API Specification

6A

19th Edition, July 2004
Specification for Wellhead and Christmas Tree Equipment

National Adoption of ISO 10423—Petroleum and natural gas industries—Drilling and production equipment—Wellhead and Christmas tree equipment

Annex A (informative)

Purchasing Guidelines

API Monogram® Required ☐ Yes ☐ No

Annex A
(informative)

Purchasing guidelines

A.1 General

This annex provides guidelines for enquiry and purchase of wellhead and christmas tree equipment. These guidelines consist of data sheets to be completed by the purchaser, a series of typical wellhead and christmas tree configurations, and a decision tree for determining product specification levels.

The data sheets are designed to perform two functions:

a) assist the purchaser in deciding what he wants;

b) assist the purchaser in communicating his particular needs and requirements, as well as information on the well environment, to the manufacturer for his use in designing and producing equipment.

To use this Annex A, a copy of the data sheets should be completed as accurately as possible. The typical configurations should be referred to, as needed, to select the required equipment. The decision tree Figure A.3, together with its instructions, provides the recommended practice as to which PSL each piece of equipment should be manufactured. A copy of the data sheet should then be attached to the purchase order or request for proposal.

A.2 Data sheets

The following pages contain questions and information that can be used to select wellhead equipment, including chokes and actuators. Table A.2 contains general information which pertains to the entire well. Tables A.3 to A.12 are designed to be used for each type of equipment.

The effects of external loads (i.e. bending moments, tensions, etc.) on the assembly of components are not explicitly addressed by this International Standard (see 4.2.1.3). The purchaser should specify any exceptional loading configuration.

The purchaser should specify whether the performance verification procedures in Annex F are applicable.

A.3 Typical wellhead and christmas tree configurations

Examples of typical wellhead and christmas tree configurations are shown in Figure A.1 and Figure A.2. Also included are examples of casing and bit programmes that are consistent with the wellheads as shown.

A.4 Product specification levels (PSL)

A.4.1 General

PSL 1 includes practices currently being implemented by a broad spectrum of the industry for service conditions recommended in this Annex A.

PSL 2 includes all the requirements of PSL 1 plus additional practices currently being implemented by a broad spectrum of the industry for a specific range of service conditions as described in this Annex A.

PSL 3 includes all the requirements of PSL 2 plus additional practices currently being implemented by a broad spectrum of the industry for a specific range of service conditions as described in this Annex A.

PSL 3G includes all the requirements of PSL 3 plus additional practices currently being implemented by a broad spectrum of the industry for a specific range of service conditions as described in this Annex A. The designation PSL3G is only utilized in those clauses and tables where necessary to define the additional gas-testing requirements of equipment that can be gas-tested.

PSL 4 includes all the requirements of PSL 3G plus certain additional requirements and is intended for applications that exceed the service conditions usually identified within the scope of this International Standard, and is normally only used for primary equipment.

Figure A.3 shows the recommended specification level for primary equipment. Primary equipment of a wellhead assembly includes as a minimum:

— tubing head;

— tubing hanger;

— tubing head adapter;

— lower master valve.

All other wellhead parts are classified as secondary. The specification level for secondary equipment may be the same as or less than the level for primary equipment.

The selection of PSL should be based on a quantitative risk analysis which is a formal and systematic approach to identifying potentially hazardous events, and estimating the likelihood and consequences to people, environment and resources, of accidents developing from these events.

The following comments apply to the basic questions asked in Figure A.3.

A.4.2 NACE MR 0175

This applies if the partial pressure of hydrogen sulfide (H_2S) in the produced fluid equals or exceeds the minimum amount specified by NACE MR 0175 for sour service.

A.4.3 High H_2S concentration

Use “Yes” if the H_2S concentration of the produced fluid is such that in air an H_2S concentration of 70×10^{-6} (70 ppm) can develop in case of a leak (human sense of smell cannot detect concentrations higher than 70×10^{-6}).

Alternatively use "Yes" if the radius of exposure (ROE) to 100 ppm H_2S is greater than 15 m (50 ft) from the wellhead. ROE is defined in Texas Railroad Commission Rule 36, see A.4.4. Other methods of calculating ROE may apply depending on local regulations.

The above requires the knowledge of the adjusted open-flowrate of offset wells. If this is not available, but if hydrogen sulfide can be expected, a 100 ppm ROE equal to 1000 m (3000 ft) may be assumed.

A.4.4 Close proximity

Users who are accustomed to the use of the close-proximity and radius-of-exposure concepts may substitute close proximity for gas well in Figure A.3.

The proximity assessment should consider the potential impact of an uncontrolled emission of H_2S threatening life and environment near the wellhead. The following list of items can be used for determining potential risk:

a) 100 ppm ROE of H_2S is greater than 15 m (50 ft) from the wellhead and includes any part of a public area except a public road. ROE is defined in A.4.5. Public area means a dwelling, place of business, place of worship, school, hospital, school bus stop, government building, a public road, all or any portion of a park, city, town, village, or other similar area that one can expect to be populated. Public road means any street or road owned or maintained for public access or use;

b) 500 ppm ROE of H_2S is greater than 15 m (50 ft) from the wellhead and includes any part of a public area including a public road;

c) well is located in any environmentally sensitive area such as a park, wildlife preserve, city limits, etc.;

d) well is located within 46 m (150 ft) of an open flame or fired equipment;

e) well is located within 15 m (50 ft) of a public road;

f) well is located in or near inland navigable waters;

g) well is located in or near surface domestic water supplies;

h) well is located within 107 m (350 ft) of any dwelling.

These conditions are recommended minimum considerations. Any local regulatory requirements should be met.

A.4.5 Radius of exposure (ROE) of H_2S

A.4.5.1 The following information is taken from Texas Railroad Commission Rule 36. SI metric-equivalent rules are not given, as the method of ROE determination is used in the United States only. Other methods of calculating ROE may apply depending on local regulations.

A.4.5.2 For determining the location of the 100 ppm ROE:

$$X = [(1{,}589)(\text{mole fraction } H_2S)(q)]^{0{,}6258}$$

For determining the location of the 500 ppm ROE:

$$X = [(0{,}454\ 6)(\text{mole fraction } H_2S)(q)]^{0{,}6258}$$

where

X is the radius of exposure, in feet;

q is the maximum volume flowrate determined to be available for escape, in cubic feet per day;

H_2S is the mole fraction of hydrogen sulfide in the gaseous mixture available for escape.

A.4.5.3 The volume flowrate used as the escape rate in determining the radius of exposure shall be that specified below, as applicable.

a) For new wells in developed areas, the escape rate shall be determined by using the current adjusted open-flowrate of offset wells, or the field-average current adjusted open flowrate, whichever is larger.

b) The escape rate used in determining the radius of exposure shall be corrected to standard conditions of 14,65 psia and 60 °F (16 °C).

A.5 Corrosivity of retained fluid

To select the desired material class in Table 3, the purchaser should determine the corrosivity of the retained, produced or injected fluid by considering the various environmental factors and production variables listed in Table A.2. General corrosion, stress-corrosion cracking (SCC), erosion-corrosion, and sulfide stress cracking (SSC) are all influenced by the interaction of the environmental factors and the production variables. Other factors and variables not listed in Table A.2 may also influence fluid corrosivity.

The purchaser shall determine if materials shall meet NACE MR 0175 for sour service. NACE MR 0175 is only concerned with the metallic material requirements to prevent sulfide stress cracking and not with resistance to general corrosion. Consideration should also be given to the carbon dioxide partial pressure, which generally relates to corrosivity in wells as shown in Table A.1. This table is a guideline only.

Analysis of produced fluids may not predict the field performance of metallic or non-metallic material.
The minimum partial pressure of carbon dioxide required to initiate corrosion and the relative effect of increasing partial pressures on the corrosion rate are strongly influenced by other environmental factors and production variables, such as:

a) temperature;

b) H_2S level;

c) pH;

d) chloride ion concentration;

e) sand production;

f) water production and composition;

g) types and relative amounts of produced hydrocarbons.

Finally, the purchaser should consider future service of the well when selecting a material class. This should not be limited to anticipated changes in the acid gas partial pressures for production or increased water production with or without increased chloride content, but also should include consideration of operations such as acidification or other well treatments.

A.6 Chokes

Orders for chokes shall specify the size and pressure rating of the inlet connection as well as size, type and pressure rating of the outlet connection, first listing the inlet connection and then the outlet connection, the working pressure, and type (i.e. adjustable or positive). Orders for adjustable chokes should specify the maximum orifice diameter. Orders for positive chokes should specify the type of flow bean together with its maximum orifice size.

Table A.1 — Relative corrosivity of retained fluids as indicated by CO_2 partial pressure

Retained fluids	Relative corrosivity	Partial pressure of CO_2	
		MPa	(psia)
General service	non-corrosive	< 0,05	(< 7)
General service	slightly corrosive	0,05 to 0,21	(7 to 30)
General service	moderately to highly corrosive	> 0,21	(> 30)
Sour service	non-corrosive	< 0,05	(< 7)
Sour service	slightly corrosive	0,05 to 0,21	(7 to 30)
Sour service	moderately to highly corrosive	> 0,21	(> 30)

Table A.2 — Wellhead equipment data sheet — General

Well name(s) and location(s): _____

Maximum operating pressure: _____

Anticipated wellhead shut-in pressure: _____

Temperature ranges anticipated: _____

Minimum ambient temperature: _____

Maximum flowing fluid temperature at wellhead: _____

Anticipated composition of produced fluids: CO_2 _____ (mg) _____ Chlorides _____ (mg)

_____ H_2S _____ (mg) _____ Other _____

Anticipated completion or future workover or recovery operations which would affect pressure, temperature or fluid content:

_____

New values: _____

Are there any government regulations that apply or must be met by this equipment? _____

If so, which one(s)? _____

Water or brine pH: _____

Does NACE MR 0175 apply? _____

Will scale, paraffin, corrosion or other types of inhibitors be used? _____

Inhibitor type: _____ Inhibitor carrier: _____ Batch or continuous inhibition? _____

Will acidification be performed? _____ Type of acid: _____

Anticipated production rates: _____ m^3/d oil/condensate

_____ m^3/d gas

_____ m^3/d S&W [a]

Will erosion be a concern? _____ Cause: _____

External coating? Yes, type _____ No _____

Internal coating? Yes, type _____ No _____

Delivery requirements: _____

Special shipping, packing and storage instructions: _____

Table A.2 — Wellhead equipment data sheet — General, continued

Casing programme

	Top joint in string					
	Size (OD)	**kg/m** (lb/ft)	**Grade**	**Connection**	**Total string hanging wt** daN (lbs)	**Bit size** mm (in)
Conductor						
Surface casing						
Protective casing						
Production casing						
Tubing						
Type of completion: single or multiple						

[a] Sand and water.

Table A.3 — Wellhead equipment data sheet — Casing-head housing

Casing-head housing	PSL: _____ PR: _____
Bottom connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Top connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Outlets:	Size: _____
	Rated working pressure: _____
	Type: _____
	Number: _____
Equipment for outlets:	Valve-removal plug: _____
	Valves (inboard): Qty _____ PSL: _____ PR: _____
	Valves (other): Qty_____ PSL: _____ PR: _____
	Companion flanges: Qty ____ PSL: _____
	Bullplugs: Qty _____
	Nipples: Qty _____
	Needle valves: Qty _____
	Gauges: Qty _____
Lock screws? Yes _____ No _____	Lock screw function: _____
Baseplate requirements: _____	
Special material requirements: _____	
Casing hanger:	
Size: _____	
Type: _____	
PSL: _____	
PR: _____	
Temperature rating (Table 2): _____	
Material class (Table 3): _____	
Retained fluid corrosivity (Table A.1): _____	
Witness? Yes [a] _____	No _____
External coating? No _____ Yes _____	If yes, type _____
Internal coating? No _____ Yes _____	If yes, type _____
Flange bolting requirements (Table 49)	Non-exposed ___ Exposed ____ Exposed (low strength) ___
Main run (studs): _____	(nuts): _____
Outlet inboard (studs): _____	(nuts): _____
Outlet other (studs): _____	(nuts): _____
Test and auxiliary equipment:	
Wear bushing: _____	
Running and retrieving tools: _____	
Test plug: _____	
Other requirements: _____	

[a] If yes, specify what and by whom.

Table A.4 — Wellhead equipment data sheet — Casing-head spool

Casing-head spool	PSL: _____ PR: _____
Bottom connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Top connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Outlets:	Size: _____
	Rated working pressure: _____
	Type: _____
	Number: _____
Equipment for outlets:	Valve-removal plug: _____
	Valves (inboard): Qty _____ PSL: _____ PR: _____
	Valves (other): Qty _____ PSL: _____ PR: _____
	Companion flanges: Qty ____ PSL: _____
	Bullplugs: Qty _____
	Nipples: Qty _____
	Needle valves: Qty _____
	Gauges: Qty _____
Lock screws? Yes _____ No _____	Lock screw function: _____
Special material requirements: _____	
Bottom casing spool pack-off size: _____	
Type: _____	
PR: _____	
Casing hanger:	
Size: _____	
Type: _____	
PSL: _____	
PR: _____	
Temperature rating (Table 2): _____	
Material class (Table 3): _____	
Retained fluid corrosivity (Table A.1): _____	
Witness? Yes [a] _____	No _____
External coating? No _____ Yes _____	If yes, type _____
Internal coating? No _____ Yes _____	If yes, type _____
Flange bolting requirements (Table 49)	Exposed _____ Non-exposed _____
Outlet inboard (studs): _____	(nuts): _____
Outlet other (studs): _____	(nuts): _____
Test and auxiliary equipment:	
Wear bushing: _____	
Running and retrieving tools: _____	
Test plug: _____	
Other requirements: _____	

[a] If yes, specify what and by whom.

Table A.5 — Wellhead equipment data sheet — Tubing-head spool

Tubing-head spool		PSL: _____ PR: _____
Bottom connection:		Size: _____
		Rated working pressure: _____
		Type: _____
Top connection:		Size: _____
		Rated working pressure: _____
		Type: _____
Outlets:		Size: _____
		Rated working pressure: _____
		Type: _____
		Number: _____
Equipment for outlets:		Valve-removal plug: _____
		Valves (inboard): Qty _____ PSL: _____ PR: _____
		Valves (other): Qty_____ PSL: _____ PR: _____
		Companion flanges: Qty ____ PSL: _____
		Bullplugs: Qty _____
		Nipples: Qty _____
		Needle valves: Qty _____
		Gauges: Qty _____
Lock screws? Yes _____	No _____	Lock screw function: _____
Material requirements: _____		
Bottom tubing spool pack-off:	Size: _____	
	Type: _____	
	PR: _____	
Tubing hanger:	Size: _____	
	Type: _____	
	PSL: _____	
	PR: _____	
	Back-pressure valve type: _____	
	Surface-controlled subsurface valve control lines: _____	
Temperature rating (Table 2): _____		
Material class (Table 3): _____		
Retained fluid corrosivity (Table A.1): _____		
Witness? Yes [a] _____		No _____
External coating? No _____	Yes _____	If yes, type _____
Internal coating? No _____	Yes _____	If yes, type _____
Flange bolting requirements (Table 49)		Non-exposed _____ Exposed _____ Exposed (low strength) _____
Main run (studs): _____	(nuts): _____	
Outlet inboard (studs): _____	(nuts): _____	
Outlet other (studs): _____	(nuts): _____	
Test and auxiliary equipment:		
Wear bushing: _____		
Running and retrieving tools: _____		
Test plug: _____		
Other requirements: _____		

[a] If yes, specify what and by whom.

Table A.3 — Wellhead equipment data sheet — Cross-over flange

Cross-over flange	PSL: _____ PR: _____
Bottom connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Top connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Pack-off type: _____	
Size: _____	
Temperature rating (Table 2): _____	
Material class (Table 3): _____	
Retained fluid corrosivity (Table A.1): _____	
Witness? Yes [a] _____	No _____
External coating? No _____ Yes _____	If yes, type _____
Internal coating? No _____ Yes _____	If yes, type _____
Flange bolting requirement (Table 49)	Non-exposed _____ Exposed _____ Exposed (low strength) _____
Main run (studs): _____	(nuts): _____

[a] If yes, specify what and by whom.

Table A.7 — Wellhead equipment data sheet — Tubing head adaptor

Tubing head adaptor	PSL: _____ PR: _____
Bottom connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Top connection:	Size: _____
	Rated working pressure: _____
	Type: _____
Surface-controlled subsurface safety valve outlets:	_____
Number: _____	
Size: _____	
Electrical feed-through connection?	_____
Special material requirements:	_____
Temperature rating (Table 2):	_____
Material class (Table 3):	_____
Retained fluid corrosivity (Table A.1):	_____
Witness? Yes [a] _____	No _____
External coating? No _____ Yes _____	If yes, type _____
Internal coating? No _____ Yes _____	If yes, type _____
Flange bolting requirement (Table 49)	Non-exposed _____ Exposed _____ Exposed (low strength) _____
Main run (studs): _____ (nuts): _____	

[a] If yes, specify what and by whom.

Table A.8 — Wellhead equipment data sheet — Christmas tree and choke

Christmas tree – Single ___ Dual ___ Solid block ___ Stacked ___

	Size	Material [a]	PSL	PR	Witness? [b]	External coating? If yes, state type	Flanged bolting requirements [c] Studs Nuts	Ring gasket type
Lower master valve								
Upper master valve								
Swab (crown) valve								
Wing valve—inboard								
Wing valve(s)—other								
Tee/cross (circle one)								
Choke								
End flange								
Companion flanges								
Instrument flanges								
Tree cap/top conn.								

Rated working pressure: _____

Retained fluid corrosivity (Table A.1): _____

Temperature rating (Table 2): _____

Material class (Table 3): _____

Upper master prepared for actuator: Yes _____ No _____ If yes, specify class I or II below PR column

Wing valve—inboard prepared for actuator: Yes _____ No _____ If yes, specify class I or II below PR column

Wing valve—other prepared for actuator: Yes _____ No _____ If yes, specify class I or II below PR column

Choke: adjustable or fixed: _____

Orifice size: _____ Nominal size: _____

Pressure drop: _____

Flowline connection: Size: _____

Type: _____

Special material requirements: _____

Other requirements:

Upper master valve type actuator requirements: Pneu./piston _____ Hydr./piston _____ Electric _____

Supply pressure/power _____ Pneu./diaphragm _____ Hydr./diaphragm _____ Electric _____

Air _____ Gas _____

Wing valve type actuator requirements: Pneu./piston _____ Hydr./piston _____ Electric _____

Pneu./diaphragm _____ Hydr./diaphragm _____ Electric _____

Supply pressure: _____

Other: _____

[a] Define or specify material requirements and, if cladding or other corrosion-resistant materials are to be inlaid, state base material type/clad material type, e.g., 4130/625.

[b] If yes, specify what and by whom.

[c] Indicate required bolting for the applicable retained fluid and temperature classification specified in Table 49.

Table A.9 — Wellhead equipment data sheet — Compact casing-head housing

Compact casing-head housing		PSL: _____ PR: _____
A. Bottom connection:		Size: _____
		Rated working pressure: _____
		Type: _____
Outlets:		Size: _____
		Rated working pressure: _____
		Type: _____
		Number: _____
Equipment for outlets:		Valve-removal plug: _____
		Valves (inboard): Qty _____ PSL: _____ PR: _____
		Valves (other): Qty _____ PSL: _____ PR: _____
		Companion flanges: Qty _____ PSL: _____
		Bullplugs: Qty _____
		Nipples: Qty _____
		Needle valves: Qty _____
		Gauges: Qty _____
Lock screws? Yes _____	No _____	Lock screw function: _____
Base plate requirements:		_____
Witness? No _____	Yes [a]	_____
Special material requirements:		_____
Bottom casing spool pack-off:	Size:	_____
	Type:	_____
Casing hanger:		
	Size:	_____
	Type:	_____
	PR:	_____
	PSL:	_____
Temperature rating (Table 2):		_____
Material class (Table 3):		_____
Retained fluid corrosivity (Table A.1):		_____
External coating? No _____	Yes _____	If yes, type: _____
Internal coating? No _____	Yes _____	If yes, type: _____
Flange bolting requirements (Table 49)	Non-exposed _____	Exposed _____ Exposed (low strength) _____
Outlet inboard (studs): _____	(nuts):	_____
Outlet other (studs): _____	(nuts):	_____
Other requirements: _____		

[a] If yes, specify what and by whom.

Table A.9 *(continued)*

B. Top connection:		Size: _____
		Rated working pressure: _____
		Type: _____
Outlets:		Size: _____
		Rated working pressure: _____
		Type: _____
		Number: _____
Equipment for outlets:		Valve-removal plug: _____
		Valves (inboard): Qty _____ PSL: _____ PR: _____
		Valves (other): Qty _____ PSL: _____ PR: _____
		Companion flanges: Qty _____ PSL: _____
		Bullplugs: Qty _____
		Nipples: Qty _____
		Needle valves: Qty _____
		Gauges: Qty _____
Lock screws? Yes _____	No _____	Lock screw function: _____
Special material requirements:		_____
Casing hanger:		
	Size:	_____
	Type:	_____
	PSL:	_____
	PR:	_____
Temperature rating (Table 2):		_____
Material class (Table 3):		_____
Retained fluid corrosivity (Table A.1):		_____
External coating? No _____	Yes _____	If yes, type: _____
Internal coating? No _____	Yes _____	If yes, type: _____
Flange bolting requirements (Table 49)	Non-exposed _____	Exposed _____ Exposed (low strength) _____
Outlet inboard (studs): _____	(nuts): _____	
Outlet other (studs): _____	(nuts): _____	
Test and auxiliary equipment: (top and/or bottom) _____		
Wear bushings: _____		
Running and retrieving tools: _____		
Test plugs: _____		
Other requirements: _____		

Table A.10 — Wellhead equipment data sheet — Wellhead safety valves

Wellhead safety valves		
General		
	Special environmental conditions _____	Unusual ambient or operating temperatures, or atmospheric conditions conducive to corrosion or underwater use.
	Coating _____	
	Shipping instructions _____	
SSV/USV Valve		
	Performance test agency (PR 2 SSV/USV Valves) _____	
	Manufacturer _____	Model and type _____
	Size _____	
	Rated working pressure _____	
	Temperature range _____	
SSV/USV Actuator		
	Manufacturer _____	Model and type _____
	Cylinder rated working pressure _____	
	Operating pressure _____	Purchaser to specify available supply pressure, if applicable.
	Temperature range _____	
	Lock-open device _____	
	USV _____	Working water depth _____

Table A.11 — Wellhead equipment data sheet — Choke sizing

Application					
Fluid					
Quantity					
End connections / A&B Dimensions [a]					
Pressure rating/Inlet			Outlet		
Temperature rating					
Material class		Body		Trim	
PSL		PR			
Service conditions at		Max. flow (Units)	Normal flow (Units)	Min. flow (Units)	
Pressure	Inlet				
	Outlet or ΔP				
Temperature at inlet					
Oil	Flowrate				
	S.G. (if available)				
Gas	Flowrate				
	or G.O.R.				
	S.G. (if available)				
Liquid	Flowrate				
	S.G. (if available)				
Manual/actuated					
Actuator type/make/model					
Power source					
Manual override					
Position indication	Local		Remote/position transmitter		
Positioner					
Additional comments					

[a] See Figures 20 and 21.

Table A.12 — Wellhead equipment data sheet — Actuator and bonnet

	Quantity		Quantity		Quantity
Pneumatic		**Hydraulic**		**Electric**	
Diaphragm	Single	Conventional	Rising stem		
	Double		Non-rising stem		
		Retained fluid	Rising stem		
Piston	Single		Non-rising stem		
	Double	Wirecutter		Wire/cable size	
		Self-contained		Stand-alone power source	

Supply requirements/specifications

Pneumatic
Availability _____ MPa (psi)
Max. _____ Min. _____
Clean air _____
Nitrogen _____
Well gas _____ non-NACE _____
Other _____ NACE _____

Hydraulic
Availability _____ MPa (psi)
Max. _____ Min. _____
Well fluid
non-NACE _____ NACE _____
Self-contained _____
Other _____

Electric
Voltage _____
DC _____ AC _____ Phase _____ Frequency _____
Current available _____
Other _____

Actuator requirements

Specifications	**Actuator**
Temperature rating (Table 2)	
Retained fluid (Table A.1)	
Materials class (Table 3)	
External coating? No _____ Yes _____	
If yes type _____	

Field data
Customer _____
Field location _____
Platform _____
Well No. _____
Closed-in tubing head pressure _____ MPa (psi)

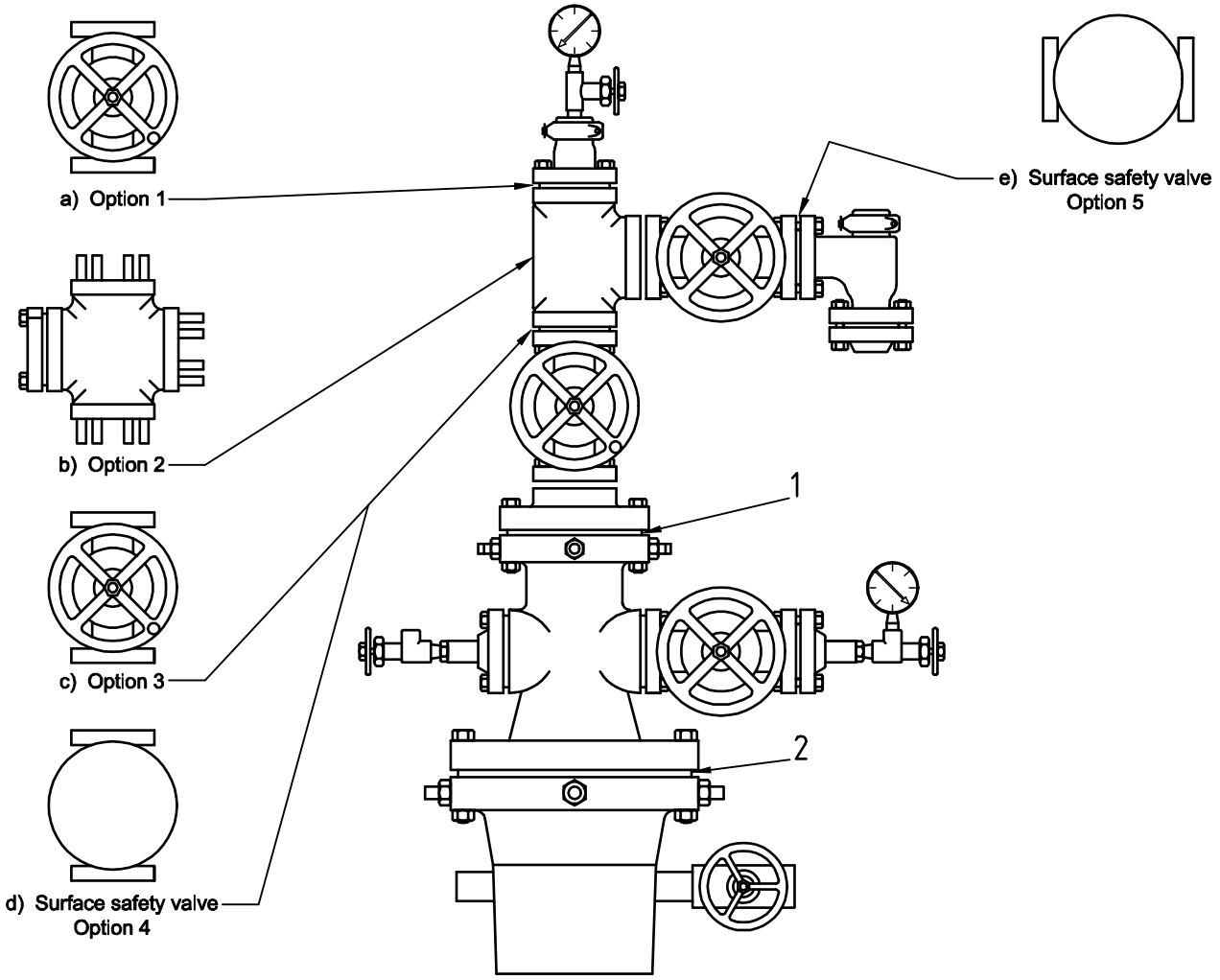
Accessories
Fusible hold-open device _____
Manual hold-open device _____
Quick exhaust valve _____
Position indication a) local _____
b) remote _____

Bonnet requirements
Size _____
Model _____
Maximum working pressure _____ MPa (psi)

Specification		**PSL**	
SSV PR2	_____	2	_____
		3	_____
		3G	_____
		4	_____

Material class:

Temperature rating:



Key

1 Tubing head top flange 34,5 MPs (5 000 psi)

2 Casing head top flange 20,7 MPa (3 000 psi) or 34,5 MPa (5 000 psi)

Typical programmes

Casing programme mm (in)	**Bit programme** mm (in)	**Casing head top flange** mm – MPa (in – psi)	**Tubing head top flange** mm – MPa (in – psi)
219,1 (8 5/8) × 139,7 (5 1/2)	200,0 (7 7/8)	279 – 20,7 (11 – 3 000)	179 – 34,5 (7 1/16 – 5 000)
244,5 (9 5/8) × 177,8 (7)	215,9 (8 1/2) or 222,2 (8 3/4)	or	
273,1 (10 3/4) × 193,7 (7 5/8)	250,8 (9 7/8)	279 – 34,5 (11 – 5 000)	

Figure A.1 — Typical wellhead and tree configuration 34,5 MPa (5 000 psi) rated working pressure

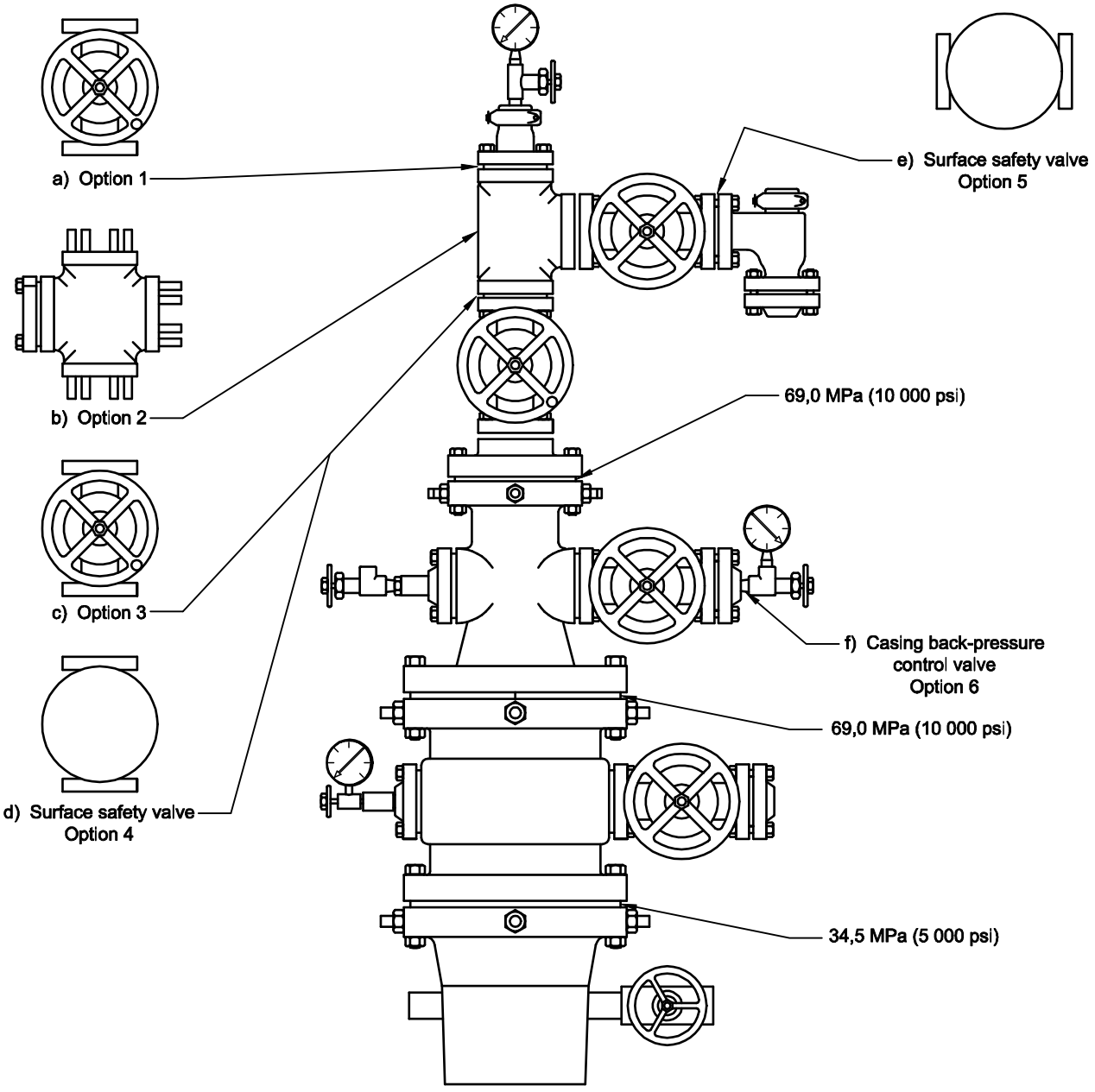


Figure A.2 — Typical wellhead and tree configuration 69,0 MPa (10 000 psi) rated working pressure

Typical programmes (metric)

Casing programme mm	**Bit programme** mm	**Casing-head housing top flange** mm – MPa	**Casing-head spool top flange** mm – MPa	**Tubing-head top flange** mm – MPa
406,4 × 273,1 × 193,7	374,7 × 250,8 or 241,3	425 – 34,5	279 – 69,0	179 – 69,0
406,4 × 298,5 × 244,5 × 177,8 Liner	374,7 × 269,9 × 215,9	425 – 34,5	346 – 69,0	179 – 69,0
			279 – 69,0	
339,7 × 244,5 × 177,8	311,2 × 215,9 × 152,4	346 – 34,5	279 – 69,0	179 – 69,0
273,1 × 193,7 × 127,0	250,8 × 165,1	279 – 34,5	279 – 69,0	179 – 69,0

Typical programmes (US customary units)

Casing programme in	**Bit programme** in	**Casing-head housing top flange** in – psi	**Casing-head spool top flange** in – psi	**Tubing-head top flange** in – psi
16 × 10 $^{3}/_{4}$ × 7 $^{5}/_{8}$	14 $^{3}/_{4}$ × 9 $^{7}/_{8}$ or 9 $^{1}/_{2}$	16 $^{3}/_{4}$ – 5 000	11 – 10 000	7 $^{1}/_{16}$ – 10 000
16 × 11 $^{3}/_{4}$ × 9 $^{5}/_{8}$ × 7 Liner	14 $^{3}/_{4}$ × 10 $^{5}/_{8}$ × 8 $^{1}/_{2}$	16 $^{3}/_{4}$ – 5 000	13 $^{5}/_{8}$ – 10 000	7 $^{1}/_{16}$ – 10 000
			11 – 10 000	
13 $^{3}/_{8}$ × 9 $^{5}/_{8}$ × 7	12 $^{1}/_{4}$ × 8 $^{1}/_{2}$ × 6	13 $^{5}/_{8}$ – 5 000	11 – 10 000	7 $^{1}/_{16}$ – 10 000
10 $^{3}/_{4}$ × 7 $^{5}/_{8}$ × 5	9 $^{7}/_{8}$ × 6 $^{1}/_{2}$	16 – 5 000	11 – 10 000	7 $^{1}/_{16}$ – 10 000

Figure A.2 — Typical wellhead and tree configuration 69,0 MPa (10 000 psi) rated working pressure
(continued)

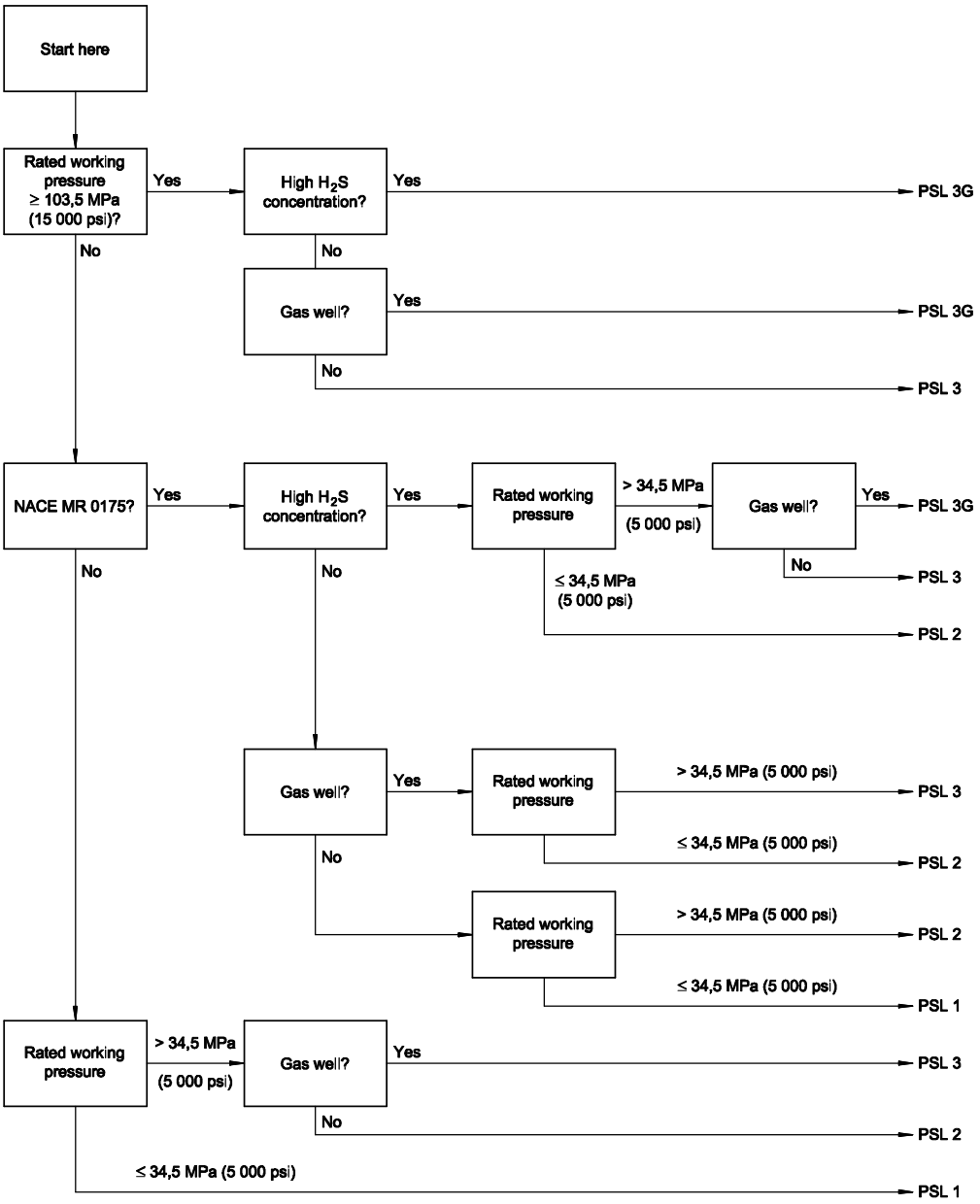


Figure A.3 — Recommended minimum PSL for primary parts of wellhead and christmas tree equipment