901.2e(2) Dimensions.

(a) Standard Dimensions.

Dimensions for Type 17SV integral flanges shall conform to Tables 901.3 and 901.4.

Dimensions for Type 17SV flange weld end preparations shall conform to Figure 901.2.

Dimensions for rough machining of ring grooves for corrosion resistant inlays shall conform to Table 901.5, or other weld preparations may be employed where the strength of the overlay alloy equals or exceeds the strength of the base materials.

Dimensions for Type 17SV flange ring grooves shall conform to Table 906.1.

901.2f Flange Face. Flange faces shall be fully machined. The nut bearing surface shall be parallel to the flange gasket face within one degree. The back face may be fully machined or spot faced at the bolt holes. The thickness of Type 17SS and Type 17SV flanges after facing shall meet the dimensions of Tables 901.2 through 901.4 as applicable. The thickness of API Type 6BX flanges shall meet the requirements of API Specification 6A, Section 901.

901.2g Gaskets. Type 6BX, 17SS and 17SV flanges in subsea completion equipment shall use Type BX or SBX gaskets in accordance with Section 906 of this Specification. If these flanges are to be made up underwater per the manufacturer's written specification, they shall use internally cross drilled Type SBX ring gaskets to prevent fluid entrapment between the gasket and the ring groove during flange make-up.

Segmented flanges in subsea completion equipment shall use Type RX or SRX gaskets in accordance with Section 906 of this specification. If segmented flanges are to be made up underwater per the manufacturer's written specification, they shall use internally cross drilled Type SRX ring gaskets.

901.2h Corrosion Resistant Ring Grooves. All end and outlet flanges used on subsea completions shall be manufactured from, or inlayed with, corrosion resistant material. Corrosion resistant inlayed BX and RX ring grooves shall comply with API Specification 6A, Section 901.

Prior to application of the inlay, preparation of the BX and RX ring grooves shall conform to the dimensions of Table 901.5 of API Specification 6A or Table 901.5 of this specification as applicable, or other weld preparations may be employed where the strength of the inlay alloy equals or exceeds the strength of the base material. The inlay material shall be compatible per manufacturer's written specification with both the base metal of the flange and the ring gasket material (welding, galling, and dissimilar metals corrosion).

901.2i Ring Groove Surface. All 23° surfaces on BX (SBX) ring grooves shall have a surface finish no rougher than 32 RMS. All 23° surfaces on RX (SRX) ring grooves shall have a surface finish no rougher than 63 RMS.

901.3 MATERIALS. Flange material shall conform to the requirements in Sections 400 and 500 of this specification as applicable.

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

901.5 MARKING. Flanges shall be marked to conform with Section 700 of this specification.

901.6 STORING AND SHIPPING. All flanges shall be stored and shipped in accordance with Section 800 of this specification.

902 API CLAMP HUB-TYPE CONNECTIONS. API clamp hub-type connections for use on subsea completion equipment shall comply with the dimensional requirements of API Specification 16A, Section 5. All end and outlet clamp hubs used on subsea completion equipment shall have their ring grooves either manufactured from, or inlayed with, corrosion resistant materials.

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

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

API Type threaded connections used on subsea equipment covered by this Specification shall comply with the requirements of API Specification 6A, Sections 302.1(b), 901, 902, and 911, as applicable.

904 OTHER END CONNECTORS (O.E.C.'S). The use of other nonstandard end connectors, such as misalignment connectors, non-API flanges, ball joints, articulated jumper assemblies, or instrument/monitor flanges are allowable in subsea completion equipment if these connectors have been designed, documented and tested in accordance with the requirements established in Section 300 of this specification.

Materials for O.E.C.'s shall meet the requirements of Sections 400 and 500 of this specification. If the connector's primary seals are not metal-to-metal, redundant seals shall be provided. Other end connectors used on subsea completion equipment shall have their ring grooves either manufactured from, or inlayed with, corrosion resistant materials.

API Specification 17D equipment which utilizes O.E.C.'s shall successfully complete the tests required in Sections 307 and 605 of this specification.

O.E.C.'s shall be marked in accordance with Section 700 of this specification.

O.E.C.'s shall be stored and shipped in accordance with Section 800 of this specification.

905 STUDS, NUTS AND BOLTING. Selection of stud, nut and bolting materials and platings should consider seawater induced chloride stress corrosion cracking and corrosion fatigue. Hydrogen embrittlement induced by cathodic protection systems should be considered.

Some high strength bolting materials may not be suitable for service in a seawater environment. Refer to Section 303.4 of this specification.

905.1 API STUDS AND NUTS. The requirements for API studs and nuts apply only to those used in end and outlet connections. Such studs and nuts used on subsea completion equipment covered by this Specification shall comply with API Specification 6A, Section 903.

905.2 OTHER STUDS, NUTS AND BOLTING. All other studs, nuts and bolting used on API Specification 17D equipment shall comply with the manufacturer's written specifications.

905.3 MAKE-UP TORQUE REQUIREMENTS. Make-up torque requirements shall comply with Section 303.4 of this specification for API Specification 17D equipment.

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

The use of calibrated torque tools should be considered to ensure accurate make-up torques.

906 RING GASKETS.

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

Connections which will not be made up underwater may use standard and API Type BX or RX gaskets which comply with API Specification 6A.

Other proprietary gaskets shall conform to the manufacturers' written specification.

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

906.2 DESIGN.

906.2a Dimensions. Type SBX and SRX ring gaskets shall conform to the dimensions and tolerances specified in Tables 906.1 and 906.2 and must be flat within 0.2% of ring outside diameter to a maximum of 0.015 inches (0.4 mm).

906.2b Surface Finish. All 23° surfaces on Type SBX gaskets shall have a surface finish no rougher than 32 RMS. All 23° surfaces on Type SRX gaskets shall have a surface finish no rougher than 63 RMS.

906.2c Pressure Passage Hole. Each BX and RX gaskets shall have one pressure passage hole drilled through its height as shown in API Specification 6A, Tables 904.2 and 904.3.

API Type BX and RX ring gaskets are not suitable for connections which will be made up underwater since fluid trapped in the ring groove may interfere with proper make up. Type SBX or SRX vented ring gaskets shall be used in place of Type BX or RX gaskets on API Type flange connections made up underwater per the manufacturer's written specification. Type SBX and SRX ring gaskets shall conform to Tables 906.1 and 906.2, respectively, of this specification.

If other types of end connectors are used on API Specification 17D equipment which will be made up underwater per the manufacturer's written specification, then means shall be provided to vent trapped pressure between the gasket and the connector.

906.2d Reuse of Gaskets. Except for testing purposes, API ring gaskets shall not be reused.

906.3 MATERIALS.

906.3a Ring Gasket Materials. Ring gaskets used for all pressure-containing flanged and clamped subsea connections shall be manufactured from corrosion-resistant materials. Gasket materials shall conform to the requirements of API Specification 6A, Section 405.

906.3b Coatings and Platings. Coatings and platings used on API ring gaskets to aid seal engagement while minimizing galling shall not exceed 0.0005 inch (0.01 mm) thickness.

906.4 MARKING. Gaskets shall be marked to conform with Section 700 of this specification.

906.5 STORING AND SHIPPING. Gaskets shall be stored and shipped in accordance with Section 800 of this Specification.

907 TREE CONNECTORS AND TUBING HANGER SPOOLS.

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

907.1a Tree/Spool Connectors.

907.1a(1) Uses — Tree Connectors are used to land and lock the subsea tree to either a subsea wellhead or a tubing hanger spool. Connectors are also used to land and lock the tubing hanger spool (if used) to the wellhead. The connector may also provide orientation between the subsea wellhead, tubing hanger, and tree.

907.1a(2) Types, Sizes and Pressure Ratings — Three types of tree/spool connectors are commonly used:

- Hydraulic Remote Operated
- Mechanical Remote Actuated
- Mechanical Diver/ROV Operated

All connectors shall be designated by size, pressure rating, and the profile type of the subsea wellhead to which they will be attached (see Table 1001.1 of Subsea Wellhead and Tubing Hanger Equipment Section of this specification). Tree/spool connectors shall conform to maximum standard pressure ratings of 5,000, 10,000, or 15,000 psi (34,5; 69,0 or 103,5 MPa), as applicable. NOTE TO USER: *The pressure rating selected should be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree whichever is greater.*

907.1b Tubing Hanger Spools.

907.1b(1) Uses — Tubing hanger spools are commonly used to:

- Provide a crossover between wellheads and subsea trees made by different equipment manufacturers.
- Crossover between different sizes and/or pressure ratings of subsea wellheads and trees.
- Provide a surface for landing and sealing a tubing hanger if the wellhead is damaged or is not designed to receive the hanger.
- Provide a means for attaching the Flowline Connector Support Frame, or other guidance equipment, to the subsea wellhead.

907.1b(2) Types, Sizes and Pressure Rating — The tubing hanger spool shall be designated by size, pressure rating, and the profile types of its top and bottom connections. Top connections are commonly either hub or mandrel type connections. The tubing hanger spool and connector may be manufactured as an integral unit. Tubing spools shall conform to standard pressure ratings of 5,000, 10,000, or 15,000 psi (34,5; 69,0 or 103,5 MPa), as applicable. When the tubing hanger spool and connector are manufactured as an integral unit, then the pressure rating shall apply to the unit as a whole. Pressure rating selected shall be equal to or greater than the maximum operating control pressure of the SCSSV or rated working pressure of the subsea tree whichever is greater.

907.2 DESIGN.

907.2a Loads/Conditions. As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree connector and tubing hanger spool:

- Internal and external pressure:
  Pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed)
- Mechanical preloads
- Riser bending and tension loads
- Environmental loads
- Fatigue considerations
- Mechanical installation (impact) loads
- Hydraulic coupler thrust and/or preloads
- Thermal Expansion (trapped fluids, dissimilar metals)
- BOP loads
- Tree loads
- Flowline loads
- Installation/workover
- Overpull
- Corrosion

The manufacturer shall document the load/capacity for the tree/spool connector using the load chart format illustrated in Figure 907.1. This format relates pressure to allowable bending moment for various tensions. The manufacturer shall state whether the basis of the graphs is stress limits or gasket separation limits. Analytical design methods shall conform to Section 300 of this specification.

907.2b Design and Functional Requirements.

907.2b(1) Tree/spool connector and tubing hanger spools shall conform to Section 300 of this specification.

907.2b(2) The tree/spool connector and/or tubing hanger spool shall provide preload and structural strength to provide sealing within the maximum rated loads as shown on the manufacturer's load/capacity chart (refer to Figure 907.1).

907.2b(3) Hydraulically actuated tree and tubing hanger spool connectors shall be capable of containing hydraulic release pressures of at least 25% above normal operating release pressures in the event that normal operating release pressure is inadequate to effect release of the connector. The manufacturer shall document of both normal and maximum operating release pressures.

907.2b(4) Hydraulically actuated tree and tubing hanger spool connectors shall be designed with a secondary release method.

907.2b(5) Remotely-operated tree connector and/or tubing hanger spool connectors shall be equipped with an external position indicator.

907.2b(6) Hydraulic tree and tubing hanger spool connectors shall be designed to prevent release due to loss of hydraulic locking pressure.

907.2b(7) Seal surfaces for tree and tubing hanger spool connectors which engage metal-to-metal seals shall be inlayed with corrosion resistant material which is compatible per the manufacturer's written specification with both the base metal of the connector or spool and the seal material. Inlays are not required if the base metal is corrosion resistant, or if redundant nonmetallic seals are used.

907.2b(8) Means shall be provided for testing all primary seals in the connector cavity to the rated working pressure of the tree/spool connector or tubing hanger, whichever is lower.

907.3 MATERIALS. Materials used in tree/spool connectors and tubing hanger spools shall comply with the requirements of Section 400 of this specification. The wetted surfaces of the tree connector/spool and/or tubing hanger spool should have a materials class rating and temperature classification appropriate for the anticipated fluid, pressure, and temperature.

907.4 TESTING.

907.4a General. The following test procedure applies to both mechanical and hydraulic connectors.

907.4b Performance verification testing shall comply with the requirements of Section 307 of this specification.

907.4c Factory Acceptance Testing. All wellbore pressure containing/controlling components shall comply with the hydrostatic test requirements of Section 600 of this specification.

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

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

After final assembly, the connector shall be tested for proper operation and interface per the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test per the requirements of Section 908.5b(3)(b) of this specification.

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

907.5 WELDING. Welding for tree/spool connectors and tubing hanger spools shall comply with the requirements of Section 500 of this specification.

907.6 MARKING. Tree/spool connectors and tubing hanger spools shall be marked in accordance with Section 700 of this specification.

907.7 STORING AND SHIPPING. Tree/spool connectors and tubing hanger spools shall be shipped and stored in accordance with Section 800 of this specification.

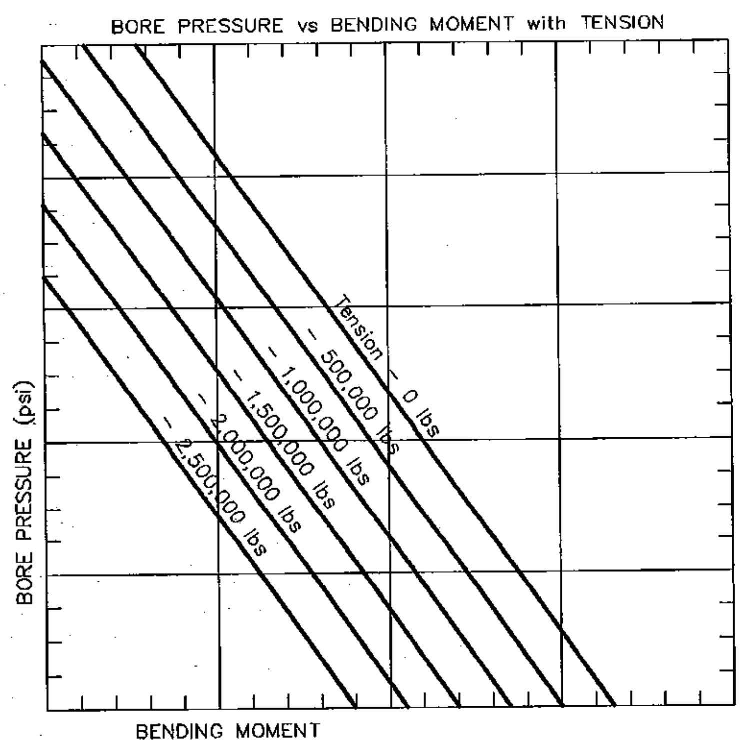


FIGURE 907.1

908 VALVES, VALVE BLOCKS AND ACTUATORS.

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

908.1a Pressure Ratings. Valves and valve blocks shall conform to standard maximum pressure ratings of 5,000, 10,000, or 15,000 psi (34,5; 69,0 or 103,5 MPa) as covered by this specification.

908.1a(1) Flanged End Valves.

Flanged Valves. Valves and valve blocks having API type flanged end connections shall use integral, welding neck, or blind ring-joint flanges as specified in Section 901 of this specification.

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

908.1a(2) Other End Connector Valves. API threaded end valves shall only be supplied in accordance with Section 302.1 of API Specification 6A and Section 903 of this document. API type clamp-type connections shall conform to API Specification 16A. Other end connectors shall conform to API Specification 6A, Section 918.

908.1b Temperature Ratings. Subsea valves, valve blocks and actuators shall conform to the temperature ratings of Section 302.2 of this specification.

908.1c Materials Class Ratings. Materials of construction shall comply with Section 302.3 of this specification.

908.1d Class of Service. Subsea valves shall be designed to operate in one of the following classes of service:

- Standard Service
- Sandy Service (see Section 908.2a(2)(c))

908.2 DESIGN.

908.2a Valves and Valve Blocks.

908.2a(1) General. Subsea tree valves and valve blocks covered under this specification shall be designed, manufactured and tested in accordance with this specification.

Valves and valve blocks used in the subsea tree bores and tree piping shall conform to the applicable end to end and bore dimensional requirements of API Specification 6A, Section 905. Other valve and valve block dimensions shall be in accordance with Sections 901 through 906 of this specification.

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

For valves and valve blocks used in TFL applications, the design shall also comply with Section 4.2b of API Recommended Practice 17C.

908.2a(2) Valves.

(a) All subsea valves shall meet the design requirement of Section 300 of this specification.

(b) Valves rated for standard service shall meet the design requirements of either Section 905 of API Specification 6A except for Section 905.3b(6), or API Specification 14D, class 1 or 2.

(c) Valves rated for sandy service shall comply with API Specification 14D, class 2.

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

(e) Body cavity integrity. All valve body cavities shall be designed to contain hydrostatic test pressure in accordance with Section 908.5 of this specification.

(f) Valve bore sealing mechanism. All subsea valve bore sealing mechanisms (unidirectional or bidirectional) shall be designed to contain the rated working pressure and shall be tested in accordance with Section 908.5 of this specification.

(g) Manufacturers of subsea valves shall document design and operating parameters of the valve as listed in Table 908.2.

908.2a(3) Valve Blocks.

(a) Valve blocks shall meet the design requirements in Section 300 of this specification, and Section 905 of API Specification 6A.

(b) Valve blocks shall be designed for loading in accordance with Section 907.2a of this specification.

908.2b Actuators.

908.2b(1) General. The design of subsea valve actuators shall comply with the following:

(a) Subsea valve actuators shall meet the design requirements in Section 300 of this specification.

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

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

(d) Subsea actuator covered by this specification shall be designed by the manufacturer for nominal hydraulic working pressure rating of either 1500 or 3000 psi (10,3 or 20,7 MPa), or per the manufacturer's specification.

TABLE 908.2
DESIGN AND OPERATING PARAMETERS OF VALVES AND ACTUATORS

A. Valve:

1 Nominal bore size ______
2 Working pressure ______
3 Class of service ______
4 Temperature classifications ______
5 Type and size end connections ______
6 Valve stroke ______
7 Overall external dimensions and weight ______
8 Materials class rating ______
9 Failed position (open, closed, in place)** ______
10 Unidirectional or bidirectional ______

B. Actuator:

1 Minimum operating pressure ______
2 Maximum working pressure ______
3 Temperature classifications ______
4 Actuator volume displacement ______
5 Override force or torque required* ______
6 Maximum override force or torque* ______
7 Overall external dimensions and weight ______
8 Make and Model number of valves the actuator is designed for: ______
______

C. Valve/Hydraulic Actuator Assembly:

At maximum rated depth of assembly and maximum rated bore pressure, hydraulic pressure in psig the valve will:

1 Start to open from previously closed position ______
2 Fully open ______
3 Start to close from previously open position ______
4 Fully closed ______

At maximum rated depth of assembly and 0 bore pressure, hydraulic pressure in psig the valve will:

5 Start to open from previously closed position ______
6 Fully open ______
7 Start to close from previously open position ______
8 Fully closed ______
9 Nominal depth rating per 908 2b(3)(h) ______

*If equipped with manual or ROV override

**Where applicable

908.2b(2) Manual Actuators.

(a) The design of the manual actuation mechanism shall take into consideration the ability of divers, atmospheric diving systems and/or ROV's, for operations. Manual valves shall be operable by divers and/or ROV's.

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

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

(d) Intervention fixtures for manual valve actuators shall comply with Section 921 of this specification.

908.2b(3) Hydraulic Actuators.

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

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

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

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

- Rotation type override shall open the valve with a counter-clockwise rotation as viewed from the end of the stem on fail close valves.
- Push-pull type override for fail closed valve shall open the valve with a push on the override.
- For fail open valves, the manufacturers shall document the method of override.

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

(f) Actuator manufacturer shall document design and operating parameters, as listed in Table 908.2.

(g) Actuator manufacturer shall document the maximum depth ratings at the operating conditions of the valve/actuator assembly per Section 908.2c(4) of this specification.

908.2c Valve/Hydraulic Actuator Assembly.

908.2c(1) The subsea valve and hydraulic actuator assembly shall be assembled with an actuator designed for that valve.

908.2c(2) The subsea valve and hydraulic actuator assembly design may utilize valve bore pressure and/or spring force to assist opening and/or closing of the valve.

908.2c(3) Means shall be provided to prevent wellbore pressure from overpressuring the actuator.

908.2c(4) Manufacturer shall specify the maximum water depth rating of the valve/actuator assembly. Subsea valve and actuator assemblies designated as fail closed (open) shall be designed and fabricated to be capable of fully closing (opening) the valve at the maximum rated water depth under all of the following conditions:

(a) From 14.7 psia (0,10 MPa) to maximum working pressure of the valve in the valve bore.

(b) Differential pressure equal to the bore pressure across the valve bore sealing mechanism at the time of operation.

(c) External pressure on the valve/actuator assembly at the maximum rated water depth using seawater specific gravity of 1.03.

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

(e) 114.7 psia (0,80 MPa) plus seawater ambient hydrostatic pressure at the maximum rated depth of the assembly acting on the actuator piston in the opening (closing) direction.

NOTE: *The maximum water depth rating is calculated using the above set of operating conditions for the purpose of standardization and does not necessarily represent operating limitation. Additional information relating to water depth and valve/actuator performance may be supplied by the manufacturer, such as for wire/coil tubing shearing requirements.*

908.2d Other Pressure Boundary Penetrations. Other pressure boundary penetrations such as grease/bleeder fittings which penetrate directly into the wellbore shall conform to Section 606 of this specification.

908.3 MATERIALS. All pressure containing and pressure controlling parts of subsea valves, valve blocks and actuators shall be made of materials which meet the applicable requirements of Section 400 of this specification. In addition to end and outlet connections, valve bonnet gasket sealing surfaces shall be manufactured from or inlayed with corrosion resistant material.

908.4 WELDING. Welding requirements shall conform to Section 500 of this specification.

908.5 TESTING.

908.5a Performance Verification Testing. Performance verification testing is required to qualify specific valve and valve actuator designs manufactured under this specification.

908.5a(1) Subsea valve actuators shall be tested in accordance with Section 307 of this specification.

908.5a(2) Standard service subsea valves and actuator shall be tested in accordance with Section 307 of this specification.

908.5a(3) Sandy service subsea valves shall be tested in accordance with API Specification 14D, Section 4.6 in addition to tests as specified in Section 307 of this specification.

908.5a(4) Subsea valve and actuator assemblies shall be tested to demonstrate the performance limits of the assembly. Unidirectional valves shall be tested with pressure applied in the intended direction. Bidirectional valves shall be tested with pressure applied in both directions in separate tests.

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

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

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

908.5b Factory Acceptance Testing. Each subsea valve and valve actuator shall be subjected to a hydrostatic and operational test to demonstrate the structural integrity and proper assembly and operation of each completed valve and/or actuator.

908.5b(1) Subsea Valve. Each subsea valve shall be factory acceptance tested in accordance with API Specification 6A, Section 605.9.

908.5b(2) Subsea Valve Gas Tests. Valve gas testing is not required by this specification. However, if specified by the manufacturer, gas tests shall be performed in accordance with API Specification 6A, Section 605.9f, or the manufacturer's written specification.

908.5b(3) Subsea Valve Actuator.

(a) **Hydrostatic Shell Test.** Each actuator cylinder and piston shall be subjected to a hydrostatic test to demonstrate structural integrity. The test pressure shall be a minimum of 1.5 times the nominal hydraulic working pressure rating of the actuator. No leakage shall be allowed. After successful completion of the hydrostatic test, each actuator cylinder and piston shall be marked with the test pressure, in accordance with Section 908.6 of this specification, to provide future identification of tested pieces. If hydrostatic testing of the cylinder and piston is performed after final actuator assembly, stamping of the piston shall not be required.

(b) **Actuator Seal Test.** The actuator seals shall be pressure tested in two steps by applying pressures of 15% to 25% and a minimum of 100% of the nominal hydraulic rated working pressure of the actuator. No seal leakage shall be allowed. The test media shall be specified by the manufacturer. The minimum test duration for each test pressure shall be three minutes. The test period shall not begin until the test pressure has been reached and has stabilized. The test gage pressure reading and time at the beginning and at the end of each pressure holding period shall be recorded.

The low pressure test is not applicable for flow-by type actuators.

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

908.5b(4) Testing of Valve/Actuator Assembly. After final assembly, each valve/actuator assembly shall be subjected to a functional test to demonstrate proper assembly and operation per manufacturer's written specification. The functional test shall be performed by the subsea valve/actuator assembler. All test data shall be recorded on a data sheet and shall be maintained by the subsea valve/actuator assembler for at least five years. The test data sheet shall be signed and dated by the person(s) performing the functional test(s).

The subsea valve and actuator assembly shall meet the testing requirement of Sections 908.5b(1) and 908.5b(3) of this specification except that the hydrostatic shell test need not be repeated if they have been performed on the valve and actuator separately.

Valves used in TFL service shall be drift tested in accordance with API Recommended Practice 17C, Section 4.3a.

908.6 MARKING. All subsea valves and subsea valve actuators shall be marked on the exterior surface with the manufacturer's name or trademark, and shall be marked in accordance with all other specific instructions and identifications as stipulated in Section 700 of this specification and as follows:

908.6a Subsea Valve Marking. The valve portion of subsea valve equipment shall be marked as shown in Table 908.6a. The manufacturer may arrange required nameplate markings as suitable to fit available nameplate space.

908.6b Subsea Valve Actuator Marking. The subsea valve actuator shall be marked as shown in Table 908.6b.

908.6c Subsea Valve and Actuator Assembly Marking. The subsea valve and actuator shall be marked as shown in Table 908.6c.

908.6d Nameplates. Nameplates shall be attached after final coating the equipment. Nameplates should be designed to remain legible for the design life of the valve/actuator.

908.6e Low Stress Marking. All marking done directly on pressure containing components, excluding peripheral marking on API flanges, shall be done using low stress marking methods.

908.6f Flow Direction. All subsea valves which are designed to have unidirectional flow should have the flow direction prominently and permanently marked.

TABLE 908.6A
MARKING FOR SUBSEA VALVES

Marking	Application
1. Manufacturer's name or trademark	Body (if accessible) and nameplate
2. The letters 17D	Nameplate
3. Maximum Rated Working Pressure	Body (if accessible), bonnet and nameplate
4. End flange material, where applicable. The letters API and the API material designation	Flange periphery or nameplate at manufacturer's option
5. Class of service [Standard or Sandy]	Nameplate
6. Material Class Rating	Nameplate
7. Nominal subsea valve size and, when applicable, the restricted or oversized bore	Body or nameplate or both at manufacturer's option
8. Flange and ring-joint designation and size	Subsea valve flange periphery
9. Direction of flow if applicable	Body or nearest accessible location
10. Serial or identification number unique to the particular subsea valve	Nameplate and body if accessible
11. Temperature rating	Nameplate
12. Traceability number if applicable	Bonnet, body
13. PSL level	Body and nameplate

TABLE 908.6B
MARKING FOR SUBSEA VALVE ACTUATOR

Marking	Application
1. Manufacturer's name or trademark	Nameplate and cylinder
2. The letters 17D	Nameplate
3. Maximum working pressure of the cylinder	Nameplate
4. Manufacturer's model number	Nameplate
5. Serial or identification number	Nameplate and cylinder
6. Temperature rating	Nameplate
7. Hydrostatic test pressure	Cylinder
8. PSL level	Nameplate

TABLE 908.6C
MARKING FOR SUBSEA VALVE AND ACTUATOR ASSEMBLY

Marking	Application on Actuator
1. Assembler's name or trademark	Nameplate
2. The letters 17D	Nameplate
3. Assembly serial or identification number	Nameplate
4. Rated water depth	Nameplate

908.7 DOCUMENTATION. The manufacturer shall document the results of subsea tree valve functional tests.

The manufacturer shall document instructions concerning field assembly and maintenance of subsea valves.

908.8 STORING AND SHIPPING. Storing and shipping of subsea valves and actuators shall comply with Section 800 of this specification.

909 TFL WYE SPOOL AND DIVERTER.

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

909.2 DESIGN. Design of TFL WYE spool and diverters shall conform to Section 300 of this specification.

909.2a WYE Spool. All transitional surfaces through the WYE spool shall have chamfered surfaces without reduced diameter or large gaps per the dimensional requirements of Figure 4.3 and 4.4 of API Recommended Practice 17C.

The intersection of the flowloop bore to the vertical wellbore shall comply with the dimensional requirements of API Recommended Practice 17C, Section 4.2.

909.2b Diverter. Provisions shall be made to divert TFL tools to and from the TFL loops per the manufacturer's written specification. Diverter device(s) shall be designed in accordance with Section 4.7 of API Recommended Practices 17C and as described in Section 4.6 of API Recommended Practice 17C.

909.2c Interfaces.

909.2c(1) Master Valve Interface. The WYE spool lower connection shall be sized to mate with the master valve upper connection. This connection shall provide pressure integrity equal to the working pressure of the subsea tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacturer.

909.2c(2) Swab Closure Interface. The upper WYE spool connection shall be sized to mate with the swab closure lower connection. The connection shall provide pressure integrity equal to the working pressure of the subsea tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacture.

909.2c(3) TFL Flowloop Interfaces. The WYE outlet connection shall be sized to mate with either the TFL flowloop piping or the wing valve. This connection shall provide pressure integrity equal to the working pressure of the tree and provide structural strength capable of withstanding the combined loads of full working pressure at the connection plus any externally applied loads specified by the manufacturer. Combined pressure loading, piping preloads (or tension), flowloop makeup and any other applied loads shall not exceed the allowable yield stress of the TFL piping as defined in Section 914 of this specification, nor shall it reduce the flowline internal diameter to below the drift diameter. The bore of the WYE spool shall be aligned with the bore of the flowloop according to the dimensional requirements of API Recommended Practice 17C, Section 4.2. Angles of the TFL WYE spool/flowloop connection shall be less than or equal to 15° from vertical.

909.2c(4) WYE Spool/Diverter Interface. The diverter bore should be concentric with the bore of the flowline and a smooth transition surface should be used to connect the bores. In addition to the straight section of the flowloop above the transition surface, a straight section should also be provided above or below any locking recess or side pocket. The internal surface should provide a smooth transition from cylindrical passage to curvature of the loop.

909.3 MATERIALS. Material requirements shall conform with Section 400 of this specification. All end and outlet connections used on TFL Wye spools shall have their ring grooves either manufactured from, or inlayed with, corrosion resistant materials.

909.4 WELDING. Welding on TFL WYE spools and diverters shall conform to Section 500 of this specification.

909.5 TESTING. All TFL WYE spools and diverters shall be tested in accordance with Section 600 of this specification and drift tested per API Recommended Practice 17C, Section 3.4a.

909.6 MARKING. All TFL WYE spools and diverters shall be marked to conform with Section 700 of this specification.

909.7 STORING AND SHIPPING. All TFL WYE spools and diverters shall be shipped and stored in accordance with Section 800 of this specification.

910 SUBSEA TREE UPPER CONNECTION AND SUBSEA TREE CAP.

910.1 GENERAL. Section 910 addresses the upper terminations of the tree wellbores. The design and manufacture of control couplers/connectors which may or may not be integral with the tree upper connection and/or the tree cap, are not addressed in this document.

910.1a Tree Upper Connection.

910.1a(1) Purpose. To provide an uppermost attachment interface on the tree for connection of:

- A tree running tool used for installation and workover purposes.
- A tree cap.
- Internal crown plugs, if applicable.

910.1a(2) Integral or Nonintegral. The tree upper connection may consist of a separate spool which mechanically connects and seals to the tree upper valve or upper valve block termination. The upper connection may consist of an integral interface profile in or on top of the valve(s) body.

910.1b Tree Cap.

910.1b(1) Non-pressure Containing Tree Cap. Non-pressure containing tree caps protect the tree upper connection and vertical wellbores from possible environmental damage or undesired effects resulting from corrosion, marine growth or potential mechanical loads. Design of non-pressure containing tree caps shall comply with Section 300 of this specification and is not addressed further in this document.

910.1b(2) Pressure Containing Tree Cap. A pressure containing tree cap provides tree top protection and an additional sealing barrier between tree wellbore(s) and the environment.

910.2 DESIGN.

910.2a General. This section applies to both the tree upper connection and pressure containing tree caps. The design of this equipment shall comply with Section 300 of this specification.

910.2a(1) Pressure Rating. The tree upper connection and tree cap shall be rated to the tree working pressure plus an allowance for other loading effects as defined in Section 910.2b of this specification.

910.2a(2) Tree Upper Termination Connection/Profile. The tree upper connection shall provide a locking and sealing profile for the tree running tool and/or tree cap. The design strength of the connection shall be based on loading considerations specified in Section 910.2b of this specification. Independent sealing surfaces shall be provided for each treebore. Corrosion resistant materials or inlays shall be provided for these seal surfaces. Inlays are not required if the base metal is corrosion resistant or if redundant nonmetallic seals are used. The connection shall also provide for passage of wireline tools and shall not limit the drift diameter of the treebore.

910.2a(3) Pressure Containing Tree Caps. The tree cap locking mechanism shall be designed to contain the rated tree working pressure acting over the corresponding seal areas that interface with the upper tree connection.

910.2a(4) Crown Plug Profiles. The effect of wall thickness reductions due to crown plug profiles machined into the tree upper termination shall be included in design analysis and documentation as required in Section 300 of this specification.

910.2b Design Loads/Conditions. Analytical design methods shall conform to Section 300 of this specification. As a minimum, the following loading parameters/conditions shall be considered and doumented by the manufacturer when designing the upper tree connection and tree cap:

- Internal and external pressure

- Pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed)
- Mechanical preloads
- Riser bending and tension loads
- External environmental loads
- Fatigue considerations
- Mechanical installation (impact) loads
- Hydraulic coupler thrust and/or preloads
- Corrosion

910.2c Installation Pressure Test. A means shall be provided to test the upper tree connection and tree cap seal(s) after installation.

910.2d Pressure Venting. The tree cap shall be designed such that any pressure underneath the cap can be vented prior to cap release. This function may be designed to be automatic or to be performed independently.

910.2e Hydraulic Lock. A means shall be provided for the prevention of hydraulic lock during installation of the tree cap.

910.2f Guidance and Orientation. Means shall be provided to guide and orient the tree cap relative to upper tree connection interface.

910.3 MATERIALS. Shall conform to Section 400 of this specification.

910.4 WELDING. Shall conform to Section 500 of this specification.

910.5 TESTING.

910.5a General. The following test procedure applies to upper tree connectors and tree cap connectors having either both mechanical or hydraulic connectors.

910.5b Performance verification testing shall comply with the requirements of Section 307 of this specification.

910.5c Factory Acceptance Testing. All wellbore pressure containing/controlling components shall comply with the hydrostatic test requirements of Section 600 of this specification. Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

After final assembly, the connector shall be tested for proper operation and interface per the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test per the requirements of Section 908.5b(3)(b) of this specification.

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

910.6 MARKING. Shall conform to Section 700 of this specification.

910.7 STORING AND SHIPPING. Shall conform to Section 800 of this specification.

911 TREE GUIDE FRAME.

911.1 GENERAL. The tree guide frame interfaces with the permanent guide base to guide the subsea tree onto the subsea wellhead. The frame may also provide a structural mounting for piping, flowline connection, control interfaces, work platforms, anodes, handling points, and structural protection for tree components.

911.2 DESIGN.

911.2a Permanent Guide Base Interface. The tree guide frame shall interface with standard permanent guide base dimensions, refer to Figure 1001.2. Orientation of the guideline slots in the post shall be specified by the manufacturer.

911.2b Loads. As a minimum, the following loads shall be considered and documented by the manufacturer when designing the tree guide frame:

- Ballast
- Guideline Tension
- Flowline Reaction Loads
- Snag Loads

911.2c Intervention Interfaces. Subsea intervention fixtures attached to the tree guide frame shall be in accordance with Section 921 of this specification.

911.3 MATERIALS. Materials shall conform to Section 405 of this specification.

911.4 WELDING. Welding shall be in accordance with Section 502 of this specification.

911.5 TESTING. Interface testing shall be conducted on the guide frame by installing the frame on a four post 6.0 ft. (1830 mm) radius test stump, or permanent guide base in compliance with Section 911.2a of this specification. A wellhead connector and mandrel or other centralizing means is to be used during the test. Test results shall be in accordance with the manufacturer's written specifications.

911.6 MARKING. The marking shall conform to Section 700 of this specification.

911.7 STORING AND SHIPPING. Storing and shipping shall be in accordance with Section 800 of this specification.

912 TREE RUNNING TOOL.

912.1 GENERAL. This section of the specification addresses the tree running tool as defined in API Recommended Practice 17A Section 2.3.2.3, Paragraph L. No attempt has been made to standardize dimensions of generic types of equipment.

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

912.2 DESIGN. The design of the tree running tool shall comply with Section 300 of this specification.

912.2a Operating Criteria. The manufacturer shall specify the operating criteria for which the tree running/retrieval tool is designed.

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

912.2b Loads. As a minimum, the following loading parameters/conditions shall be considered and documented by the manufacturer when designing the tree running tool.

- Internal and external pressure
- Pressure separation loads shall be based on worst case sealing conditions (leakage to the largest redundant seal diameter shall be assumed).
- Mechanical preloads
- Riser bending and tension loads
- Environmental loads
- Fatigue considerations
- Mechanical installation (impact) loads
- Hydraulic coupler thrust and/or preloads
- Thermal expansion (trapped fluids, dissimilar metals)
- Installation/workover overpull
- Corrosion

The manufacturer shall specify the loads/conditions for which the equipment is designed. The manufacturer shall document the load/capacity for their tree running tool connector using the load chart format illustrated in Figure 907.1, which relates pressure to allowable bending moment for various tensions. The manufacturer shall document whether the basis of the graphs are stress limits or seal separation limits.

912.2c Tree Interface. The tree running tool interfaces with the tree upper connection. This interface shall be designed for emergency release at a running string departure angle as specified by the manufacturer. This release must not cause any damage to the subsea tree such that any other performance requirement is not met.

The tree interface consists of four main component areas:

- Locking Profile and Connector
- Re-entry Seal (where applicable)
- Extension Subs or Seals (where applicable)
- Controls and Instrumentation (where applicable)

912.2c(1) Locking Profile and Connector. The tree running tool shall land and lock onto the locking profile of the upper tree connection and shall withstand separating forces resulting from applied mechanical loads and the rated working pressure of the tree as specified by the manufacturer. The tree running tool connector shall meet functional requirements set forth in Section 907.2b.

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

912.2c(2) Re-entry Seal. An additional sealing barrier to the environment may be included in the interface between the tree running tool interface. This seal encircles all bore extension subs and may enclose hydraulic control circuits. The rated working pressure of this gasket shall be specified by the manufacturer. NOTE TO USER: *The pressure containing capability of this gasket must be at least equal to the tree rated working pressure or the maximum anticipated control pressure of the downhole safety valve, whichever is greater, if the SCSSV control circuit(s) is encapsulated by this seal.*

912.2c(3) Extension Subs or Seals. Extension subs or seals (if used) shall engage mating surfaces in the upper tree connection for the purpose of isolating each bore. The seal mechanism may be either metal-to-metal seals or redundant resilient seals.

In multi-bore applications which use a re-entry seal as described in Section 912.2c(2), each extension sub or seal shall be designed to withstand an external pressure as specified by the manufacturer. NOTE TO USER: *The pressure rating of the extension sub or seal should be equal to the working pressure rating of the tree, or if enclosed, the maximum anticipated control pressure of the SCSSV line, whichever is greater. Each extension sub or seal (if used) shall be designed to an internal pressure rating equivalent to the rated working pressure of the tree.*

912.2c(4) Controls and Instrumentation. Control system and data gathering instrumentation conduits may pass through the tree running tool body. Specific designs and selection of component materials are the responsibility of the manufacturer.

912.2d Running String Interface. The tree running tool may interface with:

- The drilling riser system
- Subsea WCT-BOP or wireline cutter
- Completion riser or stress joint
- Drill pipe or tubing running string
- LWRP

912.2e Tree Guideframe Interface. The tree running tool may have a guidance structure that interfaces with the tree guideframe to provide initial orientation and alignment. If a guidance system is used, it shall be designed to provide alignment to protect seals and seal surfaces from damage in accordance with the manufacturer's written specification.

912.2f Control System Interface. The tree running tool and/or the workover control interface normally transfers control of the subsea tree from the normal surface production control point to the workover control system.

912.3 MATERIALS. Tree running tool portions which may be exposed to wellbore fluids shall be made of materials conforming to Section 400 of this specification and to NACE MR-01-75. Structural materials shall conform to the requirements of Section 400.

912.4 WELDING. Welding shall be in accordance with Section 500 of this specification.

912.5 TESTING.

912.5a General. The following test procedure applies to both mechanical and hydraulic connectors.

912.5b Performance verification testing shall comply with the requirements of Section 307 of this specification.

912.5c Factory Acceptance Testing. All wellbore pressure containing/controlling components shall comply with the hydrostatic test requirements of Section 600 of this specification. Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

After final assembly, the connector shall be tested for proper operation and interface per the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test per the requirements of Section 908.5b(3)(b) of this specification.

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

912.6 MARKING. Identification of each component shall be in accordance with Section 700 of this specification.

912.7 STORING AND SHIPPING. Storing and shipping shall be in accordance with Section 800 of this specification.

913 TREE CAP RUNNING TOOL,

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

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

- actuation of the tree cap connector
- pressure tests of the tree cap seals
- relieve pressure beneath the tree cap
- injection of corrosion inhibitor fluid

913.2 DESIGN. The tree cap running tool shall comply with Section 300 of this specification.

913.2a Operating Criteria. The tree cap running tool shall have operating criteria as set forth in Section 912.2a of this specification.

913.2b Loads. Design loads shall be determined and documented in the same manner as set forth in Section 912.2b of this specification.

913.2c Tree Cap to Running Tool Interfaces.

913.2c(1) The interface between the tree cap and running tool shall be designed for release at a running string departure angle as documented by the manufacturer. This release must not cause any damage to the subsea tree such that any other performance requirement is not met.

913.2c(2) For pressure containing tree caps, any interface connections of related piping, hoses, and valves which could communicate with the seal cavity shall be designed to withstand internal and external pressures as described in Section 912.2 of this specification.

913.3 MATERIALS. Materials selection shall conform to Section 400 of this specification.

913.4 WELDING. Welding requirements shall conform to Section 500 of this specification.

913.5 TESTING.

913.5a General. The following test procedure applies to both mechanical and hydraulic connectors.

913.5b Performance verification testing shall comply with the requirements of Section 307 of this specification.

913.5c Factory Acceptance Testing. All wellbore pressure containing/controlling components shall comply with the hydrostatic test requirements of Section 600 of this specification. Components having multiple bores or ports shall have each bore or port tested individually to verify that there is no intercommunication.

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

After final assembly, the connector shall be tested for proper operation and interface per the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test per the requirements of Section 908.5b(3)(b) of this specification.

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

913.6 MARKING. Component marking shall conform to Section 700 of this specification.

913.7 STORING AND SHIPPING. Storing and shipping shall conform to Section 800 of this specification.

914 TREE PIPING.

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

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

914.2 DESIGN.

914.2a Allowable Stresses. Outboard-tree piping shall conform to the requirements of an existing documented piping code, such as ANSI/ASME B31.4, B31.8 or B31.3. As a minimum, the design rated working pressure of the outboard piping shall be equal to the rated working pressure of the tree. Inboard piping shall be designed in accordance with Section 300 of this specification. In all cases, the following shall be considered:

- Allowable stress at working pressure
- Allowable stress at test pressure
- External loading
- Tolerances
- Corrosion/Erosion allowance
- Temperature
- Wall thinning due to bending

914.2b Other End Connectors. Other end connectors shall comply with Sections 901 through 906 of this specification.

914.2c Operating Parameters. Operating parameters for tree piping shall be based on the service, temperature, material, and external loading on each line. Tree piping may be designed to flex to enable connectors to stroke or to compensate for manufacturing tolerances.

914.2d Tree Piping Flowloops. Tree piping flowloops may be fabricated using forged fittings or prebent sections, or may be formed in a continuous piece. Either "cold" bending or "hot" bending may be used. Bends which are to be used in H_2S service shall conform to the requirements of NACE MR-01-75. Quenched and tempered pipe and tube that is hot bent shall be requenched and tempered after bending per the manufacturer's written specification. Pipe bending tolerances shall conform to the requirements of the Pipe Fabrication Institute (PFI) Standard ES-24.

914.2e TFL Tree Piping Flowloops. TFL piping flowloops shall also be designed in accordance with API Recommended Practice 17C and Section 909 of this specification.

914.2f Pigging. The manufacturer shall document the pigging capability of tree piping.

914.2g Flowline Connector Interface. The tree piping and flowline connector shall be designed to allow flexibility for connection as per the manufacturer's written specification. In the connected position, the combination of induced pipe tension, permanent bend stress, and the specified operating pressure shall not exceed the allowable stress as defined in Section 914.2a of this specification. Stresses induced during makeup may exceed the level in Section 914.2a of this specification, but shall not exceed material minimum yield stress.

914.2h Pressure/Temperature Transducer and Chemical Injection Penetrations. Penetrations located on inboard piping shall be equipped with flanged outlets which conform to Sections 901 or 904 of this specification.

Penetrations located on outboard piping may be either flanged, threaded, or weld on bosses. Threaded connections shall conform to Section 903 of this specification, flanged connections shall conform to Sections 901 or 904, and weld-on bosses shall conform to ANSI B16.11.

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

914.3 MATERIALS. Materials for inboard piping shall conform to Section 400 of this specification. Material for outboard pipe and pipe fittings shall conform to the requirements of the applied design code, e.g., wall thickness calculated using ANSI B31.3 requires the use of B31.3 allowable stresses.

914.4 WELDING. Welding of inboard piping shall be in accordance with Section 500 of this specification. Welding of outboard piping shall conform to the applicable piping code or Section 500 of this specification, whichever is appropriate.

914.5 TESTING. Hydrostatic proof testing shall be conducted on all tree piping. If the tree piping test pressure exceeds the tree rated working pressure, then the tree piping may be subjected to separate hydrostatic shell tests as individual spool pieces rather than as complete assemblies. Test pressures and method for testing inboard piping shall conform to the requirements of Section 600 of this specification. Outboard tree piping shall be tested in accordance with the flowline code as specified in Section 914.2a of this specification.

914.6 MARKING. Marking shall be in accordance with Section 700 of this specification.

914.7 STORING AND SHIPPING. Storing and Shipping shall be in accordance with Section 800 of this specification.

915 FLOWLINE CONNECTOR SYSTEMS.

915.1 GENERAL — TYPES AND USES. This section covers the flowline connector systems which are used to connect subsea flowlines and umbilicals to subsea trees. Electrical connection and component equipment is beyond the scope of this specification.

The flowline connector system may utilize various installation methods, such as first end or second end connection methods as described in API Recommended Practice 17A, Section 3. Flowline connectors may be either diverless or diver-assisted and may utilize guidelines/guideposts to provide guidance and alignment of the equipment during installation. Guidelineless systems are beyond the scope of this specification.

915.2 FLOWLINE CONNECTOR SUPPORT FRAME.

915.2a General — The flowline connector support frame provides a structural attachment to the subsea tree and/or subsea wellhead which will receive the flowline connector mechanism. The support frame may be attached to the subsea wellhead housing, the permanent guide base, the tree and/or tree frame, the template frame (if applicable), or other suitable structural member.

915.2b Design.

915.2b(1) Loads — The following loads shall be considered and documented by the manufacturers when designing the flowline connector support frame:

- Flowline pull-in, catenary, and/or drag forces during installation.
- Flowline alignment loads (rotational, lateral, and axial during installation).
- Flowline operational reaction loads due to residual stresses, flowline weight, thermal expansion/contraction and operational/environmental effects.
- Flowline reaction/alignment loads when the tree is removed for service.
- Overloads, such as snag loads, mudslides, etc.

915.2b(2) Dimensions — The flowline connector support frame should be designed to allow landing a BOP stack on the wellhead housing after the flowline connector support frame is installed.

915.2b(3) Functional Requirements — The flowline connector support frame shall be designed in accordance with Section 300 of this specification. It should react all loads imparted by the flowline and umbilical into a structural member to ensure that:

- Tree valves and/or tree piping are protected from flowline/umbilical loads which could damage these components.
- Alignment of critical mating components is provided and maintained during installation.
- Tree can be removed and replaced without damage to critical mating components.

915.3 FLOWLINE CONNECTORS.

915.3a General. The flowline connector and its associated running tools provide the means for joining the subsea flowline(s) and/or umbilical(s) to the subsea tree. In some cases, the flowline connector also provides means for disconnecting and removing the tree without retrieving the subsea flowline/umbilical to the surface.

Flowline connectors generally fall into three categories: 1) Manual connectors operated by divers or ROV's, 2) Hydraulic connectors with integral hydraulics similar to subsea wellhead connectors, 3) Mechanical connectors with the hydraulic actuators contained in a separate running tool.

915.3b Design. Flowline connectors shall have a rated working pressure equal to the rated working pressure of the tree. The design of flowline connectors shall be in accordance with Section 300 of this specification with the exception that the pressure testing shall comply with Section 600 of this specification for a connector mounted inboard of the first wing valve. For a connector mounted outboard of the first wing valve, pressure testing shall comply with an existing documented piping code such as ANSI/ASME B31.4, B31.8 or B31.3.

915.3b(1) Loads — The following loads shall be considered and documented by the manufacturer when designing the flowline connector and associated running tools:

- Flowline pull-in, catenary, and/or drag forces during installation.
- Flowline alignment loads (rotational, lateral, and axial) during installation.
- Flowline reaction loads due to residual stresses, flowline weight, thermal expansion/contraction and operational/environmental effects.
- Reactions from environmental loads on flowline connector running/retrieval and maintenance tools.
- Flowline reaction/alignment loads when the tree is pulled for service.
- Flowline/Umbilical overloads.
- Internal and external pressures (Operational and Hydrostatic/Gas Tests).

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

When actuated to the locked position, hydraulic flowline connectors shall remain self-locked without requiring hydraulic pressure to be maintained. Connectors should be designed to prevent loosening due to cyclic installation and/or operational loading.

915.3b(2) Dimensions — The dimensions of the flowline connectors flow passages should be compatible with the drift diameters of the flowlines.

If TFL service is specified, the TFL flow passage geometry shall meet the dimensional requirements of API Recommended Practice 17C.

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

The end connections used on the flowline connector (flanges, clamp hubs, or other types of connections) shall comply with Sections 901 through 906 of this specification. Preparations for welded end connections shall comply with Section 901.2 of this specification.

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

915.3b(3) Functional Requirements — The flowline connector and/or its associated running tool(s) should provide positioning and alignment of mating components such that connection can be accomplished without damage to sealing components or structural connection devices. Seals and sealing surfaces should be protected during flowline installation operations.

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

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

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

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

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

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

915.4 MATERIALS. Flowline connector support frames may be of welded construction using common structural steels that conform to Section 400 of this specification.

The pressure containing components of the flowline connector shall comply with Section 400 of this specification. Other structural steel components of the flowline connector shall comply with Section 300 and 600 of this specification.

915.5 WELDING. Welding requirements shall conform to Section 500 of this specification.

915.6 TESTING.

915.6a General — This section deals with testing of the flowline connector system which includes the flowline connector support frame, the flowline connector, the flow loops, and associated running/retrieval and maintenance tools. Testing requirements of the flowline(s) and umbilical(s) are beyond the scope of this specification.

915.6b Performance Verification Testing — Tests shall be conducted to verify the structural and pressure integrity of the flowline connector system under the rated loads specified by the manufacturer in accordance with Section 307 of this specification. Such tests shall also take into consideration:

- Simulated operation of all running/retrieval tools under loads typical of those expected during actual field installations.
- Simulated pull-in or catenary flowline loads (as applicable) during flowline installation and connection.
- Removal and replacement of primary seals for flowline connectors for remotely replaceable seals.
- Functional tests of required running/retrieval and maintenance tools.
- Maximum specified misalignment.

The manufacturer shall document successful completion of the above tests.

915.6c Factory Acceptance Testing.

Structural Components — All mating structural components shall be tested per the manufacturer's written specification for fit and function using actual mating equipment or test fixtures.

Pressure Containing Components — For flowline connectors mounted outboard of the first wing valve, all pressure containing components shall be hydrostatically tested in accordance with the specified flowline code. For flowline connectors mounted inboard of the first wing valve, hydrostatic tests shall be conducted in accordance with Section 600 of this specification.

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

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

After final assembly, the connector shall be tested for proper operation and interface per the manufacturer's written specification using actual mating equipment or an appropriate test fixture. Hydraulic circuits (if applicable) shall be subjected to a hydrostatic test per the requirements of Section 908.5b(3)(b) of this specification.

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

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

915.6d In-Situ Testing — In-Situ testing is beyond the scope of this specification. However, if In-Situ testing of flowlines is required at pressures above the tree rated working pressure, a test isolation valve with a higher working pressure than the tree may be required.

915.7 MARKING. Marking shall comply with Section 700 of this specification.

915.8 STORING AND SHIPPING. Storing and shipping shall comply with Section 800 of this specification.

916 CONTROL PACKAGE (POD) RUNNING/RETRIEVAL AND TESTING TOOLS.

916.1 GENERAL. The Control Package Running/Retrieval and Testing Tools are used to install, remove, and test the subsea components of the production control system. The design of these tools is dependent upon the type of control system utilized and the configuration of the subsea hardware which may include a control pod and hydraulic accumulator system (Refer to API Recommended Practice 17A Section 4.4.3).

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

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

916.2 DESIGN. The control package (POD) running/retrieval and testing tool shall comply with Section 300 of this specification.

916.2a Operating Parameters. The manufacturer shall document the operating criteria for which the control package (POD) running/retrieval and testing tools are designed. Specific operating criteria for the control package running/retrieval and testing tools shall be derived in the same manner specified in Section 912.2a of this specification.

916.2b Running Tool Interface. The manufacturer shall document the maximum combined loads at which the running tool can remain connected without damage to the extent that any other performance requirement is not met. The running tool shall be designed for emergency release at running string tensions and departure angles as specified and documented by the manufacturer.

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

916.2c Control Package Guideframe. If used, guideframes on the control package and/or running tool shall be designed to provide for the alignment of mating components during installation and removal in accordance with the manufacturer's written specification.

916.3 MATERIALS. Materials selection shall conform to Section 400 of this specification.

916.4 WELDING. Welding requirements shall conform to Section 500 of this specification.

916.5 TESTING. Testing requirements shall conform to Section 600 of this specification.

916.6 MARKING. Component marking shall conform to the requirements of Section 700 of this specification.

916.7 STORING AND SHIPPING. Storing and shipping shall conform to the requirements of Section 800 of this specification.

917 FLOWLINE CONNECTOR SUPPORT FRAME RUNNING/RETRIEVING TOOLS AND RELATED SYSTEM INTERFACES.

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

917.2 DESIGN. The design of these running tools shall comply with Section 300 of this specification.

917.2a Operating Criteria. The manufacturer shall document the operating criteria for which the flowline connector support from running/retrievel tools and related system interfaces are designed. Specific operating criteria for the flowline connector support frame running tool shall be derived in the same manner specified in Section 912.2a of this specification.

917.2b Loads and Component Strength. Design loads of the flowline connector support frame running tool shall be determined in the manner specified in Section 912.2b of this specification.

917.2c Running Tool Interfaces. The flowline connector support frame running tool shall be capable of connection, function and disconnection at the maximum combined loads, as specified by the manufacturer.

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

917.2d Guidance and Alignment. If used, guidance structures shall be designed to provide for alignment of mating components during installation and removal in accordance to the manufacturer's written specification.

917.2e Remote Intervention Equipment. Remote intervention fixtures shall be designed in accordance with requirements of Section 921 of this specification.

917.3 MATERIALS. Materials shall conform to Section 400 of this specification.

917.4 WELDING. Welding requirements shall conform to Section 500 of this specification.

917.5 TESTING. Test of flowline connector support frame running tool shall conform with Sections 300 and 600 of this specification.

917.6 MARKING. The flowline connector support frame running tool shall be marked to conform with Section 700 of this specification.

917.7 STORING AND SHIPPING. The flowline connector support frame running tool shall be stored and shipped in accordance with Section 800 of this specification.

918 TREE-MOUNTED HYDRAULIC CONTROL INTERFACES

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

918.2 DESIGN.

918.2a Pipe/Tubing/Hoses. Allowable stresses in pipe/tubing shall be in conformance with ANSI B31.3. Hose design shall conform to an existing documented industry standard such as SAE Standard J517. Design shall take into account:

- Allowable stresses at working pressure
- Allowable stresses at test pressure
- External loading
- Collapse
- Manufacturing tolerances
- Fluid compatibility
- Flow rate
- Corrosion/erosion
- Temperature range

918.2b All pipe/tubing/hose shall be 1/4" (6 mm) nominal diameter, or larger.

918.2c All pipe/tubing/hose shall be within the envelope defined by the guideframes of the tree, running/retrieving tool, or the flowline base.

918.2d All pipe/tubing/hose should be supported and protected to minimize damage during testing, installation/retrieval, and normal operations of the subsea tree.

918.2e End Fittings, Connectors, Connector Plates. End fittings and connectors shall meet or exceed requirements of the existing piping code used for the piping/tubing/hose design in Section 918.2a of this specification.

The connector plate/junction plate assembly shall be designed to withstand rated working pressure applied simultaneously in every control path without deforming to the extent that any other performance requirement is not met in accordance with the manufacturer's written specification. In addition, when non-pressure balanced control stabs are used, the manufacturer shall determine and document the rated water depth at which connector plate/junction plate can decouple the control stabs without deformation damage to the plate assemblies. The manufacturer shall determine and document the force required for decoupling at rated water depth.

Proprietary connector plate/junction plate designs shall meet the test requirements set forth in Section 918.4 of this specification.

918.2f Control Line Stabs. As a minimum, control line stabs for the SCSSV, Production Master Valve(s), Production Wing Valve, and an Annulus Valve shall be designed so as not to trap pressure when the control stabs are separated. The control stabs should be designed to minimize seawater ingress when disconnected. In addition to the internal working pressure, the control stabs shall be designed to withstand external hydrostatic pressure at manufacturer's rated water depth.

918.3 MATERIALS.

918.3a Pipe/tubing and end fittings, connectors and connector plates shall be made of materials which conform to Section 400 of this specification.

Pipe/tubing/hoses which are not isolated from wellbore fluids by either at least two barriers/seals or other appropriate means, shall be designed and materials selected for exposure to wellbore fluids and pressures.

918.3b Seal materials used in the end fittings and connectors shall conform to Section 400 of this specification.

918.4 TESTING.

918.4a Pipe/tubing shall be of a design which has been performance verification tested in conformance to ANSI B31.3. Hoses shall be of a design which has been performance verification tests in conformance to SAE J343. Performance verification testing for hoses shall be repeated for hose designs whose verification test are more than five years old.

Testing of assembled pipe/tubing/hose and end fittings, connectors, and connector plates shall conform to Section 600 of this specification, except that the test pressure shall not exceed the test pressure of the lowest pressure rated component in the system.

918.4b The connector plate/junction plate assembly shall be tested with rated working pressure applied simultaneously in every control path in accordance with the manufacturer's written specification.

918.5 MARKING.

918.5a Component marking shall conform to applicable requirements set forth in Section 700 of this specification.

918.5b Each connector plate shall be permanently marked with the following minimum information:

- Its part number and the part number of the connector plate it is designed to mate with, for example:

  "(Part number) TO MATE WITH (part number of mating plate)"

- Path designation numbers or letters identifying each path/connector in the connector plate assembly (Hoses and Tubing should be marked accordingly).
- Rated operating pressures of each path passing through the connector plate assembly, for example:

  6 X 3000 PSI (20,7 MPa) - PATHS 1 - 6

  4 X 1500 PSI (10,3 MPa) - PATHS 7, 8, 11, 12

  2 X 5000 PSI (34,5 MPa) - PATHS 9, 10

918.6 STORING AND SHIPPING. Storing and shipping shall conform to Section 800 of this specification.

919 SUBSEA CHOKES AND ACTUATORS.

919.1 GENERAL. This section covers subsea chokes, actuators, and their assemblies used in subsea applications. It provides requirements for the choke/actuator assembly performance standards, sizing, design, materials, testing, marking, storage and shipping. Subsea choke applications are production, gas lift, and injection. Chokes are a special kind of control valve designed to control flow or pressure and are not intended to be used as shutoff valves.

Subsea chokes are considered high wear items and therefore allowances for choke maintenance should be considered. Subsea chokes may be designed for changing flow bean or trim by divers or ROV/running tools. Placement of the choke should allow adequate spacing for retrieval, and diver/ROV override operations.

919.2 SUBSEA CHOKES.

919.2a General.

919.2a(1) Adjustable Chokes. Adjustable chokes have an externally controlled variable-area orifice trim and may be coupled with an orifice area indicating mechanism.

919.2a(2) Positive Chokes. Positive chokes accommodate replaceable parts having a fixed orifice dimension, commonly known as flow beans.

919.2a(3) Orifice Configuration. "Orifice Configuration" for chokes, sometimes referred to as "trim," in control valve terminology, describes the internal components which determine flow area through the choke. A variety of orifice configurations are available for chokes. Five of the most common adjustable orifice configurations are: rotating disc, needle and seat, plug and cage, sliding sleeve and seat, and multistage. Examples of orifice configurations are shown in Figure 919.1. Optimum orifice configuration is selected on the basis of operating pressures, temperatures and flow media.

919.2a(4) Choke Capacity. The manufacturer shall document flow rate based on maximum orifice, pressure, temperature and fluid media.

The choke orifice diameter should be sized for anticipated or actual production flow rate and fluid conditions (pressures and temperature). The information shown in Appendix A for Purchasing Guidelines should be supplied to the choke manufacturer for sizing of the choke.

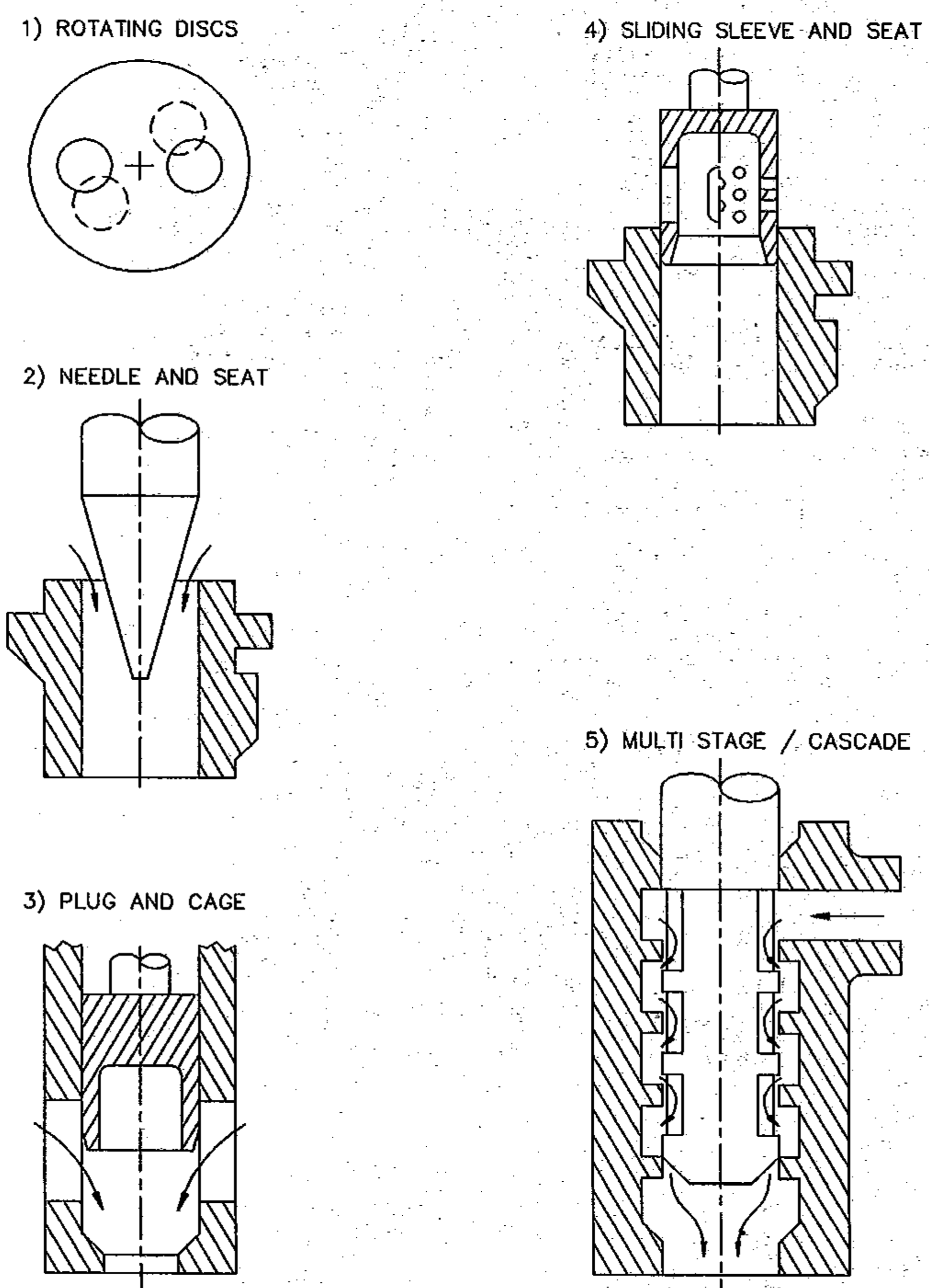
919.2b Design. Subsea chokes shall be designed in accordance with the general design requirements of Section 300 of this specification and Section 909.2 of API Specification 6A, as required for PR2.

Manufacturers shall document the design and operating parameters of the choke as listed in Table 919.1 of this specification.

TABLE 919.1
DESIGN AND OPERATING PARAMETERS OF SUBSEA CHOKES

- Manufacturer (Name and Location)
- Model Number
- Maximum Pressure Rating
- Maximum Orifice Size
- Temperature Rating
  - Maximum
  - Minimum
- API PSL Level
- API Material Class
- Type of Choke
  - Positive (Fixed, Insert Type)
  - Adjustable Choke with Handwheel
  - Adjustable Choke Prep. for Manual Actuator
  - Adjustable Choke Prep. for Hydraulic Actuator
- End Connections
  - Size and Pressure Rating (API)
  - API Ring Gasket Size (If Applicable)
- Type of Operation
  - ROV
  - Diver Assist
  - Size of Socket or Hex (If Applicable)
  - Handwheel Diameter
- External Pressure Rating (Maximum) or Water Depth
- Maximum Flow Rate

FIGURE 919.1


1) ROTATING DISCS
2) NEEDLE AND SEAT
3) PLUG AND CAGE
4) SLIDING SLEEVE AND SEAT
5) MULTI STAGE / CASCADE

919.2b(1) Pressure Rating. Subsea chokes with maximum rated working pressures of 5,000, 10,000, or 15,000 psi (34,5; 69,0 or 103,5 MPa) are covered by this specification.

For chokes having end connections with different pressure ratings, the rating of lowest rated pressure containing part shall be the rating of the subsea choke. The rated working pressure of the subsea choke shall be equal to or greater than the rated working pressure of the subsea tree.

919.2b(2) Temperature Rating. All pressure containing components of subsea chokes shall be designed for the temperature ratings specified in Section 302.2 of this specification. For subsea chokes, the maximum temperature rating is based on the highest temperature of the fluid which may flow through the choke. Subsea chokes shall have a maximum temperature rating equal to or greater than the tree. The minimum temperature rating of subsea chokes shall be in accordance with the manufacturer's written specifications.

919.2b(3) End Connections. End connections for chokes shall be as specified in Sections 901 to 906 of this specification.

919.2b(4) Vent Requirements. Subsea chokes shall be designed to allow trapped pressure to be vented prior to releasing the body-to-bonnet connector on adjustable chokes and the body-to-cap connector on positive chokes.

919.2b(5) External Pressure Requirements. Subsea chokes shall be designed to withstand external hydrostatic pressure at the manufacturer's maximum rated water depth.

919.2c Choke Testing.

919.2c(1) Performance Verification Test. Design verification testing of subsea chokes shall comply with Section 307 of this specification.

919.2c(2) Factory Acceptance Test. Hydrostatic testing of subsea chokes shall be in accordance with Section 600 of this specification. For Factory Acceptance Test Data Sheet for subsea choke, refer to Table 919.2.

919.3 SUBSEA CHOKE ACTUATORS.

919.3a General. This section covers manual and hydraulic actuators for subsea applications. Electric power or motor driven actuators, position indicators, and control feedback equipment are beyond the scope of this specification.

919.3b Design.

919.3b(1) General.

(a) The design of subsea choke actuators shall comply with Section 300 of this specification.

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

(c) Subsea choke actuators shall conform to the temperature ratings of Section 302.2 of this specification.

919.3b(2) Manual Actuators.

(a) The design of the manual actuation mechanism shall take into consideration ease of operation, adaptability of diver tools, atmospheric diving systems and/or ROV's for operations.

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

(c) Rotary operated subsea chokes shall be turned in the counterclockwise direction to open and the clockwise direction to close as viewed from the end of the stem.

(d) Intervention fixtures for manual subsea choke actuators shall comply with Section 921 of this specification.

(e) Manufacturer shall document design and operating parameters of subsea choke manual actuators as listed in Table 919.3.

919.3b(3) Hydraulic Actuators.

(a) Hydraulic actuators shall be designed for a nominal hydraulic working pressure rating of either 1500 or 3000 psi (10,3 or 20,7 MPa).

(b) Opening and closing force and/or torque of hydraulic actuators shall operate the subsea choke when the choke is at the most severe design operating conditions without exceeding 90% of the nominal hydraulic operating pressure.

(c) Hydraulic actuators shall be designed for a specific choke or specific group of chokes with consideration of the operating characteristics and maximum rated working conditions (temperature range, pressure, depth) of those chokes.

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

(e) The design of the hydraulic actuators shall consider the effects of rated working pressure within the choke, external hydrostatic pressure at the manufacturer's maximum depth rating and maximum hydraulic operating pressure.

(f) Liquid filled hydraulic actuators shall be designed with volume compensation to accommodate the temperature range specified.

(g) Manufacturer shall document design and operating parameters of subsea choke hydraulic actuators as listed in Table 919.4.

TABLE 919.2
FACTORY ACCEPTANCE TEST DATA SHEET
SUBSEA CHOKE

A. CHOKE DATA:

Manufacturer ______________________

Model No. ____________ Part No. ____________

Serial No. ____________ Orifice Size ____________

Working Pressure ____________ Test Pressure ____________

Temp. Rating ____________ PSL Level ____________

B. HYDROSTATIC TEST:

Test Pressure ____________

First Holding Period Beginning ____________

Completion ____________

Total Test Time (Minutes) ____________

Second Holding Period Beginning ____________

Completion ____________

Total Test Time (Minutes) ____________

Performed By ____________ Date ____________

C. OPERATIONAL TEST OF SUBSEA CHOKE WITH HANDWHEEL:

Cycle Number	Pressure in Choke PSI	Remarks
Test #1	15 PSI Atmospheric	
1		
2		
3		
Test #2	Working Pressure of Choke	
1		
2		
3		
4		
5		

Test Performed By ____________ Date ____________

TABLE 919.3
DESIGN AND OPERATING PARAMETERS OF MANUAL ACTUATORS FOR SUBSEA CHOKES

- Choke Manufacturer (Name and Location)
- Choke Model Number
- Operating Torque (Input)
- Maximum Rated Torque Capacity
- Type & Size of Interface (ROV) for Manual Operation
- API PSL Level
- API Material Class
- API Temperature Rating
- Number of Turns to Operate Choke

TABLE 919.4
DESIGN AND OPERATING PARAMETERS OF HYDRAULIC ACTUATORS FOR SUBSEA CHOKES

- Choke Manufacturer (Name and Location)
- Choke Model Number
- Design Type (Ratchet, Stepping, Rotary, Linear Actuators)
- Maximum Output Torque Capacity
- API PSL Level
- API Material Class
- API Temperature Rating
- Full Stroke Definition
- Hydraulic Cylinder(s)
  - Number of Cylinders
  - Volume
  - Pressure Rating
- Type of Local Position Indicator (If Any) (Percent or 64th)
- Manual Override (If Supplied)
  - ROV Assist or Diver Assist
  - Maximum Input Torque Capacity
  - Direction to Open
  - Hex or Socket Size and Length
  - Number of Turns to Open or Close the Choke
- Water Depth Rating
- Type of Volume Compensation Device (If Any)

919.3b(4) Documentation. Actuator manufacturer shall document the design and operating parameters given in Tables 919.3 and 919.4 for manual and hydraulic actuators, respectively.

Actuator manufacturer shall prepare an Installation and Service Manual.

919.3c Actuator Testing.

919.3c(1) Performance Verification Test Procedure. Subsea choke actuator performance verification test procedure shall be in accordance with Section 307 of this specification.

919.3c(2) Factory Acceptance Test.

(a) Subsea choke actuators shall be factory acceptance tested in accordance with API Specification 6A, Section 916.5, except for backseating. All test data shall be recorded on a data sheet similar to that indicated in Table 919.5 of this specification.

(b) When subsea choke actuators are shipped separately, the actuators shall be assembled with a test fixture that meets the specified choke operating parameters, and factory acceptance tested per Section 919.4c of the specification.

919.4 CHOKE AND ACTUATOR ASSEMBLY.

919.4a Design. Subsea chokes shall be assembled with an actuator designed to operate that choke.

Subsea choke and actuator assembly designated as "fail in the last position" shall be designed and fabricated to prevent backdriving by the choke at full working pressure, at the loss of hydraulic actuator pressure.

Manual choke actuators shall prevent backdriving under all operating conditions.

Means shall be provided to prevent wellbore fluid from overpressuring the actuator.

919.4b Choke/Actuator Assembly Performance Verification Testing. The subsea choke and actuator assembly shall be tested in accordance with Section 307 of this specification.

919.4c Choke/Actuator Assembly Factory Acceptance Test. The subsea choke and actuator assembly shall be tested to demonstrate proper assembly and operation in addition to test specified in Sections 919.2c(2) and 919.3c(2). All test data shall be recorded on a data sheet similar to that indicated in Table 919.6. The test data sheet shall be signed and dated by the person(s) performing the test(s).

919.4c(1) Actuator Cylinder Seal Test. Subsea choke actuators shall be tested per API Specification 6A, Section 916.5b(1).

919.4c(2) Operational Test. Each subsea choke and actuator assembly shall be tested for proper operation in accordance with the manufacturer's written specification. This shall be accomplished by actuating the subsea choke from the fully closed position to the fully open position a minimum of three times with the choke body at atmospheric pressure and a minimum of five times with the choke body at rated working pressure.

The operational test of each subsea choke and actuator shall include recording the data requested in Table 919.6 Section "A," and shall include the recording of the test data specified in Table 919.6 Section "B" and/or Section "C".

For assemblies with hydraulic operators, the actuation of the choke shall be accomplished with an

TABLE 919.5
FACTORY ACCEPTANCE TEST DATA SHEET
HYDRAULIC ACTUATOR

A. <u>ACTUATOR DATA:</u>

Manufacturer ______________________________

Model No. ________________ Part No. ________________

Serial No. ________________ Size ________________

Hydraulic Pressure Rating ____________

Temp. Rating ________________ PSL Level ________________

Actuator Separate ☐ <u>or</u> with Choke ☐

B. <u>ACTUATOR CYLINDER SEAL TEST (HYDROSTATIC TEST):</u>

Test Pressure ________________

Cylinder 1

Holding Period Beginning ________________

Completion ________________

Total Test Time (Minutes) ________________

Cylinder 2

Holding Period Beginning ________________

Completion ________________

Total Test Time (Minutes) ________________

Performed By ________________ Date ________________

C. <u>PERFORMANCE TEST FOR ACTUATORS SHIPPED SEPARATELY:</u>

Refer to Table 919.6.

TABLE 919.6
FACTORY ACCEPTANCE TEST
SUBSEA CHOKE WITH HYDRAULIC OPERATOR

SECTION "B" OPERATIONAL TEST (CHOKE WITH HYDRAULIC OPERATOR)

TEST NO.	CYCLE NO.	CHOKE PRESSURE	HYDRAULIC PRESSURE REQUIRED TO:		VERIFICATION THAT THE CHOKE OPERATED SMOOTHLY AND WITHOUT BACKDRIVING					
			CLOSE CHOKE	OPEN CHOKE	DURING OPENING YES	NO	WITNESS	DURING CLOSING YES	NO	WITNESS
1	1	ATMOS-PHERIC								
	2	ATMOS-PHERIC								
	3	ATMOS-PHERIC								
2	1	WORKING PRESSURE								
	2	WORKING PRESSURE								
	3	WORKING PRESSURE								
	4	WORKING PRESSURE								
	5	WORKING PRESSURE								

TABLE 919.6
FACTORY ACCEPTANCE TEST
SUBSEA CHOKE WITH MECHANICAL ACTUATOR
AND/OR HYDRAULIC OPERATOR WITH MECHANICAL OVERRIDE

SECTION "C" OPERATIONAL TEST — CHOKE AND MANUAL OPERATOR
OR CHOKE AND HYDRAULIC OPERATOR WITH MANUAL OVERRIDE

TEST NO.	CYCLE NO.	CHOKE PRESSURE	VERIFICATION THAT THE CHOKE OPERATED SMOOTHLY AND WITHOUT BACKDRIVING WITHIN THE MANUFACTURERS SPECIFIED TORQUE LIMIT					
			DURING OPENING YES	NO	WITNESS	DURING CLOSING YES	NO	WITNESS
1	1	ATMOSPHERIC PRESSURE						
	2	ATMOSPHERIC PRESSURE						
	3	ATMOSPHERIC PRESSURE						
2	1	WORKING PRESSURE						
	2	WORKING PRESSURE						
	3	WORKING PRESSURE						
	4	WORKING PRESSURE						
	5	WORKING PRESSURE						

TABLE 919.7
MARKING DATA SHEET FOR SUBESA CHOKES

Marking	Location
Manufacturer's Name and/or Trademark	Body or Nameplate
Model Number and Type	Body or Nameplate
Maximum Working Pressure Rating	Body or Nameplate
Serial or Identification Number Unique to the Particular Choke	Body or Nameplate
Maximum Orifice Diameter (64th)	Body or Nameplate
Direction of Flow	Body
API Requirements: • Letter 17D • PSL Level • Performance Level • Material Class • Temperature Rating • Date (Month/Year)	
Flange Size, Pressure and Ring Joint Designation	Flange(s) Periphery
Material & Hardness	Body and Bonnet (Cap)
Part Number	Body or Nameplate

TABLE 919.8
MARKING DATA SHEET FOR MANUAL SUBSEA CHOKE ACTUATORS

Marking	Location
Manufacturer	Body or Nameplate
Model Number	Boby or Nameplate
Input Torque (Maximum) Capacity	Nameplate
Maximum Torque Capacity	Nameplate
Number of Turns to Open	Nameplate
Date (Month/Year)	Nameplate
Serial Number (If Required)	Nameplate
Part Number	Nameplate
API Requirements • PSL Level • Temperature Range • Letter 17D • Date (Month/Year)	Nameplate

TABLE 919.9
MARKING DATA SHEET FOR SUBSEA HYDRAULIC CHOKE ACTUATORS

Marking	Location
Manufacturer	Nameplate
Model Number	Nameplate
Maximum Operating Hydraulic Pressure — PSI	Nameplate and Cylinder
Input Torque Rating (Maximum) — Ft. Lbs.	Nameplate
Maximum Output Torque — Ft. Lbs.	Nameplate
Number of Steps to Open	Nameplate
API Requirements • PSL Level • Temperature Range • Letter 17D • Date (Month/Year)	Nameplate
Serial Number (If Required)	Nameplate
Part Number	Nameplate
Manual Override Direction to Open	Nameplate

TABLE 919.10
MARKING FOR SUBSEA CHOKE AND ACTUATOR ASSEMBLY

Marking	Application on Actuator
1. Assembler's name or trademark	Nameplate
2. The letter 17D	Nameplate
3. Assembly serial or identification number	Nameplate
4. Rated water depth	Nameplate

actuator pressure equal to or less than 90% of the rated operating pressure, and the following information shall be recorded on a data sheet such as illustrated by Table 919.6 Part "B".

- Pressure inside choke body.
- Actuator pressure required to close choke.
- Actuator pressure required to open choke.
- Verification that the choke operated smoothly and without backdriving.

For assemblies with manual operators, the following information shall be recorded on a data sheet such as illustrated by Table 919.6 Section "C".

- Pressure inside choke body.
- Verification that the choke operated smoothly and without backdriving. Within the manufacturer's specified torque limit.

For assemblies with hydraulic operators and manual overrides, both sets of tests outlined above shall be accomplished and the results recorded on a data sheet such as illustrated by Table 919.6 Section "B" and Section "C".

919.5 MATERIALS. Both subsea chokes and subsea choke actuators shall be made of materials which meet the applicable requirements of Section 400, and the requirements of API Specification 6A, Section 909.4 and 916.4.

919.6 WELDING. Welding of pressure containing components shall be performed per the requirements of Section 500 of this specification. Welding of pressure controlling ("Trim") components shall comply with the manufacturer's written specifications.

919.7 MARKING. Marking shall be per Section 700 of this specification. In addition, subsea chokes, manual actuators, hydraulic actuators, and choke/actuator assemblies shall be marked in accordance with Tables 919.7, 919.8, 919.9, and 919.10 respectively.

919.8 STORING AND SHIPPING. Storing and shipping shall conform to Section 800 of this specification.

920 MISCELLANEOUS EQUIPMENT.

920.1 GENERAL. A variety of miscellaneous tools and accessories are used with subsea wellhead and subsea completion equipment. This subsection identifies requirements for some common tools. These tools and other miscellaneous equipment not specifically listed here shall be designed and manufactured in accordance with the structural requirements, stress limitations and documentation requirements of Section 300 of this specification.

920.2 DESIGN.

920.2a General.

920.2a(1) Loads. As a minimum, the following loads shall, where applicable, be considered when designing miscellaneous equipment:

- Suspended weight
- Control pressure
- Well pressure
- Hydrostatic pressure
- Handling loads
- Impact

920.2a(2) Operating Pressure. Tools operated by hydraulic pressure shall be rated in accordance with the pressure ratings specified by the manufacturer.

920.2a(3) Rated Working Pressure. Pressure containing and pressure controlling tools subject to well pressures shall be rated according to Section 300 of this specification.

920.2b Remote Guideline Establishment and Re-establishment Tools. Guideline establishment/re-establishment tools are used to attach cables to guide posts of subsea completion structures. Any such tool which uses the relative guide post positions shall be designed based on the spacing described in Section 1001.3b(2) of this specification.

920.2c Test Stands and Fixtures. Test stands and fixtures are used at the point of assembly or installation to verify the functional operation and load and pressure capacity of the installed equipment listed in Section 900 of this specification. Test stands and fixtures used only at the manufacturer's facilities are outside the scope of this specification. Where test equipment is used to simulate a mating component for testing the assembly of interest it shall be made to the same dimensions and tolerances at all interfaces as the simulated component. Design of test stands and fixtures shall consider assembly and handling loads as well as test loads.

920.3 MATERIALS. Materials shall be selected to meet the requirements of Sections 300 and 400 of this specification if subjected to well fluid contact. Selection of other materials shall consider encountered fluids and galvanic compatibility, as well as mechanical properties.

920.4 WELDING. Welding requirements shall conform to Section 500 of this specification.

920.5 TESTING. All components subject to pressure shall be tested to one and one-half times their maximum rated working pressure unless a different test pressure is required elsewhere in this specification. The test procedure shall conform to Section 600 of this specification. Fit and functional testing shall be performed per the manufacturer's written specification for any tool which has an interface with equipment which is to be installed subsea.

920.6 MARKING. Tools shall be permanently marked following the methods and requirements of Section 700 of this specification. In addition, all tools which are not a permanent part of a subsea assembly shall be marked with the date of manufacture, applicable load ratings and part number.

920.7 STORING AND SHIPPING. Storing and shipping of miscellaneous equipment shall meet the requirements of Section 800 of this specification.

921 INTERVENTION FIXTURES.

921.1 GENERAL. This section sets forth specifications and standards for design, manufacturing, and testing of intervention fixtures fitted to subsea well equipment to facilitate support by divers, remotely operated vehicles, and atmospheric diving systems. Intervention tools and intervention systems are not covered by this specification.

Candidate configurations for potential standardization of generic types of intervention fixtures are given in Appendix C of this specification.

921.2 DESIGN.

921.2a General Performance/Service Requirements.

921.2a(1) Design Requirements. Intervention fixtures shall be designed in accordance with Section 300 of this specification, considering all loads specified in this section.

Maximum allowable column buckling load shall not exceed 1/2 critical buckling load.

921.2a(2) Alignment Requirements. Where applicable, intervention fixtures shall be designed for engagement by a mating intervention tool at an initial axial misalignment angle of at least 5 degrees without binding or damage.

921.2a(3) Fixture Functions. Intervention fixtures may be designed for a single function (i.e., grasping) or for multiple functions (i.e., docking and rotary actuation).

921.2a(4) Accessibility. Intervention fixtures should be fitted to subsea well equipment in a manner that does not interfere with other intervention equipment or subsea well functions.

921.2a(5) Fixture Identification/Markings. Intervention fixtures shall be clearly marked by use of painted, cutout or embossed characters (i.e., letters, numbers, or symbols).

Painted characters should be considered temporary and should not be used for applications requiring readability longer than three months.

Permanent markings shall be presented in one or more of the following options:

— Characters cut out of a 1/4-inch (6 mm) or thicker plate or base.

— Characters having at least 1/4-inch (6 mm) thickness embossed on a plate or base.

— Characters incorporated into a plaque or tablet specially designed for long life, subsea visual marking per the manufacturer's written specification.

Where practicable, minimum character size should be 4-inch (100 mm) high with a 1/2-inch (12 mm) minimum line width.

Plates or bases for cutout and embossed characters should be painted a nonreflective light color. Embossed characters should be painted a nonreflective black.

921.2a(6) Candidate API Standard Intervention Fixtures. Candidate intervention fixtures are included in Appendix C of this specification.

Design details of candidate API Standard intervention fixtures are included in Appendix C of this specification.

Intervention fixtures other than those defined in Appendix C may be utilized as long as they are designed, manufactured and tested in accordance with the requirements set forth in this specification.

921.2b Grasping Intervention Fixtures.

921.2b(1) Description. Grasping intervention fixtures are fitted to subsea well equipment to provide a standard interface for an Intervention System. Grasping may be by a diver's hand or a manipulator arm having a parallel or pincer jaw.

921.2b(2) Performance/Service Requirements. Grasping intervention fixtures shall be designed to withstand a minimum of:

- A force of 500 pounds (2200 Newtons) applied from any direction.
- A gripping force of 500 pounds (2200 Newtons).

921.2c Docking Intervention Fixtures.

921.2c(1) Description. Docking intervention fixtures are fitted to subsea equipment to allow an intervention system to attach itself in a defined position.

921.2c(2) Performance/Service Requirements. Docking intervention fixtures (when fully engaged) shall be designed to withstand the larger stresses resulting from either a force of 500 pounds (2200 Newtons) applied in any direction, or a 3000 ft-lbs (4050 N-m) moment applied in any direction.

Docking intervention fixtures should have no moving parts and should be designed to preclude trapping the Intervention System.

921.2d Landing Intervention Fixtures.

921.2d(1) Description. Landing intervention fixtures are designated support platforms or work space to allow an Intervention System to sit, stand, or otherwise position itself on a flat horizontal surface to carry out Intervention Tasks.

921.2d(2) Performance/Service Requirements. Minimum landing intervention fixture size, load, and clearance requirements shall be as defined on Table 921.1. Additional clearance should be provided for sled, work packages, or other appurtenances carried by the intervention system. There should be clear access to the landing fixture and there should be no overhang which interferes with vertical access.

The landing intervention fixture shall be designed to support the weight of the defined intervention system in air during dry systems tests and to support tool reaction forces.

Landing intervention fixtures should be of open grid construction to minimize buildup of debris and should have no obstructions which could interfere with landing a flat-bottomed intervention system. Large landing intervention fixtures may require hinges or other special features to facilitate rig handling and installation/retrieval operations.

Load ratings of landing intervention fixtures shall be clearly marked in accordance with Section 700 of this specification.

921.2e Linear Actuator Intervention Fixtures.

921.2e(1) Description. Linear actuator intervention fixtures shall be designed to provide means for a linear actuator intervention tool to push or pull a rod or other linkage to operate a valve, connector device, or other subsea well equipment apparatus.

921.2e(2) Performance/Service Requirements. Linear actuator intervention fixtures and associated structure shall be designed in accordance with Section 921.2a(1) of this specification to transmit and resist axial loads for selected load classifications in accordance with Table 921.2 and Section 921.2a(2) of this specification for alignment requirements.

TABLE 921.2
LINEAR ACTUATOR INTERVENTION FIXTURE LOAD CLASSIFICATIONS

CLASSIFICATION	MAXIMUM DESIGN WORKING LOAD (LBS) (NEWTONS)
1	100 (445)
2	1,000 (4450)
3	3,000 (13350)
4	5,000 (22250)
5	8,000 (35600)
6	22,000 (97900)
7	75,000 (333750)
8	240,000 (1068000)

TABLE 921.1
LANDING INTERVENTION FIXTURE SIZE, LOAD, AND CLEARANCE REQUIREMENTS OF INTERVENTION SYSTEMS

APPLICATION	LANDING FIXTURE DIMENSIONS (IN) (mm) LENGTH	WIDTH	LOAD (LBS-AIR) (Newtons)	REQUIRED CLEAR VOLUME ABOVE FIXTURE (IN) (mm) LENGTH	WIDTH	HEIGHT
Diver	24 (610)	42 (1065)	1,000 (4450)	60 (1525)	60 (1525)	80 (2035)
ROV - Inspection[(2)]	48[(2)] (1220)	36 (915)	1,000 (4450)	120 (3050)	56 (1425)	48 (1220)
ROV - Limited Work[(2)]	72[(2)] (1830)	60 (1525)	5,000 (22750)	144 (3660)	96 (2440)	120 (3000)
ROV - Heavy Work[(2)]	108[(2)] (2745)	72 (1830)	9,000 (40050)	180 (4510)	108 (2745)	138 (3505)

NOTES:

(1) Typical Dimensions - (L x W x H)

- Inspection ROV - (48" x 22" x 22") (1770 x 560 x 560 mm)
- Limited work ROV - (78" x 36" x 36") (1980 x 915 x 915 mm)
- Heavy work ROV - (86" x 70" x 95") (2185 x 1780 x 2415 mm)

(2) ROV length may overhang fixture length; however, ROV width shall not overhang fixture width.

921.2e(3) Design Details. Design details of Candidate API Standard Linear Actuator Intervention Fixtures are included in Appendix C of this specification.

921.2f Rotary Actuator Intervention Fixtures.

921.2f(1) Description. Rotary Actuator Intervention Fixtures shall be designed to provide a means for a Rotary Actuator Intervention Tool to apply torque to a rod or other linkage to operate a valve, connecting device, or other rotationally operated subsea well equipment apparatus.

921.2f(2) Performance/Service Requirements. Rotary Actuator Intervention Fixtures and associated structure shall be designed in accordance with Section 921.2a(1) of this specification to transmit and resist torque for selected torque classifications in accordance with Table 921.3 of this specification.

TABLE 921.3
ROTARY ACTUATOR INTERVENTION FIXTURE CLASSIFICATION

CLASSIFICATION	MAXIMUM DESIGN WORKING TORQUE (FT-LB) (N-M)
1	50 (70)
2	200 (270)
3	1,000 (1350)
4	2,000 (2700)
5	5,000 (6750)
6	10,000 (13500)
7	25,000 (33750)

921.2g Fluid Coupling Intervention Fixtures.

921.2g(1) Description. Fluid coupling intervention fixtures are fitted onto subsea equipment to facilitate access to fluid piping circuits.

921.2g(2) Performance/Service Requirements. Fluid coupling intervention fixtures shall not have seals. All seal elements shall be part of the intervention tool.

Corrosion resistant materials shall be used for fluid coupling seal bores.

A removable fluid coupling intervention fixture protector should be provided to protect seal surfaces from damage, debris, or marine growth. If the protector is used to contain pressure, design of the protector shall be in accordance with Section 921.2a of this specification.

921.3 MATERIALS. Material selection for Intervention Fixtures shall be in accordance with Sections 400 and 921.2g(2) of this specification.

921.4 WELDING. Welding requirements for intervention fixtures to be in accordance with Section 500 of this specification.

921.5 TESTING. Design verification testing shall comply with Section 307 of this specification.

Factory acceptance testing shall comply with Section 600 of this specification. In addition, all intervention fixtures shall be tested in accordance with manufacturer's written specification prior to delivery to verify:

- Functional performance
- Accessibility by the intervention system and intervention tool (may be verified by mockups, jigs, or fixtures).
- Pressure integrity of fluid coupling intervention fixtures by hydrostatic testing to a minimum of 1.5 times the working pressure for a minimum of 3 minutes.

921.6 MARKING. Marking shall be in accordance with Sections 700 and 921.2a(5) of this specification.

921.7 STORING AND SHIPPING. Storing and shipping of intervention fixtures to be in accordance with Section 800 of this specification.

922 SUBSEA TREE ASSEMBLY. This section provides specification requirements for the assembly of equipment covered in Section 900 of this specification to configure the subsea tree.

NOTE: *Subsea tree assembly configurations vary depending on wellhead type, service, well shut-in pressure, water depth, reservoir parameters and environmental factors. As such, the subsea tree configuration requirements specified in this section may not be applicable or desirable for all applications.*

922.1 DESIGN. This section covers the assembly of equipment to configure the subsea tree, including valve placements and valve types. A schematic for a typical dual bore subsea tree is illustrated in Figure 922.1, while Figure 922.2 illustrates a typical single bore tree used with a tubing spool. Figures in this section are for illustration purposes only and should not be construed as limitations to applications.

922.1a General. Equipment used in the assembly of the subsea tree which is covered in Sections 901 through 921 of this specification shall meet the requirements of Sections 901 through 921.

Equipment used in the assembly of the subsea tree which is not covered in Sections 901 through 921 shall comply with manufacturer's written specifications.

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

922.1b Master Valves. Any valve in the vertical bore of the tree between the wellhead and the tree side outlet shall be defined as a master valve. A subsea tree shall have one or more master valves in the vertical production (injection) bore, at least one of which shall be a hydraulically operated fail-closed valve.

922.1c Wing Valves. A wing valve is any valve in the subsea tree assembly that controls either the production (injection) or annulus flow path and is not in the vertical bore of the tree. Each side outlet for production (injection) and annulus flow path of the subsea tree shall have at least one wing valve.

922.1d Swab Closures. Any vertical bore that passes through the subsea tree assembly, which could be used in workover operations, shall be equipped with at least one pressure controlling (swab) closure located above the uppermost tree side outlet. Swab closures may be caps, stabs, tubing plugs, or valves.

Removal or opening of the swab closure shall not result in any diametrical restriction through the vertical bore of the subsea tree.

Swab valves may be either manual or hydraulically operated.

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

922.1e Crossover Valves. A crossover valve is an optional valve that, when opened, allows communication between two tree paths that are normally isolated. Crossover valves are not required on API Specification 17D equipment.

922.1f Tree Assembly Pressure Closures. The subsea tree assembly shall meet the pressure closure requirements of this section.

NOTE: *This specification is only concerned with the pressure closure requirements contained within the subsea tree assembly. Other industry recognized pressure closures contained in the total system such as downhole SCSSV's or flowline valves are beyond the scope of this specification. It is not intended that the multiple pressure closure requirements of the subsea tree assembly replace the need for other system pressure closures.*

922.1f(1) Production (Injection) Flow Paths. There shall be at least two hydraulically operated fail-closed valves in the production (injection) flow stream of the subsea tree.

- In the case of a subsea tree with only one hydraulically operated fail-closed master valve, then at least one wing valve shall also be a hydraulically operated fail-closed valve.
- In the case of a subsea tree with two hydraulically operated fail-closed master valves, then the wing valves may be either manual or hydraulically operated.

Figure 922.3 illustrates some of the combinations of master and wing valving which meet the subsea tree pressure closure criteria of this section and the requirements of Sections 922.1b thru 922.1d of this specification.

922.1f(2) Annulus Flow Paths. All annulus paths of the tree or tubing hanger spool shall have at least two pressure controlling closures, one of which shall be a hydraulically operated fail-closed valve. Figure 922.4 illustrates some of the combinations of annulus valving which meet the pressure closure criteria of this section and the requirements of Sections 922.1c and 922.1d of this specification.

922.1f(3) Production and Annulus Bore Penetrations. Any penetrations into the production (injection) flow stream of the subsea tree shall be made above the lowest master valve. Flanges, clamp hubs or other end connections meeting the requirements of Sections 901, 902, 904, 905 and 906 of this specification, as applicable, shall be used to provide connections for the penetrations to the tree.

There shall be at least two fail-closed pressure closures, one of which must be hydraulically operated fail-closed, between the wellhead and any penetration leading into either the production (injection) or annulus path of the tree or tubing spool.

Flow closed check valves are acceptable as fail-closed closures for monitoring or chemical injection penetration lines that are one-inch (25.4 mm) nominal diameter or smaller.

Devices that terminate directly on the tree such as transducers do not require penetration valving, provided there is a pressure closure between the tree bore and the environment. These devices shall comply with Section 606 of this specification, if there is no hydraulically operated fail-closed valve between the penetration and the wellhead.

Figure 922.5 illustrates various combinations of penetration valving which meets the requirements of this section.

922.1f(4) Downhole Safety Valve Control Line Penetrations. At least one pressure controlling closure shall be used at all downhole safety valve control line penetrations that pass through either the tree or tubing spool. Manual valves are acceptable closure devices.

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

Check valves shall not be used anywhere in the downhole safety valve control line circuit.

The right side of Figure 922.6 illustrates typical subsea tree valving for SCSSV circuits that meets the requirements of this section.

922.1f(5) Downhole Chemical Injection Line Penetrations. The subsea tree assembly shall provide for two fail-closed valves in all chemical injection lines which pass through the tubing hanger. Flow-closed check valves are acceptable as one of the fail-closed valves for line sizes of one-inch (25.4 mm) nominal diameter or smaller. At least one of the fail-closed valves shall be a hydraulically operated fail-closed valve. Flanges, clamp hubs or other end connectors meeting the requirements of Sections 901, 902, 904, 905, and 906, as applicable, of this specification shall be used to provide connections for the penetrations to the tree. The left side of Figure 922.6 illustrates typical subsea tree valving that meets the requirements of this section.

922.2 MATERIALS. Materials used in the assembly of subsea trees shall conform to Section 400 of this specification.

922.3 WELDING. Welding during the assembly of subsea trees shall conform to Section 500 of this specification.

922.4 TESTING. This section covers testing of subsea tree assemblies.

922.4a Performance Verification Testing. There are no performance verification testing requirements for subsea tree assemblies. However, all parts and equipment covered in Section 900 of this specification used in the assembly of subsea trees shall conform to its applicable performance verification testing requirements.

922.4b Factory Acceptance Testing. The subsea tree assembly shall be tested in accordance with API Specification 6A, Section 605.9. For TFL applications, the subsea tree assembly shall be drift tested in accordance with API Recommended Practice 17C, Sections 3.3b, 3.4a, 4.3a, 4.5a, and 4.8a.

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

NOTE: *Integration testing of total system is beyond the scope of this specification.*

922.5 MARKING. Marking for assembled subsea trees shall conform with Section 700 of this specification. The subsea tree assembly shall be tagged with a nameplate labeled as "Subsea Tree Assembly", located on the master valve or tree valve block, and contain the following information as a minimum:

- Name and Location of Assembler/Date
- PSL Designation of Assembly
- Rate Working Pressure of Assembly
- Temperature Rating of Assembly
- Material Class of Assembly
- Drift Test/Date
- 17D

922.6 STORING AND SHIPPING. The subsea tree assembly shall be stored and shipped in accordance with Section 800 of this specification. No part or equipment on the assembled subsea tree shall be removed or replaced during storage or shipping unless the tree is successfully retested and then re-tagged.

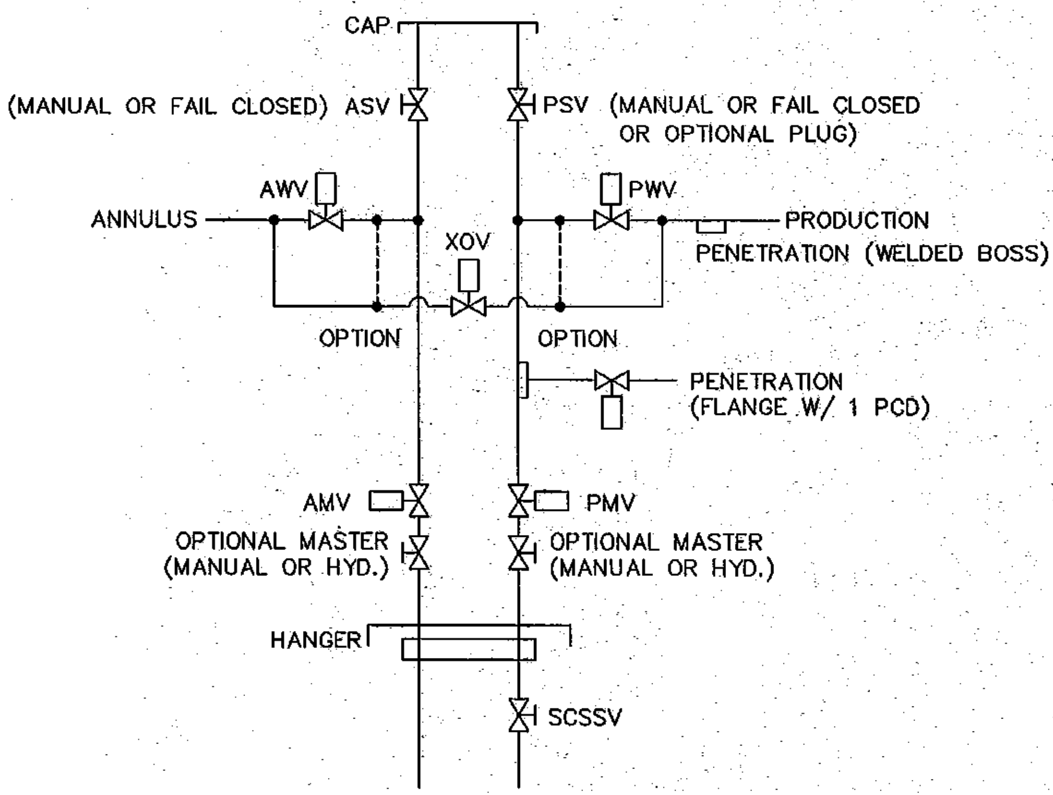


FIGURE 922.1
EXAMPLE OF DUAL BORE TREE ON SUBSEA WELLHEAD

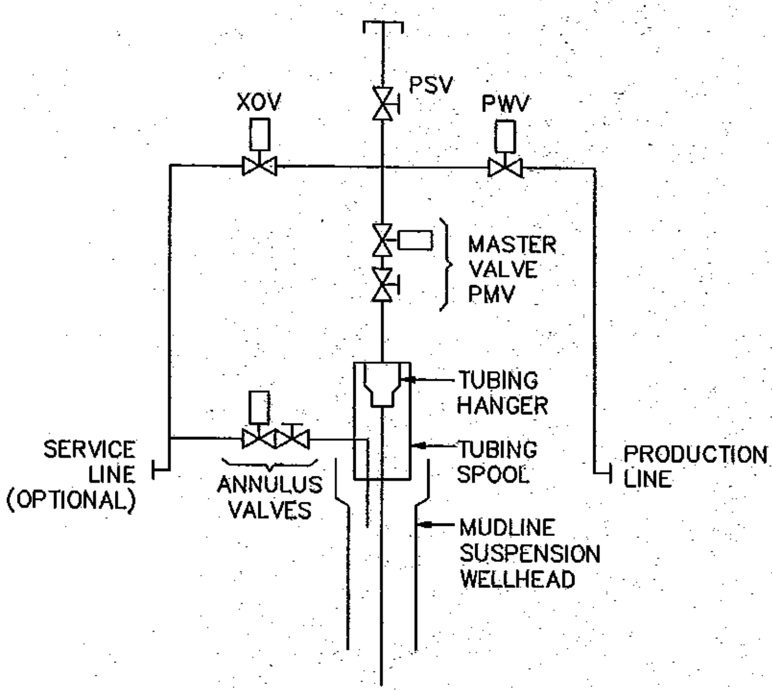


FIGURE 922.2
EXAMPLE OF SINGLE BORE TREE ON MUDLINE TIE-BACK

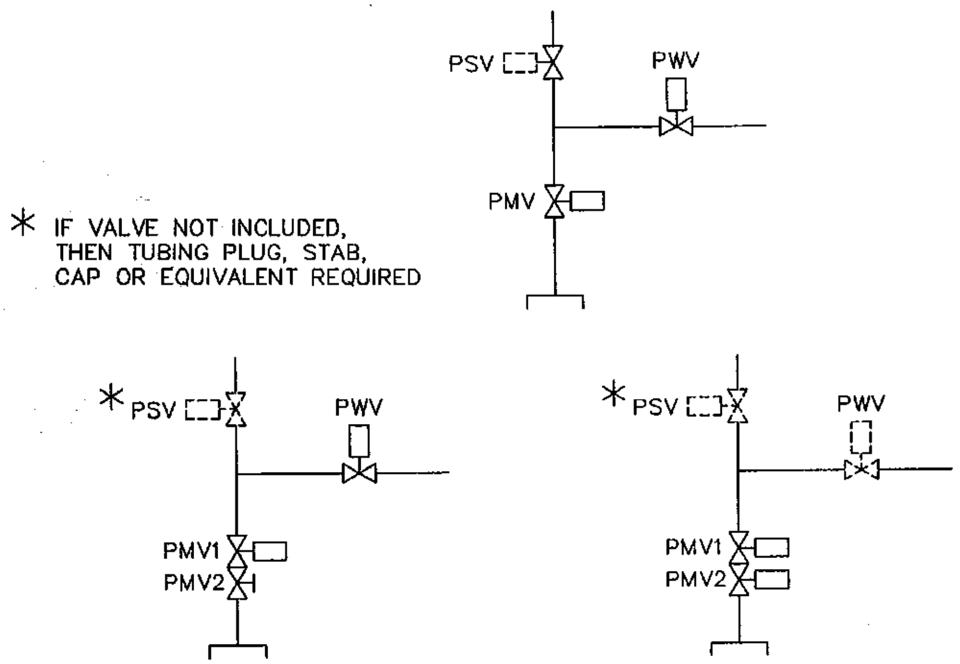


FIGURE 922.3
EXAMPLES OF TREE MASTER AND WING VALVES

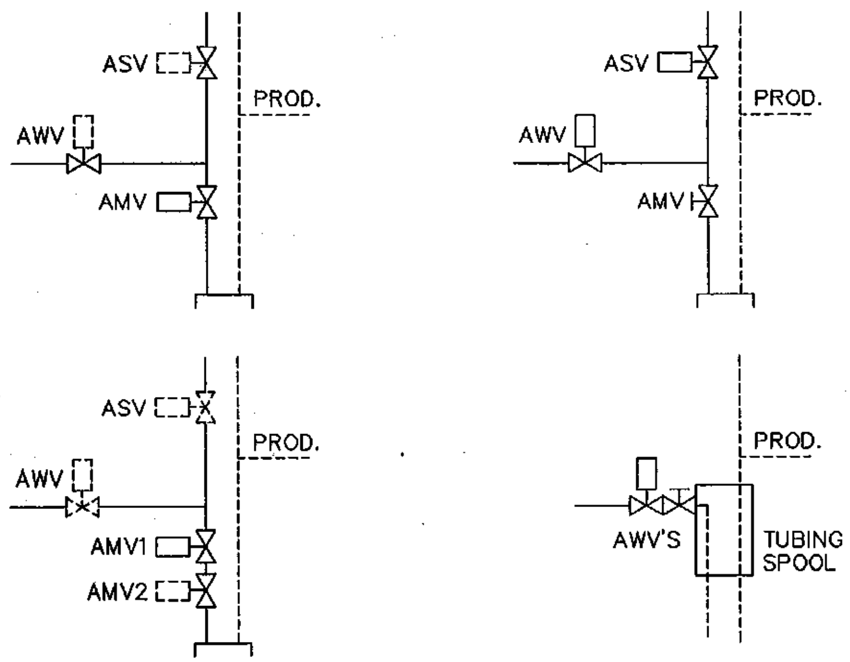


FIGURE 922.4
EXAMPLES OF ANNULUS VALVING

NOTE: THE DOTTED INCLUSIONS ARE OPTIONAL.

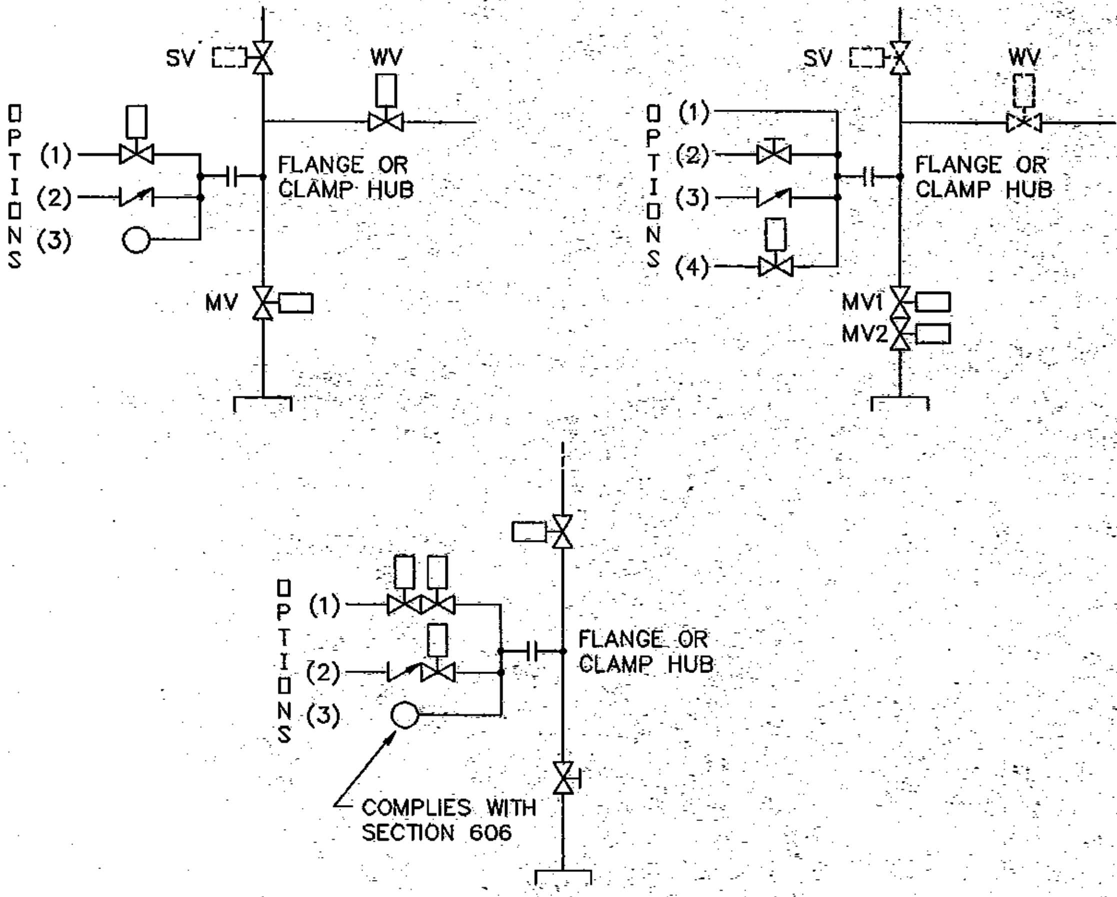


FIGURE 922.5
EXAMPLES OF TREE BORE PENETRATIONS

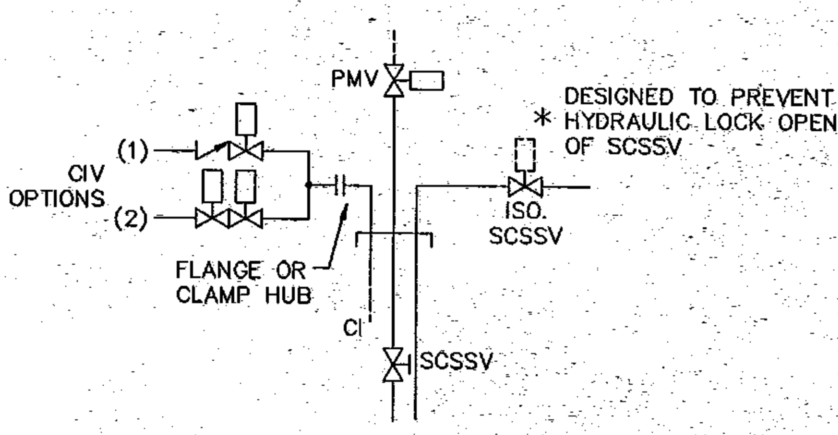


FIGURE 922.6
EXAMPLES OF TREE VALVING FOR
DOWNHOLE CHEMICAL INJECTION AND SCSSV'S

NOTE: THE DOTTED INCLUSIONS ARE OPTIONAL.

SECTION 1000
SUBSEA WELLHEAD AND TUBING HANGER EQUIPMENT — SPECIFIC REQUIREMENTS

1001 SUBSEA WELLHEAD EQUIPMENT.

1001.1 GENERAL. This section describes Subsea Wellhead Systems which are normally run from floating drilling rigs. It establishes standards and specifications for this equipment. Guidelineless Systems are not addressed in this specification. The Subsea Wellhead System supports and seals casing strings. It also supports the blow-out preventer stack (BOP) during drilling, and the subsea tree and possibly the tubing hanger after completion. The Subsea Wellhead System is installed at or near the mudline.

All pressure containing and pressure controlling parts included as part of the subsea wellhead equipment shall be designed to meet all of the requirements of the NACE Standard MR-01-75 "Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment." These parts include:

- Wellhead Housing
- Casing Hanger Bodies
- Annulus Seal Assemblies

The following parts or features are excluded from the NACE requirements:

- Lock Rings
- Load Rings
- Load Shoulders
- 16" (406 mm) Suspension Equipment
- Bore Protectors and Wear Bushings

1001.2 TEMPORARY GUIDE BASE (TGB).

1001.2a General. The temporary guide base (TGB) provides a guide template for drilling the conductor hole, and stabbing the conductor pipe. It compensates for misalignment from irregular ocean bottom conditions, and provides a support base for the permanent guide base. For guideline systems, it also establishes the initial anchor point for the guidelines.

1001.2b Design. The design of TGB's shall comply with Section 300 of this specification:

1001.2b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing the TGB:

- Ballast
- Guideline Tension
- Weight of Conductor Pipe
- Weight of Permanent Guide Base Assembly
- Soil Reaction

The TGB shall be capable of supporting, as a minimum, a static load of 175,000 pounds (780000 Newtons) on the interface with the permanent guidebase while the TGB is supported at four locations, equally spaced 90 ± 2 degrees apart and a minimum of 62 inches (1575 mm) from the center (radial measure).

1001.2b(2) Dimensions.

(a) The TGB minimum bearing area shall be 75 square feet (7 square meters). This area may be augmented with weld-on or bolt-on extensions to compensate for soil strengths and anticipated loads.

(b) TGB should pass through a 15 foot (5 meter) square opening or as specified by the manufacturer.

(c) TGB shall provide four guideline anchor points in position to match the guideposts on the PGB.

(d) Together with the permanent guide base, the TGB shall allow a minimum angular misalignment of 5 degrees between the conductor pipe and the temporary guide base.

(e) TGB shall provide a minimum storage volume of 75 cubic feet (2 cubic meters) for ballast material.

1001.2c Materials.

1001.2c(1) The TGB shall be fabricated from structural steel shapes and plates which conform to Section 400 of this specification.

1001.2c(2) Coatings shall conform to Section 304.7 of this specification.

1001.2d Testing. Performance verification testing shall conform to Section 307.5 of this specification. No factory acceptance testing is required.

1001.3 PERMANENT GUIDE BASE (PGB).

1001.3a General. The permanent guide base (PGB) provides entry into the well prior to BOP installation and, along with the four guideposts, gives guidance for running the subsea BOP stack or the subsea tree. It establishes structural support and final alignment for the wellhead system, and provides a seat and lock down for the conductor housing. PGB's can be built as a single piece or split into two pieces to ease handling and installation. Optionally, they may include provisions for retrieval and to react flowline loads.

1001.3b Design. The design of PGB's shall comply with Section 300 of this specification.

1001.3b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing the PGB (see Figure 1001.3):

- Conductor Pipe Weight
- Conductor Housing Weight
- Jetting String Weight when supported on the Spider Beams
- Guideline Tension (see Figure 1001.3)
- Flowline Pull-In, Connection, or Installation Loads (see Figure 1001.1)

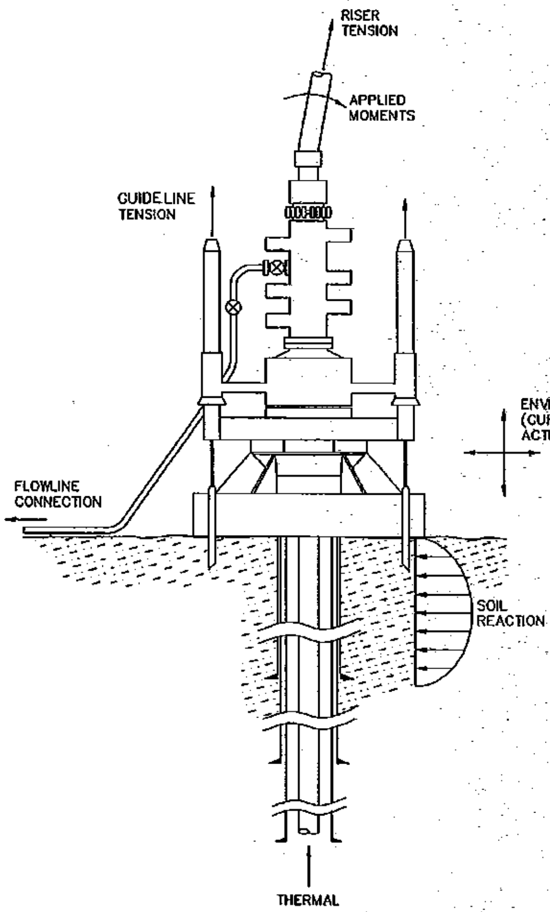
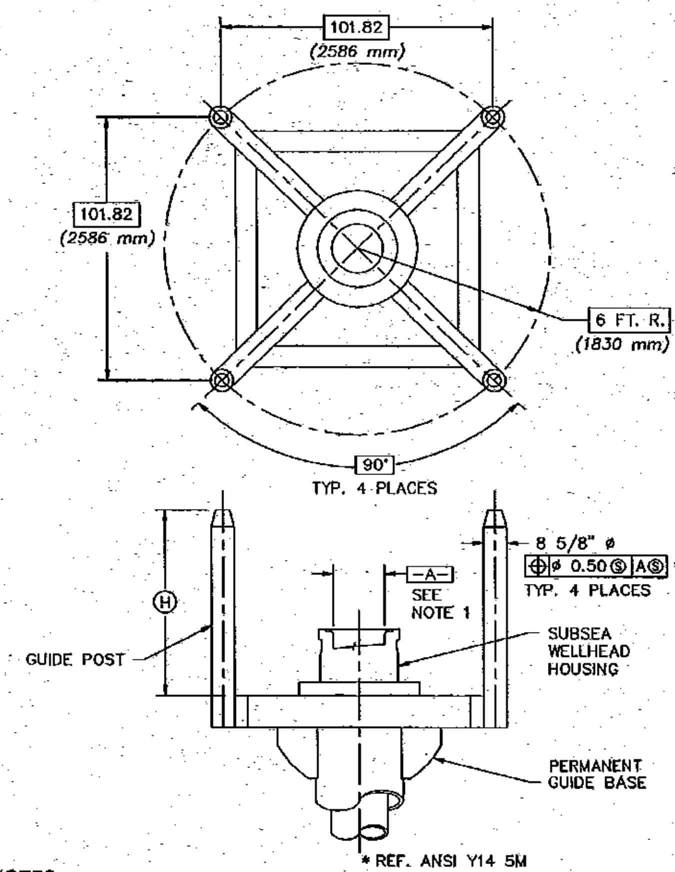


FIGURE 1001.1
LOADS AND REACTIONS
FOR A SUBSEA COMPLETION

FIGURE 1001.2
PERMANENT GUIDE BASE & GUIDE POST
DIMENSIONING AND TOLERANCING



NOTES:

1. GUIDE POSTS POSITIONAL TOLERANCES ARE DETERMINED RELATIVE TO THE WELLHEAD HOUSING BORE (DATUM —A—) METHOD OF MEASUREMENT TO BE SPECIFIED BY THE MANUFACTURER
2. CUMULATIVE TOLERANCES BETWEEN ALL INTERFACING COMPONENTS MUST BE LESS THAN OR EQUAL TO THE POSITIONAL TOLERANCE SHOWN
3. DIMENSION Ⓗ TO BE 8 FT. (2500 mm) MINIMUM

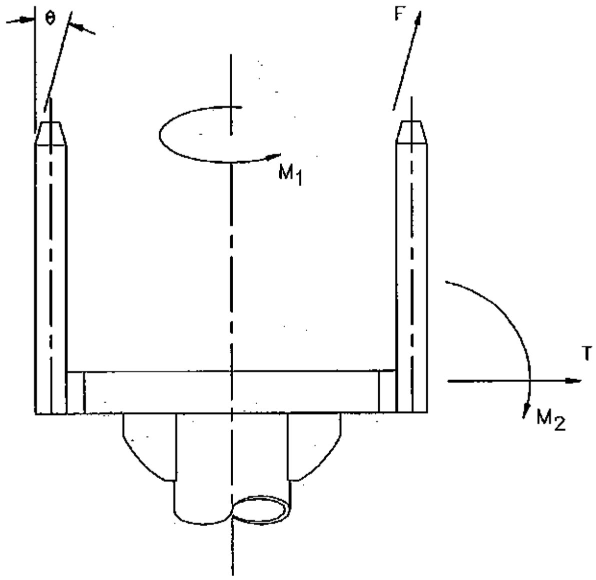


FIGURE 1001.3
PERMANENT GUIDE BASE (PGB) LOADS

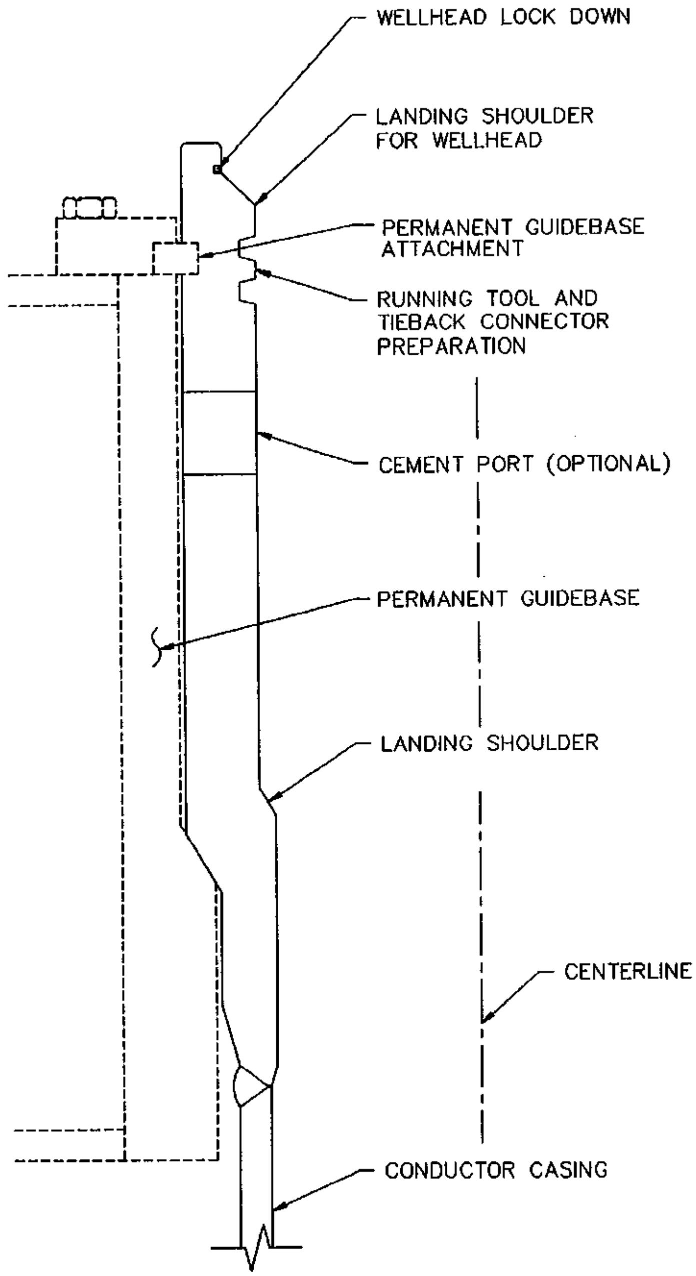


FIGURE 1001.4
CONDUCTOR HOUSING

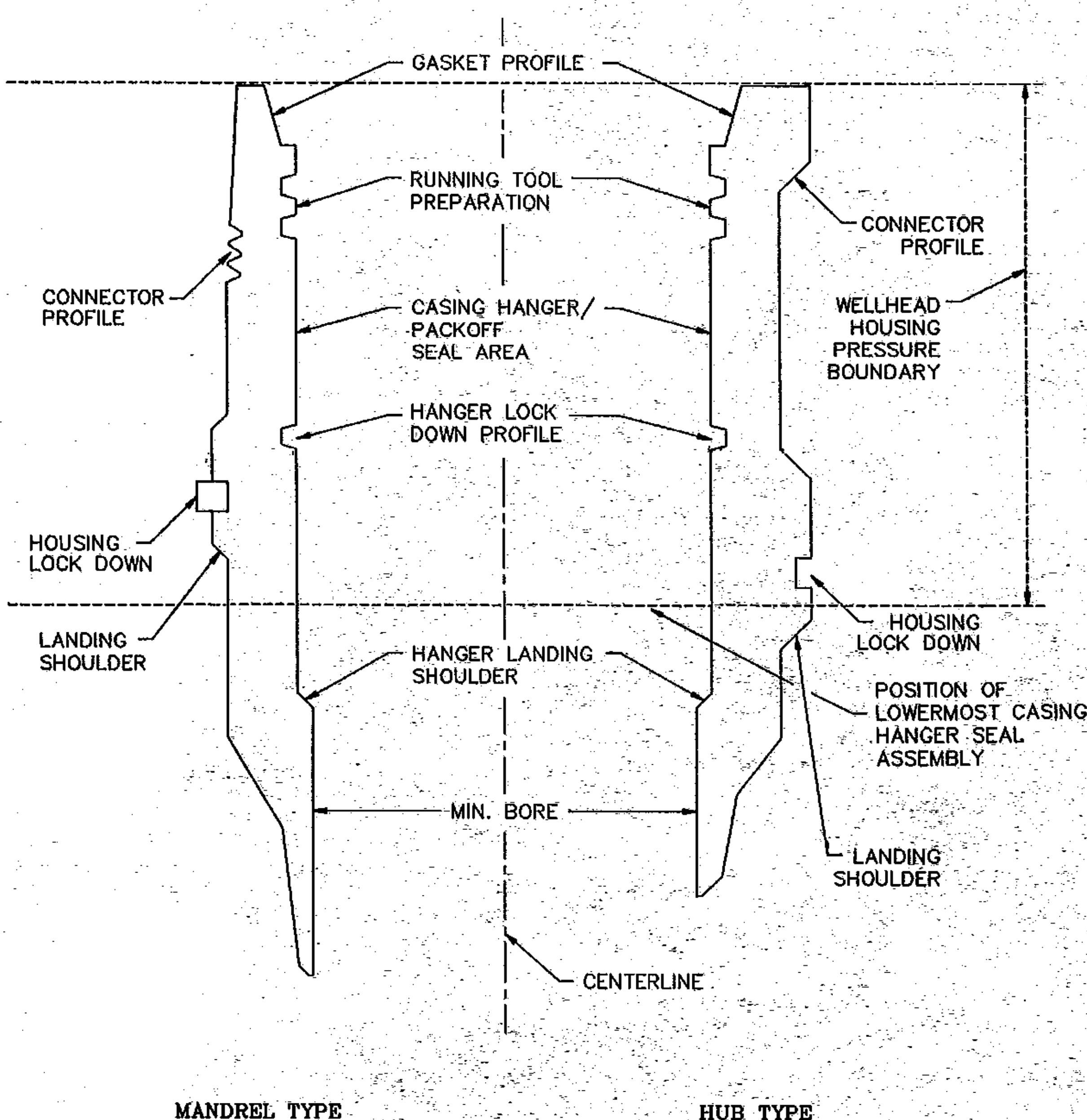


FIGURE 1001.5
WELLHEAD HOUSINGS

- Environmental
- Reaction for TGB

The PGB shall be capable of supporting, as a minimum, a static load of 175,000 pounds (780000 Newtons) on the interface with the conductor housing while the PGB is supported at four locations equally spaced 90 ± 2 degrees apart and a miniumum of 62 inches (1575 mm) from the center (radial measure).

1001.3b(2) Dimensions.

(a) The dimensions of the PGB shall conform to the dimensions shown in Figure 1001.2.

(b) The guideposts shall be fabricated of 8 5/8" (219 mm) O.D. pipe or tubulars.

(c) The length of the guidepost (dimension "H" of Figure 1001.2) shall be 8 feet (2500 mm) minimum.

1001.3b(3) Functional Requirements.

(a) When used with the temporary guide base, the PGB shall allow a minimum angular misalignment of 5 degrees between a 30 inch nominal (762 mm) conductor pipe and the TGB. For other conductor pipe sizes, the manufacturer shall document the misalignment capability.

(b) Guideposts shall be field replaceable without welding.

(c) Guideposts can be either slotted or non-slotted. For slotted guideposts, provisions shall be made to insert guidelines of at least 3/4 inch (19 mm) O.D. into the post with retainers at the top and at or near the bottom of the post.

(d) Provisions shall be made to attach guidelines to the top of the guideposts. These provisions shall be capable of being released and re-established.

1001.3c Materials.

1001.3c(1) The PGB shall be fabricated from structural steel shapes and plates which conform to Section 400 of this specification.

1001.3c(2) Coatings shall conform to Section 304.7 of this specification.

1001.3d Testing. Performance verification testing shall conform to Section 307.5 of this specification. No factory acceptance testing is required.

1001.4 CONDUCTOR HOUSING.

1001.4a General. The conductor housing attaches to the top of the conductor pipe to form the basic foundation of a subsea well. The housing typically has a means of attaching to the PGB which prevents rotation of the PGB with respect to the housing.

A typical conductor housing profile is shown in Figure 1001.4. The internal profile of the conductor housing includes a landing shoulder suitable for supporting the wellhead housing and the loads imposed during the drilling operation. Running tool preparations should also be a part of the internal housing profile. Cement return passageways may be incorporated in the conductor housing/PGB assembly to allow cement and mud returns to be directed below the PGB.

1001.4b Design. The design of the conductor housing shall comply with Section 300 of this specification.

1001.4b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing the conductor housing (refer to Section 1001.2b(1)):

- Wellhead Loads
- Riser Forces
- PGB Loads (refer to Figures 1001.1 and 1001.3)
- Environmental Loads
- Pressure Loads
- Thermal Loads

The interface between the conductor housing and the PGB shall be designed for a rated load of at least 175,000 pounds (780000 Newtons). The conductor housing shall have a minimum rated working pressure of 1,000 psi (6,9 MPa).

1001.4b(2) Dimensions.

(a) The following dimensions shall apply to 30 inch (762 mm) nominal Conductor Housings:

Minimum I.D. 26.2 inch (665 mm)

Maximum O.D. 37.38 inch (950 mm)

(b) The Conductor Housing is not limited to the 30" (762 mm) size. Rotary table dimensions should be considered when selecting the outside diameter of the conductor housing. The drill bit gage diameter used for the next string of casing plus 1/8 inch (3 mm) clearance should be considered when selecting the internal diameter of the conductor housing.

1001.4b(3) Bottom Connection. If the bottom end connection is to be welded, it shall be prepared for a full penetration butt-weld.

1001.4c Materials.

1001.4c(1) The housing body material shall comply with Section 400 of this specification.

1001.4c(2) Impact testing is not required.

1001.4d Testing. Performance verification testing shall conform to Section 307.5 of this specification. No factory acceptance testing is required.

1001.5 WELLHEAD HOUSING.

1001.5a General. The wellhead housing lands inside the conductor housing. It provides pressure integrity for the well, suspends the surface and subsequent casing strings and tubing hanger and reacts external loads. The BOP stack or subsea tree attaches to the top of the wellhead housing using a compatible wellhead connector. The wellhead housing shall accept tubing hangers or tubing hanger adapter. The standard system sizes are given in Table

1001.1. Figure 1001.5 shows two profiles of typical wellhead housings.

1001.5b Design. The design of wellhead housings shall comply with Section 300 of this specification.

1001.5b(1) Loads. As a minimum, the following loads shall be considered and documented by the manufacturer when designing the Wellhead Housing:

- Riser Forces (drilling, production, and workover)
- BOP Loads
- Subsea Tree Loads
- Pressure
- Radial Loads
- Thermal Loads
- Environmental Loads
- Flowline Loads
- Suspended Casing Loads
- Conductor Housing Reactions
- Tubing Hanger Reactions
- Hydraulic Connector Loads

1001.5b(2) Connections.

(a) **Top Connection.** The top connection should be of a hub or mandrel type (see Figure 1001.5) as specified by the manufacturer. The gasket profiles shall be manufactured from or inlayed with corrosion resistant material per Section 404.3 of this specification.

(b) **Bottom Connection.** The high-pressure housing attaches to the top of the surface casing to form the basic foundation of a subsea well. If the bottom connection is to be welded, it shall be prepared for a full penetration butt-weld.

(c) **Body Penetrations.** Body penetrations within the housing pressure boundary are not permitted.

1001.5b(3) Dimensions.

(a) The minimum vertical bore of the wellhead housing shall be as shown in Table 1001.1.

(b) Dimensions of the wellhead pressure boundary (see Figure 1001.5) shall be per the manufacturer's written specification.

1001.5b(4) Rated Working Pressure. The maximum rated working pressure for the wellhead housing pressure boundary (see Figure 1001.5) shall be 2,000, 5,000, 10,000, or 15,000 psi (13,8; 34,5; 69,0 or 103,5 MPa). Selection of the rated working pressure should consider the maximum expected SCSSV operating pressure (see Section 1002.2d).

1001.5c Materials. The housing body material shall comply with Section 400 of this specification.

Extension ribs or structural components that may be attached to the housing body shall comply with Sections 300 and 500 of this specification.

1001.5d Testing.

1001.5d(1) Performance Verification Testing. Performance verification testing of wellhead housings shall conform to Section 307 of this specification.

1001.5d(2) Factory Acceptance Testing. All wellhead housings shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic test is performed to verify the pressure integrity of the housing pressure boundary. They shall be tested to the requirements of API Specification 6A, Section 605, except that the tests (including PSL 2) shall have a secondary holding period of not less than 15 minutes.

The hydrostatic body test pressure shall be determined from the housing rated working pressure. The hydrostatic body test pressure shall not be less than the following values:

Rated Working Pressure Rating (PSI)	(MPa)	Body Hydrostatic Test Pressure (PSI)	(MPa)
2,000	(13,8)	4,000	(27,6)
5,000	(34,5)	10,000	(69,0)
10,000	(69,0)	15,000	(103,5)
15,000	(103,5)	22,500	(155,2)

Wellhead housings shall show no visible leakage during each pressure holding period.

1001.6 CASING HANGERS.

1001.6a General. The subsea casing hanger is installed on top of each casing string and supports the string when landed in the wellhead housing. It is configured to run through the drilling riser and subsea BOP stack, land in the subsea wellhead, and support the required casing load. It shall have provisions for an annulus seal assembly, support loads generated by BOP test pressures above the hanger and loads due to subsequent casing strings. Means shall be provided to transfer casing load and test pressure load to the wellhead housing or to the previous casing hanger.

A lockdown mechanism, if required, is used to restrict movement of the casing hanger due to thermal expansion or annulus pressure. An external flowby area allows for returns to flow past the hanger during cementing operations and is designed to minimize pressure drop, while passing as large a particle size as possible. A pup joint of casing should be installed on the hanger in the shop. This reduces the risk of damage during handling.

Subsea casing hangers shall be treated as pressure controlling equipment as defined in API Specification 6A.

1001.6b Design. The design of casing hangers shall comply with Section 300 of this specification.

TABLE 1001.1
WELLHEAD SYSTEMS
STANDARD SIZES AND TYPES

NOMINAL SYSTEM DESIGNATION (INCHES-PSI) (MM-MPa)	BOP STACK CONFIGURATION	HIGH PRESSURE HOUSING WORKING PRESSURE (PSI) (MPa)	MINIMUM VERTICAL BORE (INCHES) (mm)
18-3/4-10M (476-69)	SINGLE	10,000 (69,0)	17.56 (446)
18-3/4-15M (476-103)	SINGLE	15,000 (103,5)	17.56 (446)
16-3/4-5M (425-35)	SINGLE	5.000 (34,5)	15.12 (384)
16-3/4-10M (425-69)	SINGLE	10,000 (69,0)	15.12 (384)
20-3/4-21-1/4-2M (527-540-14)	DUAL	2,000 (13,8)	18.59 (472)
13-5/8-10M (346-69)		10,000 (69,0)	12.31 (313)
21-1/4-5M (540-35)	DUAL	5,000 (34,5)	18.59 (472)
13-5/8-15M (346-103)		15,000 (103,5)	12.31 (313)
18-3/4-10M (476-69)	DUAL	10,000 (69,0)	17.56 (446)
13-5/8-15M (346-103)		15,000 (103,5)	12.31 (313)

1001.6b(1) Loads. As a minimum, the following loads shall be considered and documented by the manufacturer when designing casing hangers:

- Suspended Weight
- Overpull
- Pressure, Internal and External
- Thermal
- Torsional
- Radial
- Impact

1001.6b(2) Threaded Connections. The type of casing threads on the hanger shall be per API Specification 6A, Section 902 or 918.

1001.6b(3) Vertical Bore.

(a) **Full Opening Vertical Bore.** The minimum vertical bores for casing hangers shall be per Table 1001.2. Equipment conforming to this requirement shall be referred to as having full opening bores.

TABLE 1001.2
MINIMUM VERTICAL BORE SIZES FOR CASING HANGERS AND WEAR BUSHINGS

CASING O.D. INCHES (MM)	MINIMUM VERTICAL BORE INCHES (MM)
7" (178)	6.03" (153)
7-5/8" (194)	6.78" (172)
8-5/8" (219)	7.66" (195)
9-5/8" (244)	8.53" (217)
10-3/4" (273)	9.53" (242)
11-3/4" (298)	10.66" (271)
13-3/8" (340)	12.28" (312)
16" (406)	14.81" (376)

(b) **Reduced Opening Vertical Bores.** Reduced vertical bores may also be supplied.

1001.6b(4) Outside Profile. The outside profile shall be per the manufacturer's written specification.

1001.6b(5) Casing Hanger Ratings. The load and pressure ratings for casing hangers may be a function of the tubular grade of material and wall section as well as the wellhead equipment in which it is installed. Manufacturers shall determine and document the load/pressure ratings for casing hangers as defined below:

(a) **Hanging Capacity.** The manufacturer's stated hanging capacity rating for a casing hanger includes the casing thread (normally a female thread) cut into the hanger body.

(b) **Pressure Rating.** The manufacturer's stated pressure rating for a casing hanger includes the hanger body and the casing thread (normally a female thread) cut into the lower end of the hanger.

NOTE: *The user is responsible for determining the working pressure of a given weight and grade of casing.*

(c) **BOP Test Pressure.** The BOP test pressure rating for a casing hanger is the maximum pressure which may be applied to the upper portion of the hanger body, and to the annulus seal assembly. This rating specifically excludes the casing connection at the lower end of the casing hanger.

The BOP test pressure rating for a casing hanger shall be equal to the rated working pressure of the wellhead housing that the hanger is installed in or as shown in Table 1001.3.

(d) **Support Capacity.** The manufacturer's stated support capacity is the rated weight which the casing hanger(s) are capable of transferring to the wellhead housing or previous casing hanger(s). The effects of full rated internal working pressure shall be included.

1001.6b(6) Flowby Area. Casing hanger minimum flowby areas shall be documented by the manufacturer and maintained for each casing hanger assembly.

TABLE 1001.3
MINIMUM RATED PRESSURE FOR BOP TESTING

CASING HANGER SIZE	BOP TEST PRESSURE RATING
18 3/4" x 16" (476 mm x 406 mm)	3,000 PSI (20,7 MPa)
18 3/4" x 13 3/8" (476 mm x 340 mm)	10,000 PSI (69,0 MPa)

1001.6c Materials. Materials used for casing hangers shall comply with Section 400 of this specification.

1001.6d Testing.

1001.6d(1) Performance verification testing of subsea wellhead casing hangers shall conform to Section 307 of this specification. Performance verification testing for internal pressure shall be performed to verify the structural integrity of the hanger and shall be independent of the casing grade and thread.

1001.6d(2) Factory acceptance testing of subsea wellhead casing hangers need not include a hydrostatic test. A dimensional check or drift test shall be performed on the hanger to verify the minimum vertical bore (refer to Table 1001.2).

1001.7 ANNULUS SEAL ASSEMBLIES.

1001.7a General. Annulus Seal Assemblies provide pressure isolation between each casing hanger and the wellhead housing. They may be run simultaneously with the subsea casing hanger, or separately. Annulus seal assemblies are actuated by various methods, including torque, weight, and/or hydraulic pressure.

Subsea annulus seal assemblies shall be treated as pressure controlling equipment as defined in API Specification 6A.

1001.7b Design. The design of subsea annulus seal assemblies shall comply with Section 300 of this specification.

1001.7b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing the annulus seal assemblies:

- Setting Loads
- Thermal Loads
- Pressure Loads
- Releasing and/or Retrieval Loads

1001.7b(2) Rated Working Pressure. The annulus seal assembly shall contain pressure from above equal to the rated working pressure of the casing hanger (see Section 1001.6b(5)(b)).

1001.7b(3) Outside Profile. The outside profile shall be per the manufacturer's written specification.

1001.7c Materials. Materials used in annulus seal assemblies shall comply with Section 400 of this specification.

1001.7d Testing.

1001.7d(1) Performance verification testing shall be performed in accordance with Section 307 of this specification.

1001.7d(2) Factory acceptance testing is not required.

1001.8 BORE PROTECTORS AND WEAR BUSHINGS.

1001.8a General. A bore protector protects annulus seal assembly sealing surfaces inside the wellhead housing before casing hangers are installed. After a casing hanger is run, a corresponding size wear bushing is installed to protect the remaining annular sealing surfaces and the previously installed annular seal assemblies and casing hangers. They are generally not pressure retaining devices. However, wear bushings may be designed for BOP stack pressure test loading.

1001.8b Design.

1001.8b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing the bore protectors or wear bushings:

- BOP Test Pressure Loading
- Radial Loads

Bore Protectors or Wear Bushings do not need to meet the requirements of Section 300 of this specification.

1001.8b(2) Vertical Bores.

(a) **Full Opening Vertical Bore.** The minimum vertical bore of the bore protector shall be per Table 1001.4. The minimum vertical bore through wear bushings shall be per Table 1001.2. Bore protectors and wear bushings conforming to these requirements shall be referred to as having full opening bores.

TABLE 1001.4
MINIMUM VERTICAL BORES FOR BORE PROTECTORS

NOMINAL BOP STACK SIZES INCHES (MM)	MINIMUM VERTICAL BORE INCHES (MM)
13-5/8" (346)	12.31" (312)
16-3/4" (425)	15.12" (384)
18-3/4" (476)	17.56" (446)
20-3/4" - 21-1/4" (527-540)	18.59" (472)

(b) **Reduced Opening Vertical Bore.** Reduced vertical bores may also be supplied.

1001.8b(3) Outside Profile. The outside profile shall be per the manufacturer's written specifications.

1001.8b(4) Rated Working Pressure. Bore protectors and wear bushings are not normally designed to retain pressure.

1001.8b(5) Lockdown/Antirotation. Means shall be provided to restrain or lock the wear bushings or bore protector within the housing. This feature may also be designed to minimize rotation.

1001.8c Materials. The materials used in bore protectors and wear bushings shall comply with the manufacturer's written specifications.

1001.8d Testing. Bore protectors and wear bushing shall be dimensionally inspected to confirm minimum vertical bore.

1001.9 CORROSION CAP. The function of the corrosion cap is to protect the subsea wellhead from contamination by debris, marine growth, and corrosion. These caps usually are non-pressure containing and lock onto the external profile of the wellhead housing. If a pressure retaining cap is utilized, means shall be provided for sensing and relieving pressure prior to releasing the cap. The cap is installed just prior to temporary abandonment of a well.

1001.10 RUNNING, RETRIEVING AND TESTING TOOLS. Tools for running, retrieving, and for testing all subsea wellhead components including guidance equipment, housings, casing suspension equipment, annulus sealing equipment and protective devices are beyond the scope of this document.

Refer to Appendix G of this specification for recommended guidelines for the design and testing of this equipment.

1001.11 WELDING. Subsea wellhead equipment shall be welded in accordance with Section 500 of this specification.

1001.12 MARKING. Subsea wellhead equipment shall be marked in accordance with Section 700 of this specification.

1001.13 STORING AND SHIPPING. Subsea wellhead equipment shall be stored and shipped in accordance with Section 800 of this specification.

1002 TUBING HANGER SYSTEM.

1002.1 GENERAL. The Tubing Hanger System is comprised of a tubing suspension device called a tubing hanger and an associated tubing hanger running tool. This specification is limited to tubing hangers which are landed in a wellhead or tubing spool. A tubing annulus seal is effected and the hanger is locked in place. It is designed to provide a means for making a pressure-tight connection between the tubing string(s), tubing annulus and the corresponding subsea tree or tubing hanger running tool bores. It may also provide a continuous means of communication or control of downhole SCSSV's, electrical transducers, and/or other devices. There are two basic types of tubing hangers, (1) concentric and (2) eccentric (those that require orientation to align multiple tubing bores or control ports).

1002.2 DESIGN. The design of tubing hanger systems shall comply with Section 300 of this specification.

1002.2a Loads. As a minimum, the following loads shall be considered and documented by the manufacturer when designing the tubing hanger system:

- Suspended Weight
- Overpull
- Pressure, Internal and External
- Thermal Loads
- Torsional Loads
- Radial Loads
- Oriented Loads
- Tree Reacting Loads

1002.2b Threaded Connections.

1002.2b(1) Tubing Hanger. The type of tubing threads on the hanger shall conform to API Specification 6A Section 902 or 918.

1002.2b(2) Running Tool. Tubing threads or tool joints, if used, shall be in conformance with API Specifications 5B or 7 or, the manufacturer's written specification. The tool should have adequate dimension for tonging.

NOTE: *The load capacity of the tool should not be inferred from the choice of end connections on the tools.*

1002.2c Vertical Bore. The minimum vertical bore with and without profiles shall comply with the manufacturer's written specification. The effect of wall thickness reduction due to plug profiles in the tubing hanger shall be included in the design analysis and documented as required in Section 300 of this specification. The tubing hanger bores shall be drifted in accordance with manufacturer's written specifications.

1002.2d Rated Working Pressure. The rated working pressure of the tubing hanger shall equal or exceed the maximum pressure which may be applied to the hanger body, tubing hanger lockdown, and tubing hanger annulus seal and the operating control pressure of the SCSSV. This rating shall be exclusive of the tubing connection(s) at the bottom of the hanger. The tubing hanger shall have a rated working pressure of either 5,000, 7,500, 10,000, 12,500, or 15,000 psi (34,5; 51,7; 69,0; 86,3; or 103,5 MPa).

NOTE: *This pressure rating requirement allows for possible leakage of pressure from the SCSSV control line into the annulus cavity above or below the tubing hanger.*

1002.2e SCSSV Control Line Stab Design. SCSSV control line stabs in the tubing hanger shall be designed so as to vent control pressure when the tree is removed. The SCSSV control stab should be designed to minimize seawater ingress when the tree is removed.

1002.3 MATERIALS. Materials used for tubing hanger systems shall comply with Section 400 of this specification. All metal to metal sealing surfaces in the production (injection) and annulus bores shall be either manufactured from, or inlayed with, corrosion resistant materials, with the exception of threads at the bottom of the tubing hanger.

1002.4 TESTING.

1002.4a Performance Verification Testing. Performance verification testing of the tubing hanger shall comply with Section 307 of this specification. In addition, the tubing hanger lockdown shall be tested to a minimum of 1.10 times the maximum rated working pressure from below.

1002.4b Factory Acceptance Testing.

1002.4b(1) Tubing Hanger. All tubing hangers shall be hydrostatically tested prior to shipment from the manufacturer's facility. The hydrostatic body test pressure shall be equal or greater than the rated working pressure.

Tubing hangers shall be tested to the requirements of API Specification 6A Section 605 except that they shall have a secondary holding period of a minimum of 15 minutes. In addition, the through bores (excluding tubing threads) of the tubing hanger shall be tested to at least 1.5 times the maximum rated working pressure.

A pup joint of tubing shall be installed on the hanger and the connection hydrostatic tested to manufacturer's written specifications.

Tubing hanger internal profiles shall be drifted and pressure tested with mating plug to the manufacturer's written specifications.

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

1002.4b(2) Tubing Hanger Running Tool. All wellbore pressure containing/controlling components shall comply with the hydrostatic test requirements of Section 600 of this specification with the exception that the through bores of the running tools shall be tested to a test pressure equal to at least 1.5 times the rated working pressure.

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

Components which contain hydraulic control fluid shall be subjected to a hydrostatic body/shell test per the requirements of Section 908.5b(3)(a) of this specification.

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

1002.5 WELDING. Welding for tubing hanger systems shall comply with Section 500 of this specification.

1002.6 MARKING. Tubing hanger systems shall be marked in accordance with Section 700 of this specification.

1002.7 STORING AND SHIPPING. Storing and shipping of tubing hanger systems shall comply with Section 800 of this specification.

SECTION 1100
MUDLINE EQUIPMENT — SPECIFIC REQUIREMENTS

1101 GENERAL.

1101.1 SCOPE. This section covers drilling and completion equipment used to suspend casing weight at or near the mudline, to provide pressure control, and to provide annulus access to the surface wellhead. Mudline equipment is used when drilling with a bottom supported rig or platform and provides for drilling, abandonment, platform and subsea tieback.

Mudline casing hangers, casing hanger running tools (landing subs), casing hanger landing rings, and tieback tools (tieback subs) are in fact an integral part of the casing strings. They are therefore specifically excluded from the design requirements and pressure rating methods assigned to like components in API Specifications 6A and 17D Section 1000, and specifically given the design requirements and stress allowables in Sections 1101 and 1102 of this document. These stress allowables are in keeping with current industry practice for safe working pressures for casing.

Mudline equipment typically involves proprietary profiles/configurations and/or API standard connections. The tools used for installation, retrieval, and testing are typically task specific and remotely operated.

The technical content of this section provides equipment specific requirements for performance, design, material, and testing. Specific mudline suspension equipment used during drilling and/or run as part of the casing string covered by this specification includes (see Figure 1100.1):

- Landing rings
- Casing hangers
- Casing hanger running tools (landing subs)
- Tieback tools (tieback subs)
- Abandonment caps

Mudline suspension equipment used during drilling and/or run as part of the casing string is designated "pressure controlling" equipment as defined in API Specification 6A. Quality control for these components shall be treated as "casing and tubing hanger mandrels" as set forth in Section 605.10 in API Specification 6A.

Specific mudline conversion equipment for subsea completions covered by this specification includes (see Figure 1100.1):

- Tieback adapters
- Tubing spools

Mudline conversion equipment shall be designated as either "pressure containing" or "pressure controlling" using the definitions set forth in Section 200 of API Specification 6A. Components designated as "pressure containing" shall be treated as "bodies" in API Specification 6A.

High pressure risers and accessory tools used with mudline equipment, such as brush and cleanout tools, cap running tools, etc., are beyond the scope of this specification.

Guidance systems that interface with a subsea BOP stack shall be designed, fabricated and tested in accordance with Section 1001.3 of this specification.

1101.2 DESIGN. The general design requirements for mudline equipment shall comply with Section 300 of this specification. If specific requirements for mudline equipment in this section differ from the general requirements stated in Section 300, these specific requirements shall take precedence.

1101.2a Rated Working Pressure. For each piece of mudline equipment, a rated working pressure shall be determined according to Table 1100.1 and Appendix E of this Specification or by proof testing per API Specification 6A, Section 303.3D.

The rated working pressure shall be inclusive of the pressure capacity of the end connections.

1101.2b Hanging/Running Capacity Rating.

1101.2b(1) Rating Running Capacity. A rated running capacity shall be determined for each piece of mudline suspension equipment in the load path between the top connection of the running tool and the lower connection of the hanger that is run as part of the casing string. The rated running capacity is defined as the maximum weight that can be run below the mudline component. Rated running capacity is not the same as joint strength, ultimate tensile strength or proof test load.

Rated running capacity includes the tension capacity of the threaded end connection that is machined into the mudline component and excludes thread pullout strength for the threaded end connection since pullout strength is a function of the weight and grade of casing that is threaded into the mudline component during use.

Primary membrane stresses in the body at the rated running capacity shall not exceed 80% of the minimum specified yield strength and shall be exclusive of internally applied pressure and externally applied global bending loads.

1101.2b(2) Rated Hanging Capacity. The rated hanging capacities shall be determined for each piece of mudline suspension equipment that hangs casing weight. The rated hanging capacity is defined as the maximum weight that can be suspended from the component at the rated location.

NOTE: *Different rated hanging capacities may be required for several locations on the component. For example, each external expanding latch or fixed landing ring and each internal latch profile or internal landing shoulder(s) shall have a rated hanging capacity.*

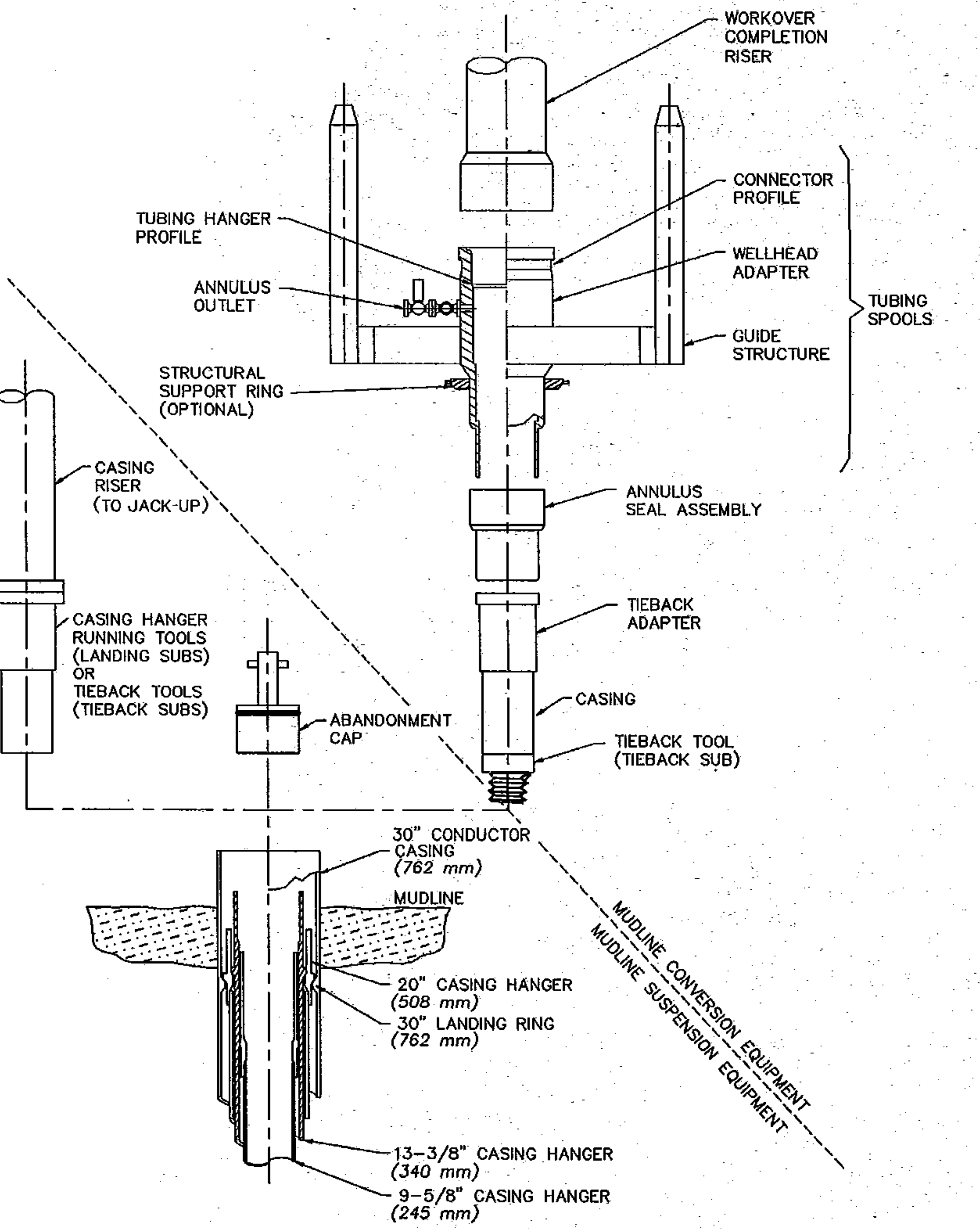


FIGURE 1100.1
TYPICAL MUDLINE EQUIPMENT COMPONENTS

Compressive stresses at load shoulders shall be permitted to exceed material yield strength at the rated hanging capacity provided that all other performance requirements are satisfied.

Rated hanging capacities shall include the effects of full rated working pressure. Both internal and external pressure shall be included. Primary membrane stresses in the body at the rated hanging capacities shall not exceed 80% of minimum specified yield strength.

Rated hanging capacities shall be documented by the manufacturer for a given set of nested equipment in an assembly or for each component individually.

1101.2c Outside and Inside Diameters. All mudline equipment minimum bores and maximum outside diameters will be minimum and maximum machining dimensions, respectively, and shall be stated in decimal form to the nearest 0.001 inch (0,02 mm). This requirement applies only to components which will pass through, or will have pass through them, other mudline components, tubulars or bits, etc. Outside dimensions shall exclude the expanded condition of expanding latches. These dimensions shall be documented by the manufacturer.

1101.2d Flowby Areas. Manufacturers shall document the minimum quantity flowby area provided for each design, including:

- flowby area while running through a specified weight of casing,
- flowby area when landed in a specified mudline component.

1101.2e Temperature Ratings. Each component shall have a Temperature Rating per Section 302.2.

1101.3 MATERIALS.

1101.3a General. Materials shall conform to the requirements of Section 400.

1101.3b Materials Classes.

NOTE TO USERS: *Appropriate materials classes for mudline equipment are AA or CC for general service, and DD or FF for sour service as defined by NACE and Section 302.3 of this specification.*

1101.3c NACE Requirements. For materials classes DD and FF (sour service), NACE MR-01-75 requirements shall be limited to the internal pressure containing and pressure controlling components, exposed to wellbore fluids. For example, sour service mudline hangers may include non-NACE external latch mechanisms and load rings.

1101.4 TESTING.

1101.4a Performance Verification Testing. Manufacturers are required to conduct and document performance verification testing results per Section 307 of this specification.

1101.4b Factory Acceptance Testing.

1101.4b(1) Hydrostatic Testing. Hydrostatic factory acceptance testing of mudline suspension equipment is not a requirement of this specification. If included in the manufacturer's written specification, then test pressures shall not exceed the Test Pressure as determined in Appendix E.

Hydrostatic factory acceptance testing of mudline conversion equipment is mandatory and shall be tested in accordance to Section 605 of this specification.

1101.4b(2) Drift Testing. Drift testing is not a requirement of this specification. If drift testing is included in the manufacturer's written specification, then the requirement of API Specification 5CT, Section 6 shall be followed. The drift test may specify either individual component drift testing or assembly drift testing (i.e., hanger, running tool, and casing pups assembled together).

TABLE 1100.1
MAXIMUM ALLOWABLE STRESS DUE TO PRESSURE*
(For Mudline Equipment Only)

Rated Working Pressure		Test Pressure
Suspension Equipment	Conversion Equipment	Suspension & Conversion
Membrane Stress = S_m (Where $S_m + S_b \leq 1.0$)		
0.8 S_{yld}	0.67 S_{yld}	0.9 S_{yld}
Membrane + Bending = $S_m + S_b$ (Where $S_m \leq 0.67$ Yield)		
1.2 S_{yld}	1.0 S_{yld}	1.35 S_{yld}
(Where $S_m \geq 0.67$ Yield or ≤ 0.9 Yield)		
2.004 S_{yld}-1.2S_m	N/A	2.15 S_{yld}-1.2 S_m

*NOTE 1: *Stresses given in this Table shall be determined in accordance with the definitions and methods presented in Appendix E of this specification. The designer shall consider the effects of stresses beyond the yield point on non-integral connections such as threaded connections and latch profiles, where progressive distortion can result.*

NOTE 2: *Bending stresses in this method are limited to lower values than are permitted by the ASME method for secondary stresses since this is a limit-based method with inherently higher safety margins. An alternative method is included in Appendix E of this specification to permit higher secondary stresses while controlling membrane stresses to traditional, more conservative limits.*

1101.4b(3) Stack-up and Fit Test. Stack-up and fit test is not required by this specification. If stack-up and fit test is part of the manufacturer's written specification, then the manufacturer shall document the requirements for measuring and/or recording axial and drift dimensions to be taken to verify proper stack-up.

1101.5 WELDING. Welding shall comply with Section 500 of this specification.

1101.6 MARKING AND DOCUMENTATION. All mudline equipment shall be stamped with at least the following information:

- Manufacture Name or Trademark
- Nominal Size

- Assembly Serial Number (if applicable)
- Part Number and Revision
- Material Class

The following information shall be either stamped on the equipment or provided in system documentation as applicable:

- Rated Working Pressure
- Rated Running Capacity
- Rated Hanging Capacity
- Minimum Flowby Area
- Maximum Particle Size
- Drift Diameter
- Maximum Allowable Test Pressure

In addition to the above requirements, mudline conversion equipment shall be stamped in accordance with Section 700 of this specification.

1101.7 STORING AND SHIPPING. Storing and shipping shall comply with Section 800 of this specification.

1102 MUDLINE SUSPENSION EQUIPMENT.

1102.1 LANDING/ELEVATION RING.

1102.1a Description. The landing/elevation ring is an internal upset located at or near the mudline to provide an internal landing shoulder for supporting all combined casing loads. The following considerations shall be addressed when generating designs and technical specifications for the landing elevation ring:

- shoulder load bearing strength
- completion elevation above mudline
- centralization of casing hangers
- mud and cement return flowby area

1102.1b Design. The following criteria shall be considered and documented by the manufacturer when designing the landing/elevation ring:

- structural loads (including casing hanging loads)
- dimensional compatibility with other hangers
- dimensional compatibility with specified bit program
- welding requirements
- mud flowby requirements

NOTE TO USERS: *The minimum ID of each ring should be selected to allow both the landing of subsequent casing hangers and the passage bit sizes to be used.*

1102.1c Documentation. The manufacturer shall document any critical alignment and/or welding requirements for attachment of the landing/elevation ring to the conductor pipe.

1102.2 CASING HANGERS.

1102.2a Description. Mudline casing hangers typically provide the following functions and features within the mudline suspension system:

- support casing weight at mudline
- support casing weight of subsequent strings
- allow annulus access to the surface wellhead
- allow for mud/cement flowby while running and landing in previous hanger, and
- allow attachment of running tool, tieback riser sub and/or subsea conversion equipment
- provide for reciprocating the casing string during cementing operations

1102.2a(1) End Connections. The casing hanger and running tool are normally installed with casing extensions made up to both ends. Normally the running tool (landing sub) extension will have a pin-by-box casing nipple extension, and the casing hanger will have a pin-by-pin casing extension. The assembly of casing extensions, running tool and casing hanger should be done prior to shipment to the rig. This allows the casing hanger assembly to be handled and run just as another piece of casing.

1102.2a(2) Landing Shoulders. Landing shoulders on casing hangers are typically one of two following types:

- fixed support rings
- nonfixed, or expanding/contracting latch rings

The fixed support ring lands on a beveled landing shoulder (usually 45 degrees) in the landing ring or previous casing hanger. Flowby porting for mud and cement passage and adequate bearing capacity is maintained on this landing ring.

The nonfixed support ring has an expanding/contracting latching load ring which locates in the appropriate landing groove. In some cases during cementing operations, the casing is reciprocated a short distance above the hanger seat. Therefore, the nonfixed landing rings typically do not have permanent lockdown mechanisms.

1102.2a(3) Internal Profiles. The internal profiles of mudline casing hangers serve these functions:

- lock and seal running tool (landing sub) and tieback adapters
- seat subsequent casing hangers, and
- seat tubing hanger (optional)

The lock and seal mechanism for the running tool and tieback adapters is usually the upper internal profile of the mudline casing hanger. The locking profile may be a thread or an internal locking groove for a cam-actuated locking mechanism. The running tool is usually designed to release with right-hand rotation.

Wash ports may be incorporated as necessary into each landing sub or casing hanger to give a washout flow rate, without cutting out the port area. After the casing hanger has been landed and cemented, the wash ports are opened. After flushing out the casing riser annulus, the wash ports are closed. The purpose of washing out the casing riser area is to ensure that excessive cement has been removed from the casing hanger/running tool connection area.

1102.2b Design.

1102.2b(1) Loads. The following loads shall be considered and documented by the manufacturer when designing mudline system casing hangers:

- Casing Loads
- Pressure
- Operating Torque

1102.2b(2) Flowby Area. Casing hanger minimum flowby areas shall be documented by the manufacturer for each casing hanger design configuration.

1102.2b(3) Particle Size. Maximum particle size shall be documented for each casing hanger design configuration.

1102.2b(4) End Connections. Standard API or other end connections provided on the casing hanger and running tool (landing sub) shall comply with the requirements of Sections 901 thru 906 of this specification.

Adequate surface areas for tongs should be provided for installing casing into the casing hanger and running tool (landing sub).

1102.3 CASING HANGER RUNNING AND TIEBACK TOOLS.

1102.3a Description. Casing hanger running tools shall be designed to provide a reversible connection between the mudline hanger and the casing riser used for drilling operations. They may be either threaded (including optional weight set) or cam-actuated tools as supplied by each individual manufacturer. Threaded running tools engage directly into the casing hanger. Cam-actuated tools engage in an internal locking groove inside of the casing hanger. Wash ports may be provided in the casing hanger or landing sub to allow for cleaning of cement from around the previously run hanger/landing sub connection.

Casing hanger tieback tools (tieback subs) are used to connect tieback adaptors to mudline suspension wellhead equipment for subsea completion purposes. The requirements for tieback tools shall be the same as those for casing hanger running tools.

1102.3b Design.

1102.3b(1) Loads. As a minimum, the following loads shall be considered and documented by the manufacturer when designing the running tools:

- Suspended Weight
- Pressure Loads
- Torque
- Overpull
- Environmental Loads

1102.3b(2) Threaded Running and Tieback Tools. Threaded running tools shall be right-hand release. Threaded tieback tools and tieback profiles shall be right-hand make-up.

1102.4 ABANDONMENT CAPS.

1102.4a Description. Abandonment caps typically are used during temporary abandonment and protect internal hanger profiles, threads, and seal areas from marine growth, mechanical damage, and debris.

1102.4b Design. Pressure and any external loads applied during installation, pressure relief, and retrieval shall be considered and documented by the manufacturer in the design of abandonment caps. Abandonment caps shall be equipped with a means of relieving pressure prior to removal.

1103 MUDLINE CONVERSION EQUIPMENT FOR SUBSEA COMPLETIONS.

1103.1 TIEBACK ADAPTERS.

1103.1a Description. Tieback adapters provide the interface between mudline suspension equipment and subsea completion equipment (see Figure 1100.1).

1103.1b Design. Tieback adapters typically provide structural support and pressure control for preparing a well drilled with mudline hangers for a subsea completion.

One or more seals shall be provided between production casing tieback adapter and the tubing hanger spool.

Tieback adapters should provide structural integrity to transfer applied loads to the surface casing or conductor pipe.

1103.2 TUBING HANGER SPOOLS. The tubing hanger spool is attached to a tieback adapter on the lower end and to the tree on the upper end. The spool houses the tubing hanger/wear bushing and may provide an annulus access connection.

All design, materials, and testing shall be in accordance with Section 907 of this specification.

1103.3 TUBING HANGER SYSTEM. All design, material and testing of the tubing hanger system shall be in accordance with Section 1002 of this specification.

APPENDIX A
PURCHASING GUIDELINES

A1 GENERAL. This appendix provides recommended guidelines for inquiry and purchase of API Specification 17D equipment.

A2 TYPICAL WELLHEAD AND TREE CONFIGURATIONS. Examples of typical wellhead and tree configurations are shown in Figures 102.1 through 102.5.

A3 PRODUCT SPECIFICATION LEVELS. Product specification levels are defined in Section 103 of this specification.

Product specification levels apply to all pressure containing and pressure controlling parts.

Determination of the production specification level is the responsibility of the purchaser. PSL 3 equipment is recommended for sour service with working pressures above 5,000 psi, and for non-sour service with working pressures above 10,000 psi.

A4 MATERIALS CLASS RATING. Materials Class Rating shall be determined per Appendix A of API Specification 6A, using the following Table A1 in place of Table A1 of Section A7 of Appendix A of API Specification 6A.

TABLE A1

RETAINED FLUIDS	RELATIVE CORROSIVITY OF RETAINED FLUID	PARTIAL PRESSURE OF CO_2 (psia) (MPa)	RECOMMENDED MATERIALS CLASS*
General Service	Noncorrosive	<7 (0,05)	AA
General Service	Slightly corrosive	7 to 30 (0,05 to 0,21)	BB
General Service	Moderately to highly corrosive	>30 (0,21)	CC
Sour Service	Noncorrosive	<7 (0,05)	DD
Sour Service	Slightly corrosive	7 to 30 (0,05 to 0,21)	EE
Sour Service	Moderately to highly corrosive	>30 (0,21)	FF
Sour Service	Very corrosive	>30 (0,21)	HH

*As defined in Table 302.3 of API Specification 6A.

APPENDIX B
METRIC CONVERSION RULES

SECTION B100
METRIC DATA — GENERAL INFORMATION

B101 PURPOSE.

B101.1 Purpose. The purpose of this appendix is to document rules that have been used to provide metric dimensions and data. The dimensions obtained by application of the conversion rules in this appendix are different from the results that would be obtained by exact conversion of the dimensions in this specification.

B102 CONVERSION RULES. Dimensions are converted in the following manner:

B102.1 Convert first from decimal inch to exact fraction. This is done to account for the fact that API designs originated in the fractional inch system. Therefore, a dimension of 4.31 in the tables actually means 4-5/16 or 4.3125".

B102.2 Then multiply the resulting exact decimal equivalent of the fractional-inch dimension by 25,4 mm to obtain the exact millimeter dimension.

Example: 4.3125" = 109,5375 mm. Note that the comma is used as a decimal marker for metric data.

B102.3 Then do the rounding indicated for the particular dimension. Rounding rules differ for different dimensions, depending on the function of the dimension.

For example, if the above dimension were to be rounded to the nearest even 5 mm, the resulting dimension would be 110 mm.

B102.4 In summary, the conversion is in three steps, as follows: 431"-> 4.3125"-> 109,5375 mm - > 110 mm.

SECTION B200
API FLANGES

B201 PRESSURE RATINGS.

B201.1 Pressures. Pressure ratings are given in MPa. These units were selected instead of the bar, for three reasons: the size of these units is more convenient for the high pressures encountered in the oilfield; the MPa is a true SI unit; and the MPa is exactly one Newton per square mm, making it consistent with the units for force and length and eliminating the need for conversion for calculations. This puts pressures in the same units as commonly used for material strengths.

B201.2 Ratings. The selected ratings have been rounded in such a way as to preserve the ratio pressure ratings, while still using conveniently simple numbers. Thus 1.5 x 13,8 = 20,7. Equivalent ratings are:

2,000 psi	13,8 MPa
3,000 psi	20,7 MPa
5,000 psi	34,5 MPa
10,000 psi	69,0 MPa
15,000 psi	103,5 MPa
20,000 psi	138,0 MPa

B202 NOMINAL SIZES.

B202.1 Nominal bore sizes. Nominal sizes for API flanges are to be rounded to the nearest mm in metric sizes. Thus, the following sizes are equivalent:

NOMINAL SIZES in	mm	NOMINAL SIZES in	mm
1-13/16	46	11	279
2-1/16	52	13-5/8	346
2-9/16	65	16-3/4	425
3-1/16 or 3-1/18	78	18-3/4	476
4-1/16	103	20-3/4	527
5-1/8	130	21-1/4	540
7-1/16	179	26-3/4	680
9	228	30	762

B202.2 Nominal tube and casing sizes. Nominal sizes for tubing and casing are to be rounded to the nearest mm in inch sizes. Thus the following are equivalent:

NOMINAL SIZES in	mm	NOMINAL SIZES in	mm
2-3/8	60	7-5/8	194
2-7/8	73	8-5/8	219
3-1/2	89	9-5/8	244
4	102	10-3/4	273
4-1/2	114	11-3/4	298
5	127	13-3/8	340
5-1/2	140	16	406
6-5/8	168	18-5/8	473
7	178	20	508

B203 FLANGE DIMENSIONS.

B203.1 Interchangeability. The design of API flanges is based on the design of ANSI B16.5 flanges. This common set of dimensions permits some interchangeability between the two designs when ring joint flanges are used on the corresponding ANSI flanges. For this reason it was decided to preserve this interchangeability by considering the previously published ANSI metric flange dimensions when establishing the API metric sizes. This resulted in slightly different bolt hole sizes than would result from using the rounding rules below, since the metric ANSI flanges are usable with metric fasteners. Other dimensions were rounded using the rules below, resulting in slightly more accurate flange thickness and bolt circle dimensions, but which are well within the tolerance range of the previously published ANSI B16.5 dimensions.

B204 FASTENERS.

B204.1 Sizes. The metric flanges are to be used with inch size fasteners. Adoption of metric fasteners on

API flanges is not practical due to the compact design of the flanges and due to the fact that metric fasteners with equivalent strength are slightly larger than inch size fasteners. The use of metric fasteners on API flanges, while permitted by the dimensions, is not encouraged due to the general unavailability of metric fasteners to the special API strength and hardness requirements.

B205 ROUNDING RULES. The following rules were used to develop flange dimensions:

B205.1 Maximum bore: round to the nearest 0,1 mm.

Example: 209" - > 2.09375" - > 53,18125 mm - > 53,2 mm.

B205.2 Flange O.D.: round to the nearest 5 mm. This is consistent with ANSI practice.

Example: 8.12" - > 8.125" - > 206,375 mm - > 205 mm.

Tolerance: 0.06" becomes 2 mm; 0.12", 3 mm.

B205.3 Maximum chamfer: 0.12" becomes 3 mm; 0.25", 6 mm.

B205.4 Raised face diameter: round to nearest 1 mm. Tolerance 1 mm.

B205.5 Thickness of flange: round up to next 0,1 mm.

Tolerance: + 3 mm.

B205.6 J1, J2, and J3 dimensions: round to nearest 0,1 mm.

Tolerance on J1, -3 mm.

B205.7 Radius at back face, convert as follows:

.38 in	10 mm
.62 in	16 mm
.75 in	19 mm
.81 in	21 mm
1.00 in	25 mm

B205.8 Bolt hole location tolerance, 0,8 mm.

B205.9 Bolt circle: round to nearest 0,1 mm.

B205.10 Bolt hole diameter: round up to next even mm.

Tolerance: up through 42 mm holes, -0.5 mm, + 2 mm
over 42 mm holes, -0,5 mm, +3 mm.

B205.11 Stud lengths: Recalculate in metric units and round to nearest 5 mm.

B205.12 Segmented flange dimensions:

E dimension: round to nearest 0,1 mm.

F dimension: 0.12 becomes 3 mm.

K dimension: round to nearest 0,1 mm.
tolerance: -0, +0,5 mm.

Q dimension: nearest 0,01 mm.
tolerance, +0,25 mm

B205.13 Rough machine dimensions for inlaid ring grooves: round all dimensions up to the nearest 0,5 mm; tolerance, +1 mm.

B205.14 Ring gasket and groove dimensions: Convert exactly to the nearest 0,01 mm, as in the Fourteenth Edition of API 6A.

SECTION B300
OTHER EQUIPMENT DIMENSIONS

B301 VALVE END-TO-END DIMENSIONS.

B301.1 Interchangeability. For all valves having corresponding end-to-end dimensions in ANSI Specification B16.34, Steel valves, the ANSI B16.34 metric dimension shall be used. For all other valves, the dimension shall be rounded to the nearest 1 mm, with a tolerance of 2 mm.

B302 CROSS AND TEE CENTER-TO-END DIMENSIONS. These dimensions shall be rounded to the nearest 0.5 mm with a tolerance of 1 mm.

B303 MULTIPLE COMPLETION CENTERLINE SPACING. These dimensions shall be converted and expressed to two decimals. The resulting dimension and tolerance shall be selected so that the physical size will always be within the present tolerance range of ±0.005" when a tolerance of 0,12 mm is applied.

Example: Present dimension, 1.390 from flange center ±.005.

		Alternatives
Lower limit	1.385 - > 35,179 mm	(35,18 or 35,19)
Center	1.390 - > 35,306 mm	(35,30 or 35,31)
Upper limit	1.395 - > 35,433 mm	(35,42 or 35,43)

Choose the first center dimension, 35,30 since it is a round number.

SECTION B400
CONVERSION FACTORS

B401 LENGTH.

1 in	=	25,4 mm (exactly)

B402 PRESSURE/STRESS.

1 lb/in (psi)	=	0,006894757 MPa
1 Mega Pascal (MPa)	=	1 N/mm^2

B403 IMPACT ENERGY.

1 ft-lb	=	1,355818 Joule (J)

B404 TORQUE.

1 ft-lb	=	1,355818 N•m (Newton-meter)

B405 TEMPERATURE.

°Celsius	=	5/9 (°Fahrenheit-32)

B406 FORCE.

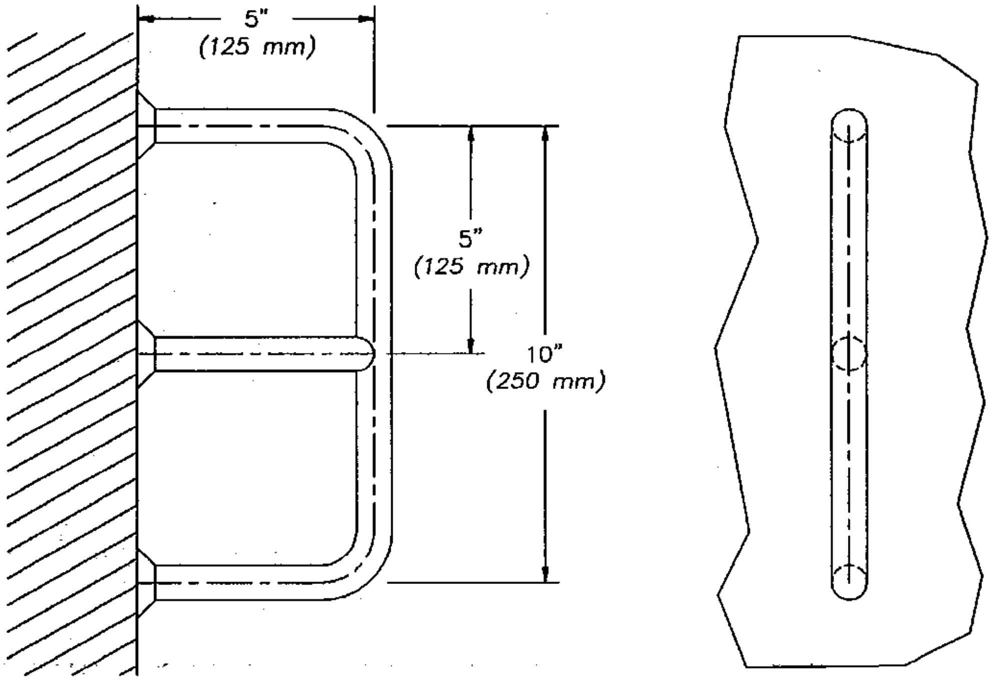
1 lbf	=	4,44823 Newton (N)

B407 MASS.

1 lbm	=	0,4535924 kilogram (kg)

APPENDIX C
CANDIDATE API STANDARD INTERVENTION FIXTURES

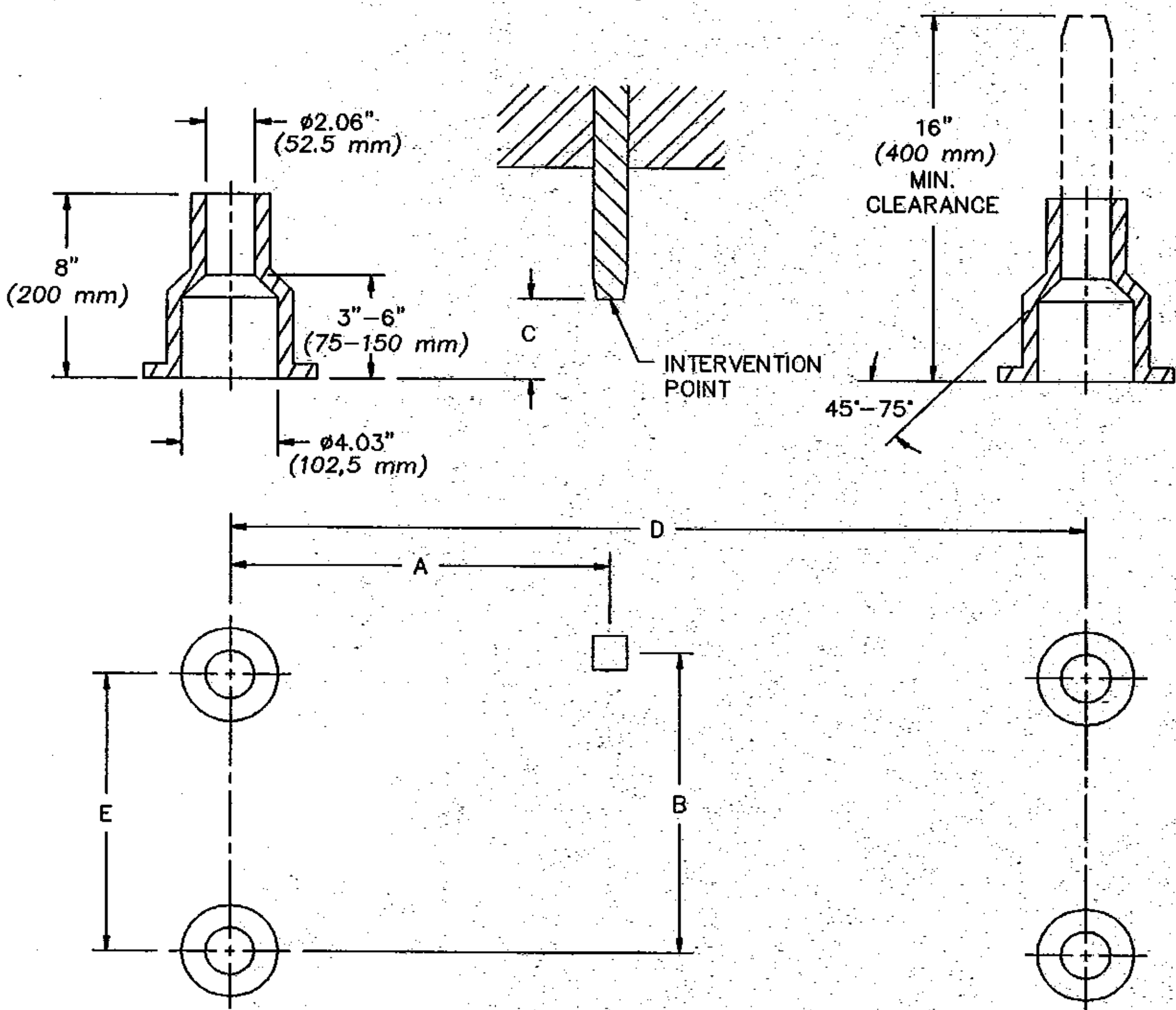
Description	Figure Number
• Grasping	C921.1
• Docking	C921.2
• Docking	C921.3
• Linear/Rotary	C921.4
• Linear	C921.5
• Rotary	C921.6
• Rotary/Fluid Coupling	C921.7
• Docking/Rotary/Fluid Coupling	C921.8
• Docking/Rotary	C921.9
• Fluid Coupling	C921.10
• Fluid Coupling	C921.11



NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
   TOLERANCES ARE AS FOLLOWS:
   - 3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   - 2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   - FRACTION – ±1/16 (± 1 mm)
2. MATERIAL 3/4" (20 mm) DIA BAR STOCK, 36,000 PSI (250 MPa) MIN. YIELD STRENGTH.
3. LOAD CAPACITY OF COMPOSITE FIXTURE IS 500 LBS (2200 N). GRIPPING, BENDING AND END LOAD, FROM ANY DIRECTION.
4. METHOD OF ATTACHMENT OPTIONAL.

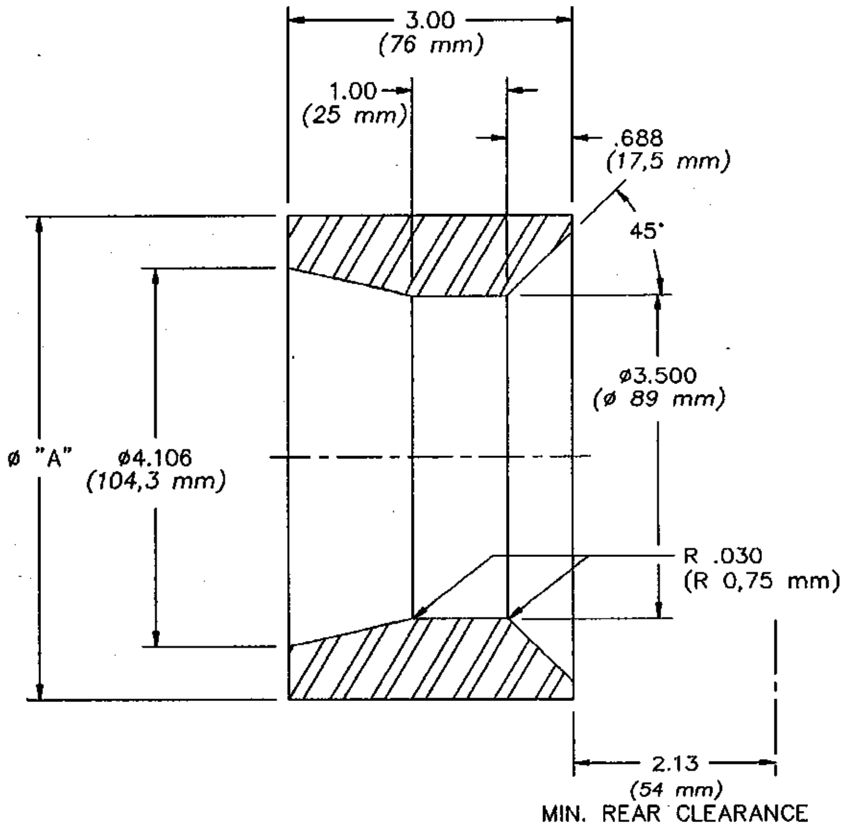
FIGURE C921.1
INTERVENTION FIXTURE GRASPING



NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED. TOLERANCES ARE AS FOLLOWS:
   - 3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   - 2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   - FRACTION – ±1/16 (± 1 mm)
2. "D" DIMENSION IS 24"–60" (6" INCREMENTS) (610–1525 mm)(150 mm INCREMENTS)
3. "C" DIMENSION SHALL BE BETWEEN 6"& 24" (150 & 610 mm)
4. "E" DIMENSION IS OPTIONAL AND MAY BE REPEATED
5. "A" AND "B" DIMENSIONS SHALL BE SPECIFIED BASED ON INTERVENTION TOOL REQUIREMENTS.
6. MATL. IS 36,000 PSI MIN. YIELD (250 MPa)
7. LOAD CAPACITY BASED ON INTERVENTION TOOL FULLY ENGAGED IN BOTH RECEPTACLES

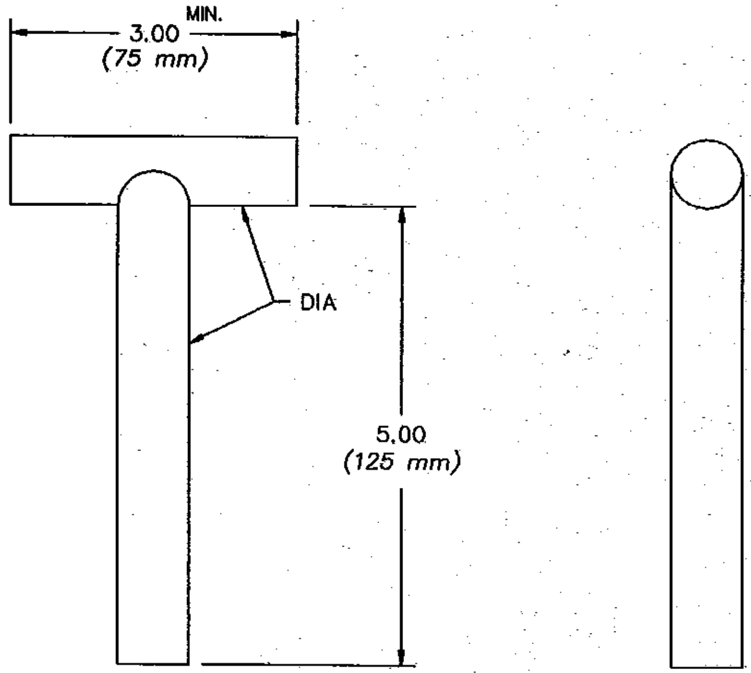
FIGURE C921.2
INTERVENTION FIXTURE DOCKING



NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED. TOLERANCES ARE AS FOLLOWS:
   - 3 PLACE DECIMAL....±.01 (±0,2mm)
   - 2 PLACE DECIMAL...±.03 (±0,5 mm)
2. "A" DIMENSION IS NO LESS THAN 5" (125 mm).
3. MATERIAL MINIMUM YIELD IS 36,000 PSI (250 MPa).

FIGURE C921.3
INTERVENTION FIXTURE DOCKING



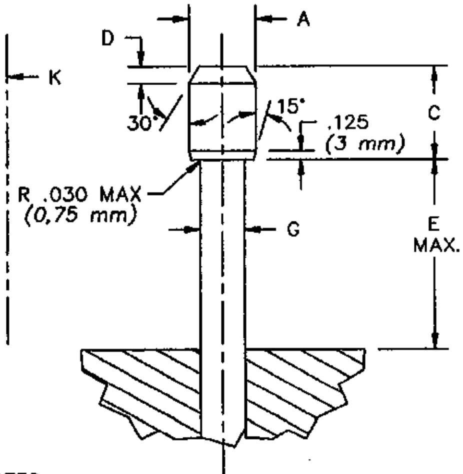
	CLASS 1	CLASS 2
DIA. INCH	.75	1.25
DIA. (mm)	*(20)*	*(30)*

NOTES:

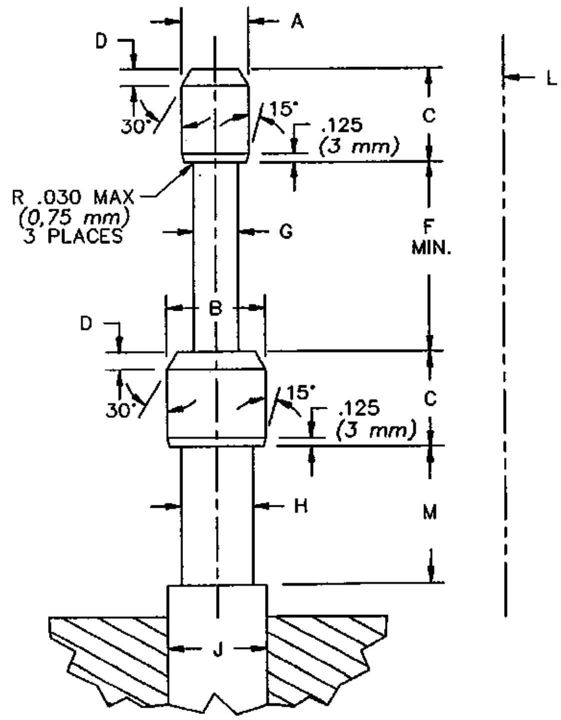
1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
   TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   FRACTION – ±1/16 (± 1 mm)
2. MATERIAL IS 75,000 PSI (520 MPa) MIN. YIELD STRENGTH.

FIGURE C921.4
INTERVENTION FIXTURE LINEAR/ROTARY

PULL ONLY PROFILE



PUSH & PULL PROFILE



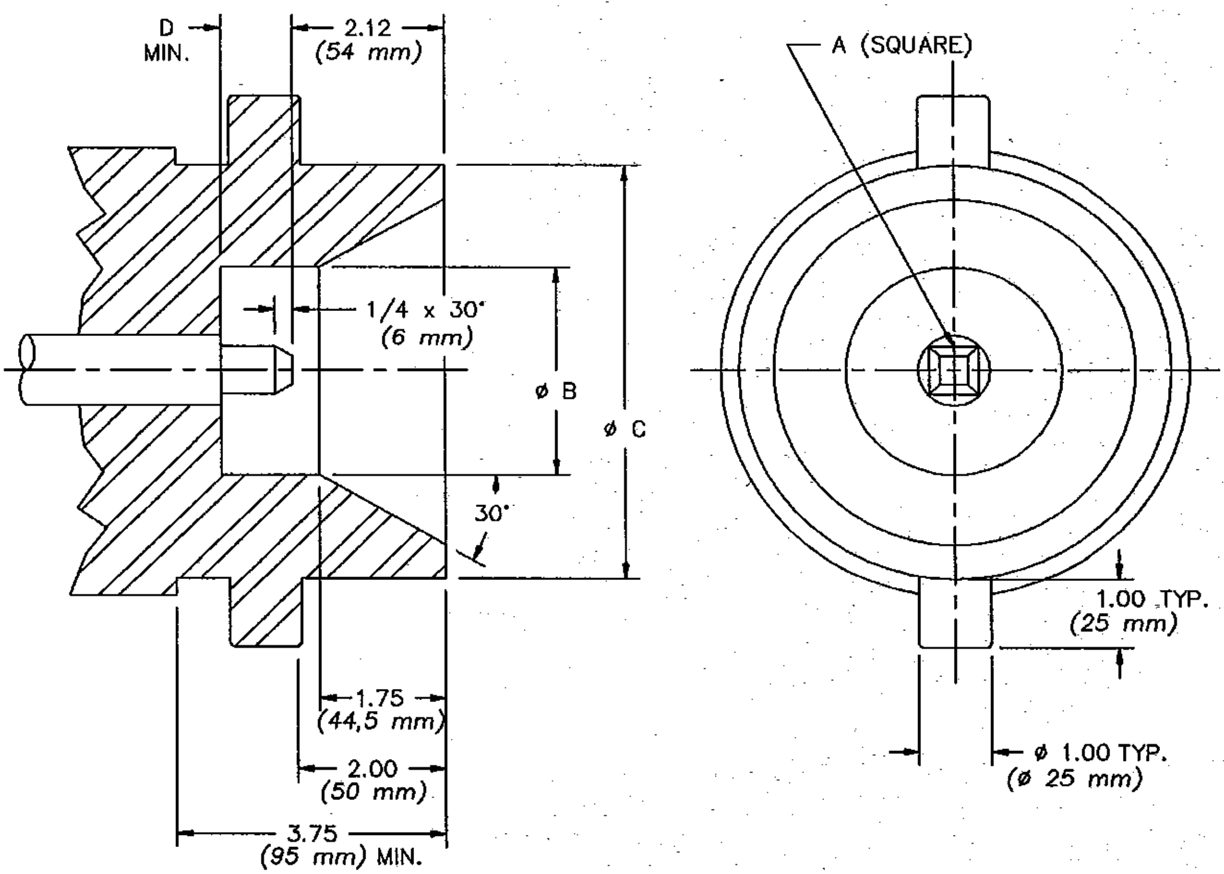
NOTES:

1. ALL DIMENSION ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED. TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (±0,5 mm)
   1 PLACE DECIMAL – ±.06 (± 1 mm)
2. MINIMUM RADIAL SIDE AND BOTTOM CLEARANCE AROUND PROFILE FOR TOOLING.
3. RADIAL TOP CLEARANCE ABOVE PROFILE FOR TOOLING. THE WIDTH OF THE TOP CLEARANCE WILL MATCH THE WIDTH OF THE CLEARANCE AROUND THE PROFILE.
4. MATERIAL IS 75,000 PSI (520 MPa) MIN. YIELD STRENGTH.
5. MAXIMUM EFFECTIVE STROKE = F – E

DIMENSIONS IN INCHES		CLASS			
		5	6	7	8
DIMENSIONS	øA	.937	1.625	2.750	4.500
	øB	1.375	2.375	4.000	6.000
	C	1.37	1.75	2.50	3.75
	D	.25	.50	.75	1.00
	E	5.75	9.00	15.00	24.00
	F	.75	3.00	4.00	5.00
	øG	.625	1.000	1.750	3.000
	øH	1.000	1.750	3.000	4.500
	øJ	1.375	2.375	4.000	6.000
	K (2)	3.00	4.00	5.00	6.00
	L (2)	4.00	5.00	5.00	6.00
	M	2.00	3.00	4.00	5.00

DIMENSIONS IN mm		CLASS			
		5	6	7	8
DIMENSIONS	øA	23,8	41,3	69,9	114,3
	øB	34,9	60,3	101,6	152,4
	C	35	44,5	63,5	95,5
	D	6,5	12,5	19	25,5
	E	146	228,5	381	609,5
	F	19	76	101,5	127
	øG	15,9	25,4	44,5	76,2
	øH	25,4	44,5	76,2	114,3
	øJ	34,9	60,3	101,6	152,4
	K (2)	76	101,5	127	152,5
	L (2)	101,5	127	127	152,5
	M	51	76	101,5	127

FIGURE C921.5
INTERVENTION FIXTURE LINEAR



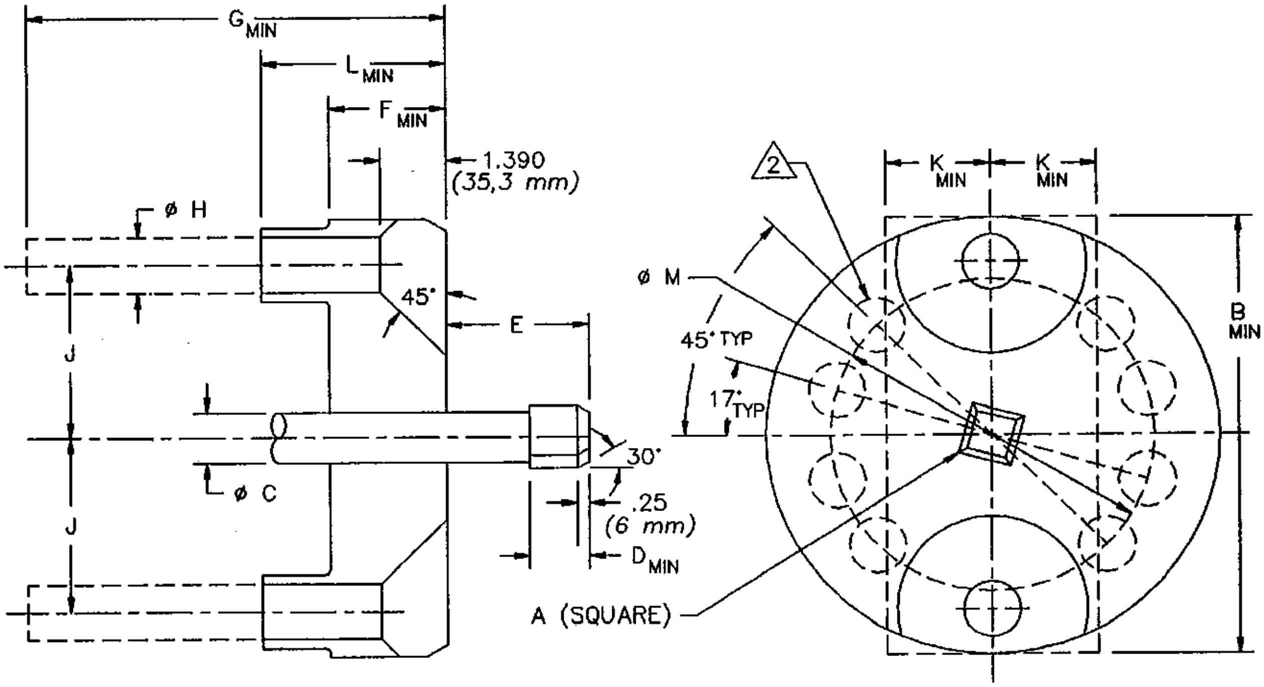
NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
   TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   FRACTION – ±1/16 (± 1 mm)
2. MATERIAL IS 75,000 PSI (520 MPa) MIN. YIELD STRENGTH.

DIMENSIONS IN INCHES		CLASS				
		2	3	4	5	6
DIM	A	.687	1.125	1.500	2.000	2.500
	øB	3.00	5.00	5.00	6.00	6.00
	øC	6.00	8.00	8.00	9.00	9.00
	D	1.00	1.25	2.00	2.50	3.12

DIMENSIONS IN mm		CLASS				
		2	3	4	5	6
DIM	A	17,4	28,6	38,1	50,8	63,5
	øB	76	127	127	152,5	152,5
	øC	152,5	203	203	228,5	228,5
	D	25,5	32	51	63,5	79

FIGURE C921.6
INTERVENTION FIXTURE ROTARY



DIMENSIONS IN INCHES		CLASS 2	CLASS 3
DIMENSIONS	A	.680 /.670	1.125 /1.115
	B	6.47	9.47
	C	.670	1.115
	D	1.000	1.250
	E	2.25 /1.00	3.00 /1.25
	F	1.50	2.45
	G	8.50	8.75
	H	.812	1.187
	J	2.500	3.750
	K	1.97	2.20
	L	3.25	3.87
	øM	–	6.750

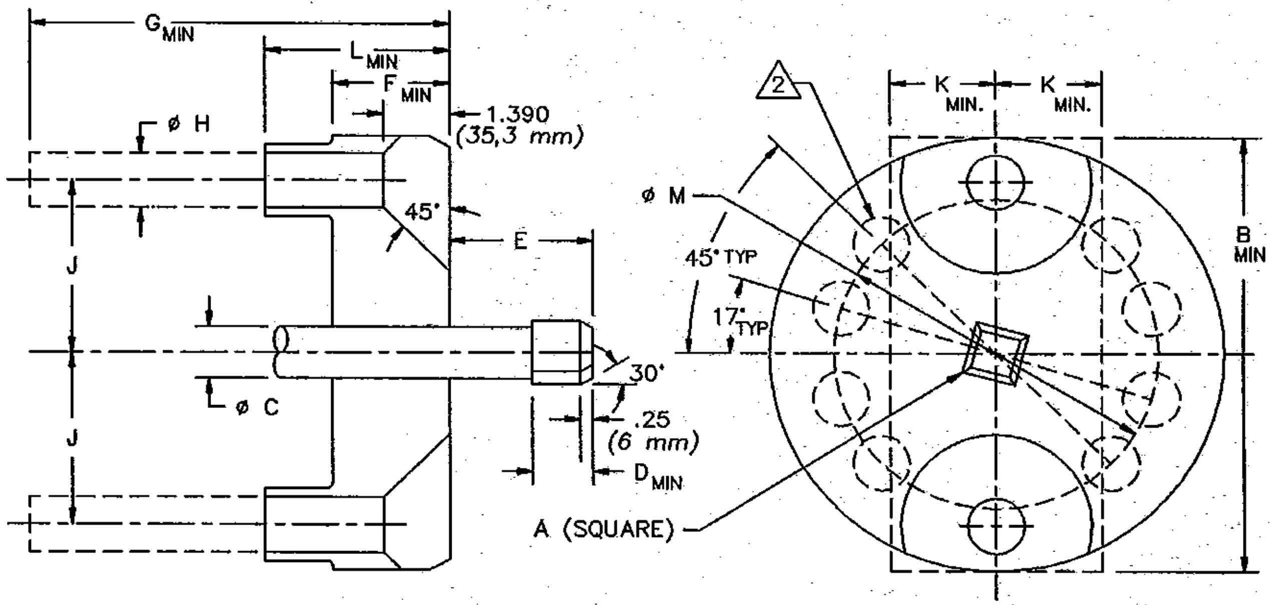
DIMENSIONS IN mm		CLASS 2	CLASS 3
DIMENSIONS	A	17,3 /17,0	28,6 /28,3
	B	164,5	240,5
	C	17,0	28,3
	D	25,4	31,8
	E	57 /25,5	76 /32
	F	12,5	62
	G	216	222
	H	20,6	30,2
	J	63,5	95,2
	K	50	56
	L	82,5	98,5
	øM	–	171,5

NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
   TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   FRACTION – ±1/16 (± 1 mm)

2. FLUID COUPLINGS ARE OPTIONAL UP TO 8 PLACES AS REQUIRED.
   FOR CLASS 3 USE FIGURE 921.10 SIZE 1-3/8" (35 mm).

FIGURE C921.7
INTERVENTION FIXTURE ROTARY/FLUID COUPLING



NOTES:

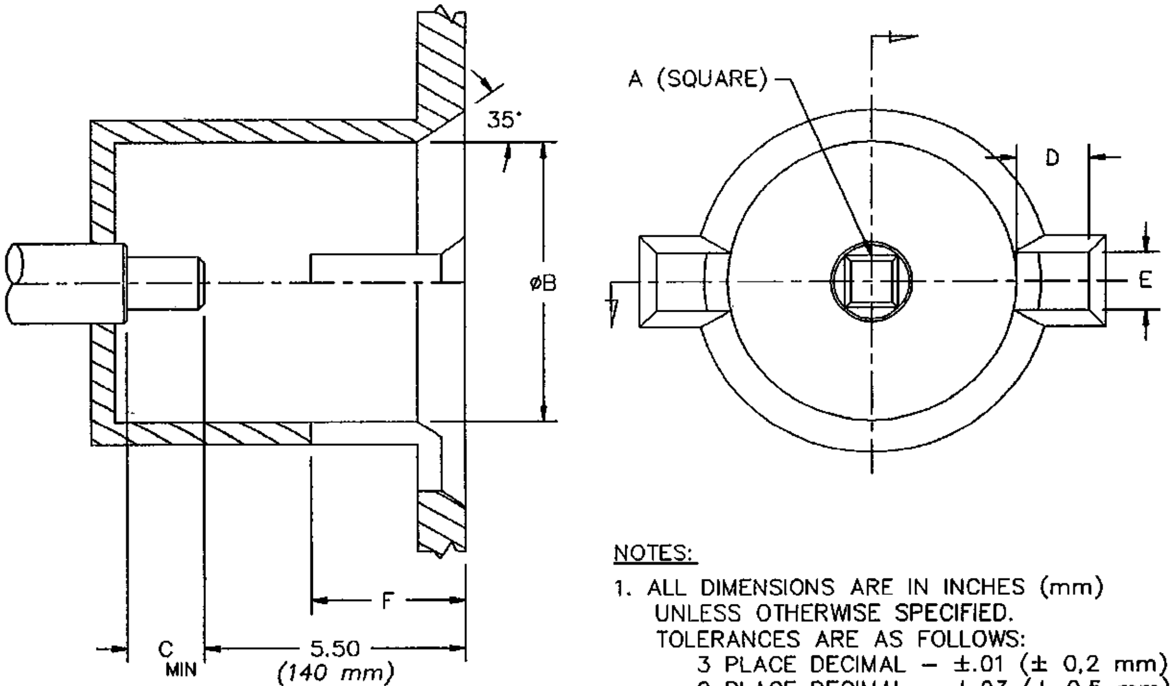
1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED. TOLERANCES ARE AS FOLLOWS:
   - 3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   - 2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   - FRACTION – ±1/16 (± 1 mm)

2. FLUID COUPLINGS ARE OPTIONAL UP TO 8 PLACES AS REQUIRED. FOR CLASS 4 AND 5 USE FIGURE 921.10 SIZE 1-3/8" (35 mm).

DIMENSIONS IN INCHES		CLASS 4	CLASS 5	CLASS 6	CLASS 7
DIMENSIONS	A	1.500 /1.490	2.000 /1.990	2.625 /2.615	3.500 /3.490
	B	13.47	13.47	16.97	16.97
	C	1.490	1.990	2.615	3.490
	D	2.000	2.500	3.125	4.500
	E	4.00 /2.00	5.00 /2.50	6.50 /3.50	8.00 /4.00
	F	3.45	3.45	4.45	4.45
	G	9.75	9.75	10.50	10.50
	H	1.937	1.937	2.570	2.570
	J	5.500	5.500	6.750	6.750
	K	2.72	2.72	3.47	3.47
	L	5.28	5.28	6.53	6.53
	øM	6.750	6.750	–	–

DIMENSIONS IN mm		CLASS 4	CLASS 5	CLASS 6	CLASS 7
DIMENSIONS	A	38,1 /37,8	50,8 /50,5	66,7 /66,4	88,9 /88,6
	B	342	342	431	431
	C	37,8	50,5	66,4	88,6
	D	50,8	63,5	79,4	114,3
	E	101,5 /51	127 /63,5	165 /89	203 /101,5
	F	87,5	87,5	113	113
	G	247,5	247,5	266,5	266,5
	H	49,2	49,2	65,3	65,3
	J	139,7	139,7	171,5	171,5
	K	69	69	88	88
	L	134	134	166	166
	øM	171,5	171,5	–	–

FIGURE C921.8
INTERVENTION FIXTURE
DOCKING/ROTARY/FLUID COUPLING



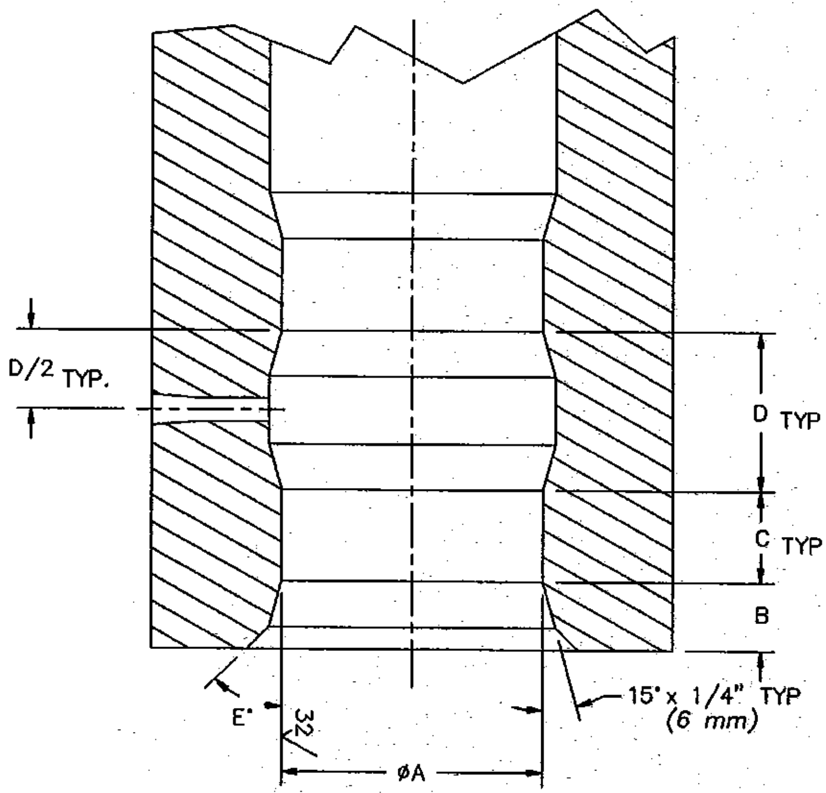
NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
   TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   FRACTION – ±1/16 (± 1 mm)

DIMENSIONS IN INCHES		CLASS						
		1	2	3	4	5	6	7
DIMENSIONS	A	.687	.687	1.125	1.500	2.000	2.625	3.500
	øB	6.06	6.06	6.06	6.06	7.50	9.56	9.56
	C	1.62	1.62	1.62	1.62	2.50	3.50	3.50
	D	1.50	1.50	1.50	1.50	2.25	3.25	3.25
	E	1.25	1.25	1.25	1.25	1.50	1.75	1.75
	F	3.25	3.25	3.25	3.25	5.00	7.00	7.00

DIMENSIONS IN mm		CLASS						
		1	2	3	4	5	6	7
DIMENSIONS	A	17,5	17,5	28,6	38,1	50,8	66,7	88,9
	øB	154	154	154	154	190,5	243	243
	C	41	41	41	41	63,5	89	89
	D	38	38	38	38	57	82,5	82,5
	E	32	32	32	32	38	44,5	44,5
	F	82,5	82,5	82,5	82,5	127	178	178

FIGURE C921.9
INTERVENTION FIXTURE DOCKING/ROTARY



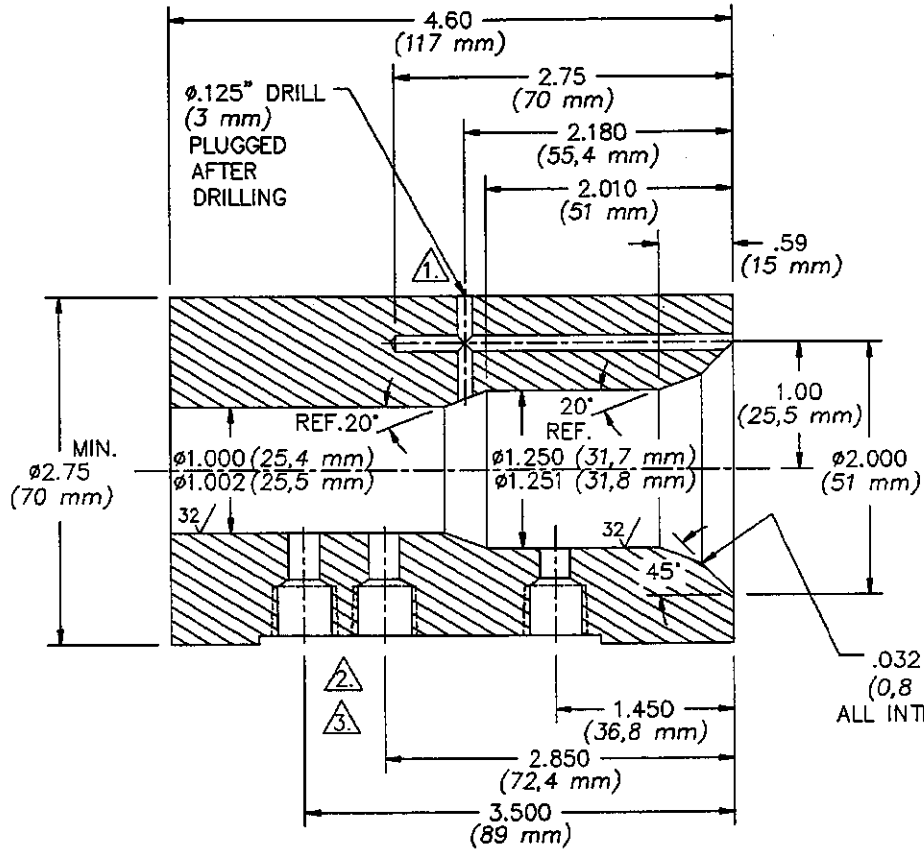
SIZE (NOM)	DIMENSIONS				
	ØA	B	C	D	E°
1-3/8"	1.375 / 1.378	.37	.50	.87	45°
(35 mm)	(34,9) / (35,0)	(9,5)	(12,5)	(22)	(45°)

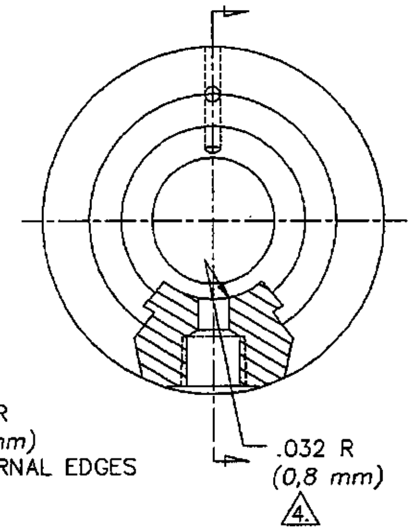
NOTES:

1. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED. TOLERANCES ARE AS FOLLOWS:
   3 PLACE DECIMAL – ±.01 (± 0,2 mm)
   2 PLACE DECIMAL – ±.03 (± 0,5 mm)
   FRACTION – ±1/16 (± 1 mm)
2. COUPLING MUST HAVE OPENING AT BACK TO ALLOW FOR VENTING.
3. ALL SEAL BORE DATUMS SHALL BE TOLERANCED FROM THE FACE OF THE COUPLING TO ±.01 (0,3 mm)
4. MULTIPLE PORT COUPLING MADE BY REPEATING C AND D DIMENSIONS
5. PORTING INTO BORE MUST NOT COME WITHIN 1/16" (2 mm) OF THE STRAIGHT BORE OF THE "C" DIMENSION. DEBUR ALL SHARP EDGES.

FIGURE C921.10
INTERVENTION FIXTURE
FLUID COUPLING (PRESSURE BALANCED)

FIGURE C921.11
INTERVENTION FIXTURE
FLUID COUPLING (PRESSURE BALANCED)





1. VENT PORT TO PREVENT HYDRAULIC LOCK PORT CAN BE DRILLED AS SHOWN OR CAN BE INCLUDED IN THE MALE STAB.

2. PORT CONNECTIONS CAN BE POSITIONED AROUND CIRCUMFERENCE TO DESIRED POSITION.

3. IF REQUIRED AN ADDITIONAL PORT CAN BE ADDED AT +0.650" (16,5 mm) PAST THE LAST PORT SHOWN THE MAX. TOLERANCE FROM THE FACE IS ±0.01" (±0,2 mm)

4. FLUID PORTS TO BE DE-BURRED TO PREVENT SEAL DAMAGE DURING INSERTION.

5. NUMBER OF FLUID PORTS, THREAD SIZES AND MOUNTING DETAILS TO SUIT APPLICATION

6. ALL DIMENSIONS ARE IN INCHES (mm) UNLESS OTHERWISE SPECIFIED.
TOLERANCES ARE AS FOLLOWS:
3 PLC DECIMAL – ±0.01 (±0,2 mm)
2 PLC DECIMAL – ±0.03 (±0,5 mm)

7. MATERIAL HAS MIN. YIELD STRESS OF 36,000 PSI (250 MPa)

APPENDIX D
PROCEDURE FOR THE APPLICATION OF A COATING SYSTEM

D1 SCOPE. This specification covers the application of a standard protective paint coating system for subsea equipment.

D2 PURPOSE. The purpose of this protective coating procedure is to ensure the proper preparation of the material and proper application of the coating. There are a number of paint companies that manufacture high quality two part epoxy - polyamide paints suitable to coat subsea equipment. This procedure describes how to apply this type of paint to the subsea equipment.

D3 SURFACE PREPARATION.

D3.1 All surfaces to be coated shall be grit blasted to a near white metal finish in accordance with SSPC-SP10 (Sa 2 1/2) to remove all rust, and to achieve a sharp, dense, anchor pattern profile. Open bores and other access to operable components should be thoroughly blocked in a manner to prevent shot blast grit from entering tree internals.

D3.2 Any oil and/or grease shall be removed with an appropriate solvent before priming.

D3.3 Blast cleaning shall not be carried out on wet surfaces, nor shall blast cleaning be carried out when surfaces are less than 5°F (3°C) above dew point.

D3.4 The compressed air supply used for blasting shall be supplied at a minimum pressure of 70 psi (0,5 MPa) free of water and oil.

D3.5 No acid washes or other cleaning solutions shall be used on metal surfaces after they have been blasted. This includes inhibited washes intended to prevent rusting.

D3.6 Surface laminations shall be ground out, and weld splatter shall be removed. Other surface irregularities including rough capping, undercut and slag together with sharp or rough edges, fins and burrs, shall be power wire brushed, ground or chipped as necessary to render the substrate suitable for coating.

D3.7 Areas that will not be painted and that require protection shall be adequately masked.

D3.8 If any rust forms after initial blasting, the rusted surfaces shall be reblasted and cleaned prior to priming.

D4 PRIMING.

D4.1 All sand and dust shall be blown from the surfaces to be primed with dry, oil-free compressed air or nitrogen gas.

D4.2 The primer shall be applied with spray, preferably airless spray equipment.

D4.3 Blast cleaned surfaces shall be coated with the specified primer within four (4) hours after grit blasting.

D4.4 The primer shall be applied within the relative humidity specified by the paint manufacturer.

D5 COATING SYSTEMS.

D5.1	Coat	Type	Dry Film Thickness Thousands of Inch (mm) (Min./Max.)
	Primer	Red Lead Oxide Epoxy Prime	2.5/3.0 (0,065/0,075)
	Second	High Solid Epoxy	5/6 (0,13/0,15)
	Third	High Solid Epoxy	5/6 (0,13/0,15)

D5.2 Drying times between coats shall be strictly in accordance with the paint manufacturer's instructions.

D5.3 All coatings shall be mixed, thinned and applied in accordance with the manufacturer's instructions.

D6 TOUCH UP OF COATING SYSTEM. All touch up coatings shall be the same manufacturer's materials as the original coatings. Where sandblasting is impractical, power wire brush to remove all oxidation will be acceptable. Six inches (150 mm) around the damaged area may also be wire brushed or lightly sanded by hand to roughen the epoxy to promote adhesion.

D6.1 Repair of Coating Damage Down to Metal. Clean area with solvent to remove all oil and grease, wire brush if shiny. If the manufacturer supplies a solvent that will assist in repair, apply the solvent to the coated areas adjacent to the damaged area. When the adjacent coating becomes tacky, apply the coating system described in Section 5.

D6.2 Repair of Epoxy Coating Damage Not Extending to Metal. Sandpaper and feather out area to be repaired. Clean off with dry oil-free compressed air or nitrogen gas. Apply the high solid epoxy coatings as necessary to achieve the original finish.

D7 INSPECTION.

D7.1 A calibrated paint film thickness device shall be used to measure the dry film thickness at each stage of the painting process.

D7.2 When dry film thicknesses are less than those specified, additional coatings shall be applied as necessary to achieve specified thickness.

D7.3 All coatings shall be free of pin holes, voids, bubbles, and other holidays.

APPENDIX E
CALCULATION OF PRESSURE RATINGS FOR API MUDLINE EQUIPMENT

E1 INTRODUCTION. The purpose of this appendix is to define the methods to be used for calculating the rated working pressure and test pressure for API mudline equipment only, which are consistent with accepted engineering practice. Mudline equipment design is a unique combination of tubular goods and hanger equipment, and therefore these methods and allowable stresses are not intended to be applied to any other type of equipment. Fatigue analysis, thermal expansion considerations and allowable values for localized bearing stress are beyond the scope of these rated working pressure calculations.

NOTE: *As an alternative to the method presented in this appendix, the designer may use the rules of the ASME Code, Section VIII Division 2, Appendix 4, modified in accordance with API Specification 6A, Section 303.3a. In this case bending stresses in wall section discontinuities can be treated as secondary stresses. However, when using this alternative method, the calculation for rated working pressure must be made in combination with loads applied by the rated running capacity (if applicable) and the rated hanging capacity as well as thermal loads. The designer shall ensure that strains resulting from these higher allowable stresses do not impair the function of the component, particularly in seal areas.*

E2 DETERMINATION OF APPLIED LOADS. For each component to be rated, the most highly stressed region in the component when subjected to the worse case combination of internal pressure and pressure end load shall be established. In performing this assessment, bending and axial loads other than those induced by the pressure end caps and threaded end connections required for imposition of pressure end load may be ignored. Specifically, axial or bending loads caused by the connection of the component to other pieces of equipment in service need not be considered.

In establishing the most highly stressed region of the component, considerable care must be used to insure that loads applied through any casing threads which are machined into the component are included. The presence of threads cut into the wall of a component and the pressure end loads imparted to the main body of the component through these threads results in local bending stress which must be considered. The general shape of the main body of the component may also result in section bending stress, especially when pressure end load is added. These shape effects shall also be considered when determining the loads on the component.

E3 DETERMINATION OF STRESSES. After the location of the highest stress for any given component and loading condition has been determined, the stress distribution across the critical section shall be linearized to establish the membrane stress, S_m, local bending stress, S_b, and peak stress, F, in the section, Figure E1 (ref: API RP-2R, 1984, Section 3.5). The linearization operation shall be performed on each component of stress. The individual linearized components shall then be used to calculate a von Mises equivalent stress through the cross section. The von Mises equivalent stress or Distortion Energy stress, S_e, shall be calculated as follows:

$$S_e = [S_x^2 + S_y^2 + S_z^2 - S_xS_y - S_xS_z - S_yS_z + 3\,(S_{xy}^2 + S_{xz}^2 + S_{yz}^2)]^{1/2}$$

Where S_x, S_y, S_z are the component normal stresses at a point and S_{xy}, S_{xz}, S_{yz} are the component shear stresses at a point. The subscripts x, y and z refer to the global coordinate system.

The linearization operation can be done by hand calculation but is more often done using a computer program. If a computer program or FEA post processing program is used, caution must be used to verify that the program is calculating the linearization stresses correctly. A check on computer output is highly recommended. One such simple check for FEA post processing programs is to construct an FEA model of a simple beam in four point bending. This model should be analyzed for plane strain conditions and should have a beam depth made up of at least five elements. The linearized von Mises stress through the center section of such a beam should produce no von Mises membrane stress.

The von Mises stress values of interest in the cross section of the component being studied are the linearized membrane (net section) stress, and the linearized local bending stress as shown in Figure E1. These values consider the multiaxial stress condition at a point since they are von Mises equivalent stresses.

E4 ALLOWABLE STRESS LEVELS FOR WORKING AND TEST CONDITIONS. The allowable stress levels for test and working conditions are based on percentages of membrane plus bending and membrane only stress required to yield the material. For the case of the stresses used in this document, the local membrane and bending stress calculated in Section E3 shall be considered primary stresses since they are the stresses required to provide static equilibrium of the section with the applied pressure and end loads.

In order to understand what allowable levels should be used for this case, the limiting situation of full section yielding must be defined. Assuming the simple case of a rectangular beam and an elastic-perfectly plastic material, a plot of limiting membrane plus bending versus membrane only stress can be made (Reference: ASME: Criteria of the ASME Boiler and Pressure Vessel Code for Design by Analysis in Sections III and VIII, Division 2). Figure E2 shows the limiting values of various combinations of membrane plus bending and membrane only stress normalized using the minimum specified material yield strength, S_{yld}. The limit stress ratio for membrane only is 1.0 and for bending only the limit is 1.5. If a membrane stress less than 2/3 S_{yld} is added to a large bending stress, the membrane plus bending stress ratio may exceed 1.5. This is due to the stiffening effect of the membrane stress and shifting of the beam's neutral axis. This increase in bending capacity when axial load is applied is generally ignored.

E5 TEST PRESSURE. For the purposes of this standard, the allowable von Mises stress for hydrostatic test conditions on both suspension and conversion equipment are as follows:

Membrane Stress:

$S_M \leq 0.90\ S_{yld}$

Membrane plus Bending Stress:

$S_M + S_B \leq 1.35\ S_{yld}$ *for* $S_M \leq 0.67\ S_{yld}$

$S_M + S_B \leq 2.15\ S_{yld} - 1.2\ S_M$ *for* $0.67\ S_{yld} \leq S_M \leq 0.90\ S_{yld}$

The allowable test pressure shall be that needed to cause any of the stress allowables to occur in the critical cross section of the component when pressure and end loads due to test end caps or plugs are considered. It is noted that the above limits, shown in Figure E1 for clarity, are identical to those given in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, Part AD for hydrostatic test conditions.

E6 RATED WORKING PRESSURE.

E6.1 MUDLINE SUSPENSION EQUIPMENT. For the purposes of this standard, the allowable von Mises stress for working conditions for mudline suspension equipment are as follows:

Membrane Stress:

$S_M \leq 0.80\ S_{yld}$

Membrane plus Bending Stress:

$S_M + S_B \leq 1.2\ S_{yld}$ *for* $S_M \leq 0.67\ S_{yld}$

$S_M + S_B \leq 2.004\ S_{yld} - 1.2\ S_M$ *for* $0.67\ S_{yld} \leq S_M \leq 0.8\ S_{yld}$

The rated working pressure shall be that needed to cause these stresses to occur in the critical cross section of the component being considered. These limits are about 90% of test conditions.

E6.2 MUDLINE CONVERSION EQUIPMENT. For the purposes of this standard, the allowable von Mises stress for working conditions for mudline conversion equipment are as follows:

Membrane Stress:

$S_M \leq 0.67\ S_{yld}$

Membrane plus Bending Stress:

$S_M + S_B \leq S_{yld}$

The rated working pressure shall be that needed to cause these stresses to occur in the critical cross section of the component being considered. These limits are about 75% of test conditions. The conditions coincide with the normal design stress limit of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 2. It is to be noted that the membrane stress limit for conversion equipment operating condition is more conservative than that for suspension equipment. This is to account for the fact that the suspension equipment is used in service as a part of the casing string. API rated casing string components typically have higher allowable stress limits than API rated completion or production equipment.

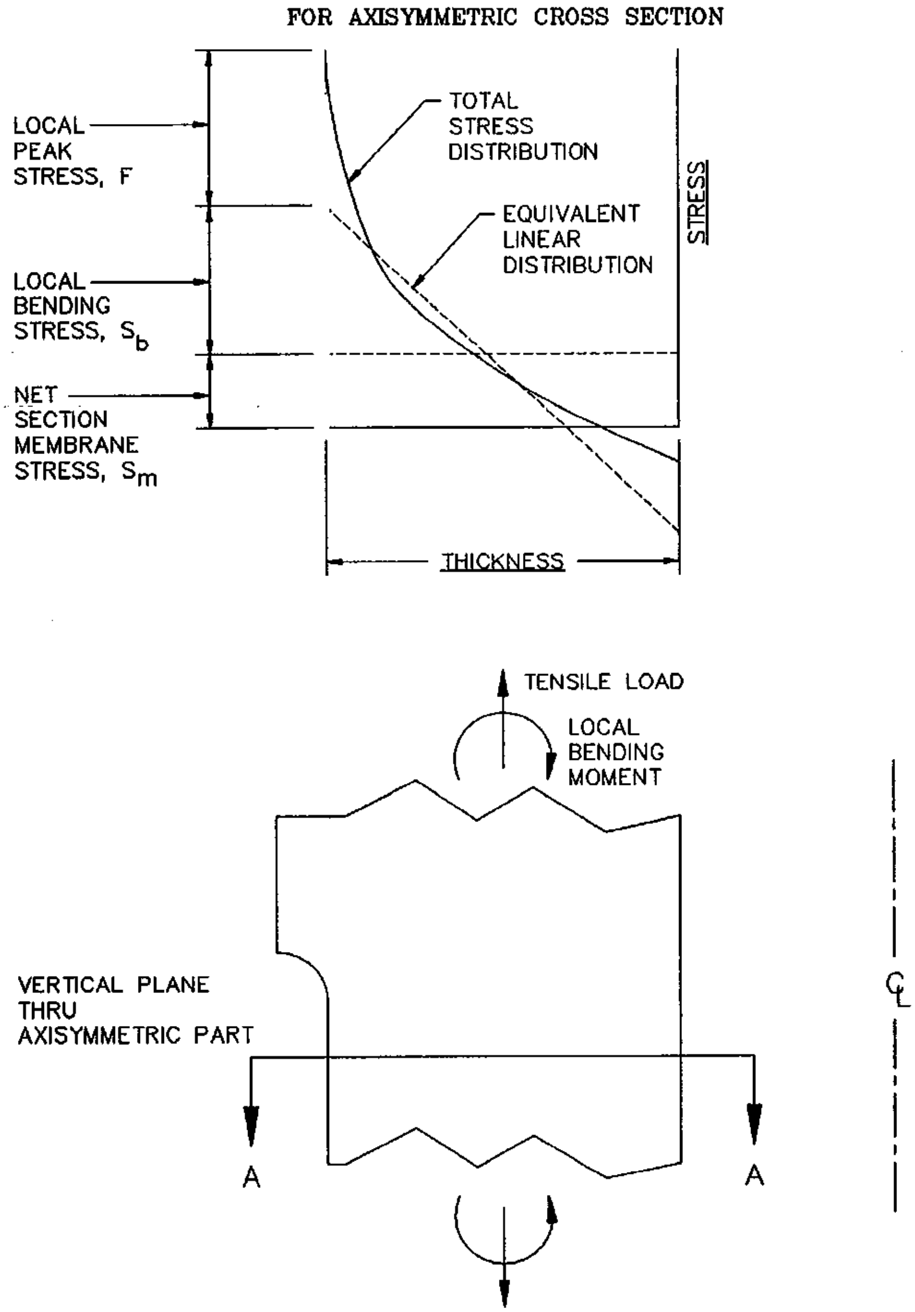


FIGURE E1
STRESS DISTRIBUTION ACROSS SECTION A-A

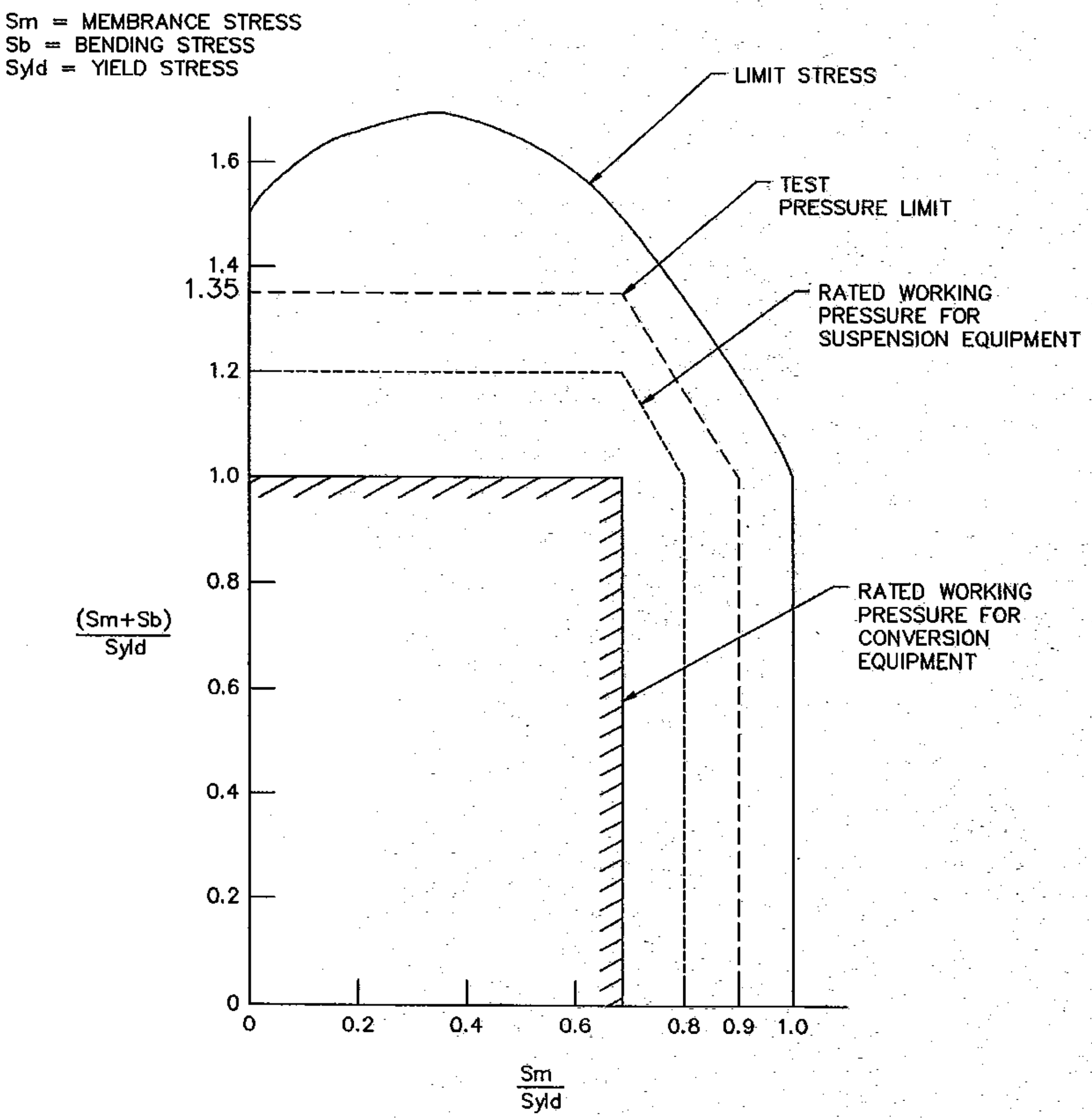


FIGURE E2
LIMIT STRESS FOR COMBINED MEMBRANE AND BENDING
(RECTANGULAR SECTION)

APPENDIX F
RECOMMENDED FLANGE BOLT TORQUE

BOLT SIZE	40,000 PSI Stress (276 MPa) BOLT TENSION lbf	(Newtons)	MAKE UP TORQUE ft-lbs	(N-m)	52,500 PSI Stress (362 MPa) BOLT TENSION lbf	(Newtons)	MAKE UP TORQUE ft-lbs	(N-m)	70,000 PSI Stress (483 MPa) BOLT TENSION lbf	(Newtons)	MAKE UP TORQUE ft-lbs	(N-m)
1/2 – 13 UNC	5674	(25238)	45	(61)	7448	(33129)	59	(80)	9930	(44169)	79	(107)
5/8 – 11 UNC	9026	(40148)	86	(117)	11846	(52691)	113	(153)	15796	(70261)	151	(205)
3/4 – 10 UNC	13355	(59403)	150	(203)	17528	(77965)	196	(266)	23371	(103954)	263	(357)
7/8 – 9 UNC	18482	(82208)	239	(324)	24257	(107895)	313	(424)	32344	(143866)	418	(567)
1 – 8 UN	24229	(107771)	361	(489)	31800	(141446)	474	(643)	42401	(188600)	632	(857)
1 1/8 – 8 UN	31617	(140632)	522	(708)	41497	(184579)	686	(930)	55330	(246108)	914	(1239)
1 1/4 – 8 UN	39987	(177862)	726	(984)	52483	(233444)	953	(1292)	69977	(311258)	1271	(1723)
1 3/8 – 8 UN	49339	(219460)	976	(1323)	64757	(288039)	1281	(1737)	86343	(384054)	1708	(2316)
1 1/2 – 8 UN	59672	(265421)	1277	(1731)	78320	(348367)	1676	(2272)	104426	(464487)	2235	(3030)
1 5/8 – 8 UN	70988	(315755)	1635	(2217)	93171	(414425)	2146	(2910)	124229	(552871)	2861	(3879)
1 3/4 – 8 UN	83254	(370447)	2054	(2785)	109311	(486215)	2695	(3654)	145695	(648051)	3595	(4874)
1 7/8 – 8 UN	96563	(429512)	2538	(3441)	126739	(563735)	3331	(4516)	168985	(751645)	4442	(6022)
2 – 8 UN	110624	(492945)	3093	(4193)	145456	(646988)	4060	(5505)	193942	(862654)	5413	(7339)
2 1/4 – 8 UN	142290	(632906)	4435	(6013)	186755	(830686)	5821	(7892)	249008	(1107588)	7761	(10522)
2 1/2 – 8 UN	177683	(790334)	6116	(8292)	233209	(1037314)	8028	(10884)	310945	(1383083)	10703	(14511)
2 5/8 – 8 UN	196852	(875598)	7097	(9622)	258368	(1149221)	9314	(12628)	344491	(1532296)	12420	(16839)
2 3/4 – 8 UN	217003	(965229)	8176	(11085)	284817	(1266866)	10731	(14549)	379755	(1689150)	14308	(19399)

Note: It is recognized that applied torque to a nut member is only one of several ways to approximate tension and unit stress in a stud bolt. Tabulated values are presented for convenience and guidance only.

Some factors which affect the relationship between nut torque and bolt stress are:

Thread pitch, pitch diameter, and thread form.
Surface finish of thread faces and nut bearing surface area.
Degree of parallelism of nut bearing area with flange face.
Type of lubrication of the threads and nut bearing surface area.

The following formulae were used in establishing the values in the Table:
Hexagon Size (Heavy Hex Nuts), inches = D (1.5) + .125
Hexagon Size (Heavy Hex Nuts), mm = D (1.5) + 3.175

$$A_s = \left(\frac{\pi}{4}\right)\left(D - \frac{0.9743}{N}\right)^2$$

$$F = A_s\,(\text{Bolt Stress}) \text{ — lbf}$$

$$T = \frac{F\,(PD)\left[\frac{1}{N} + \pi\,(f)\,(PD)\,(\text{Secant } 30°)\right]}{2\,(12)\left[\pi\,(PD) - (f)\left(\frac{1}{N}\right)(\text{Secant } 30°)\right]} + \frac{\text{Hex Size} + D + .125}{(4)\,(12)}\,(F)\,(f) \text{ — ft-lbs}$$

D = Nominal Bolt Diameter — in
A_s = Effective Stress Area
F = Force or Bolt Tension Pound-Force (lbf)
T = Torque — ft-lbs
N = Threads per inch
PD = Pitch Diameter of Thread — in
f = Friction Factor (.13 with threads and nut bearing area well lubricated with API Bul 5A2 Thread Compound)

Metric Flange Bolt Torque Formulae

D = Bolt Diameter — mm
A_s = Effective Stress Area — mm²
F = Bolt Tension — N
T = Torque — N·m
N = Threads per millimeter
PD = Pitch Diameter — mm
f = Friction Factor — Dimensionless

$$A_s = \left(\frac{\pi}{4}\right)\left(D - \frac{0.9743}{N}\right)^2 \text{ — mm}^2$$

$$F = A_s \times (\text{Bolt Stress}) \text{ — N}$$

$$T = \frac{F\,(PD)\left[\frac{1}{N} + \pi\,(f)\,(PD)\,(\text{Secant } 30°)\right]}{(2)\,(10^2)\left[\pi\,(PD) - (f)\left(\frac{1}{N}\right)(\text{Secant } 30°)\right]} + \frac{\text{Hex Size} + D + 3.175}{(4)\,(10^2)}\,(F)\,(f) \text{ — N·m}$$

Note: Metric equivalents for bolt tension and make up torque are listed for convenience, even though inch-size bolts are recommended for use with this specification.

APPENDIX G
RECOMMENDED GUIDELINES FOR DESIGN AND TESTING OF SUBSEA WELLHEAD RUNNING, RETRIEVING AND TESTING TOOLS

G1 GENERAL. This appendix covers recommended guidelines for design and testing of tools for running, retrieving and testing all subsea wellhead components including guidance equipment, housings, casing suspension equipment, annulus sealing equipment and protective devices.

G2 DESIGN.

G2.1 Loads. As a minimum, the following loads should be considered when designing the running, retrieving and testing tools:

- Suspended Weight
- Bending Loads
- Pressure
- Torsional Loads
- Radial Loads
- Overpull
- Environmental Loads

G2.2 End Connections. Tool joints or casing threads should be in conformance with API Specification 7. Casing threads should be in conformance with either API Specification 6A, Section 902 or 918. The tool should have an adequate dimension for tonging. The load capacity of the tool should not be inferred from the choice of end connections for the tool.

G2.3 Vertical Bore. Tools with through bore should have a sufficient I.D. to allow the passage of tools required for subsequent operations as per the manufacturer's written specification.

G2.4 Outside Profile. The outside profile of the tools should be per the manufacturer's written specification. The length, outside profile, and fluid bypass area should be designed to minimize surge/swab pressure and for ease of running while tripping and circulating.

G2.5 Load Capacity. Tool load ratings should be per the manufacturer's written specification.

G2.6 Vent. The conductor housing running tool should be provided with a vent or system of vents. This system of vents is used to either fill the conductor with fluid during running or to allow the passage of cuttings during a jetting operation.

G2.7 Pressure Rating. The pressure rating of the tool should be per the manufacturer's written specification.

G3 MATERIALS.

G3.1 The materials used in these tools should be chosen for strength and need not be resistant to corrosive environments and should comply to the manufacturer's written specification.

NOTE: *If exposure to severe stress cracking environments is expected, special practices beyond the scope of this document may be required.*

G3.2 Coatings should conform to Section 304.7 of this specification.

G4 TESTING.

G4.1 Performance Verification Testing. Should conform to Section 307 of this specification.

G4.2 Factory Acceptance Testing. All tools should be functionally tested, dimensionally inspected or gaged to verify their correct operation prior to shipment from the manufacturer's facility. Tools with hydraulic operating systems should have the hydraulic system tested per the manufacturer's written specification. This hydrostatic test should consist of three parts.

- The Primary Pressure-Holding Period
- The Reduction of the Pressure to Zero (Atmospheric)
- The Secondary Pressure-Holding Period

Each holding period should not be less than 3 minutes; the timing of which should not start until the external surfaces of the body members have been thoroughly dried, the test pressure has been reached, and the equipment and the pressure monitoring gage have been isolated from the pressure source.

APPENDIX H
EQUIPMENT MARKING — API LICENSEES

H1 GENERAL. Equipment marked "17D" shall meet the requirements of this specification.

Equipment shall be marked in accordance with Section 700 of API Specification 6A, except that the marking "17D" shall replace the marking "6A". For equipment which meets all the requirements of both API Specifications 6A and 17D, both markings "6A" and "17D" may be applied. Similarly for equipment which meets all the requirements of both API Specifications 14D and 17D, both the markings "14D" and "17D" may be applied. All equipment marked "17D" shall also be marked with the following minimum information: part number, manufacturer name or trademark. The API monograms may be applied to API Specification 17D equipment by API Specification 17D Licensees only. Refer to Table 701.1 in API Specification 6A for metallic marking locations. In addition, API 17D Specification subsea tree assemblies which meet all of the requirements in Section 922 of this specification may also be monogrammed (by API Specification 17D Licensees only) as "17D" tree assemblies, with the monogram applied on the tree assembly nameplate.

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