

DEP SPECIFICATION

**SELECTION OF MATERIALS FOR UPSTREAM
EQUIPMENT
(AMENDMENTS/SUPPLEMENTS TO
ISO 15156:2015)**

DEP 39.01.10.12-Gen.

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DESIGN AND ENGINEERING PRACTICE

DEM1



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PART I INTRODUCTION

1.1 SCOPE

This DEP specifies requirements and gives recommendations for selection of materials in oil and gas production systems from the reservoir to the export point.

This DEP does not include requirements/recommendations for structural steel for offshore platforms or superstructures, instrumentation or packaged equipment.

Requirements for instrument tubing used in instrumentation and packaged equipment are included in this DEP. Requirements for pressurized hydrocarbon-containing components in packaged equipment are also included in this DEP.

This DEP is intended to cover materials selection for offshore, onshore and subsea facilities. Materials selection for onshore facilities situated close to marine environments (within 10 km (6.2 mi)), for facilities in swamp areas or brackish waters, and for locations exposed to wind borne salt contamination, should be based on offshore requirements.

Selection of appropriate materials and design is necessary to avoid catastrophic or sudden failure mechanisms such as stress corrosion cracking, hydrogen embrittlement, (corrosion) fatigue, and low temperature embrittlement.

This DEP is not intended as a purchasing document.

This DEP is based on ISO 15156:2015. Part IV of this DEP amends, supplements and deletes various clauses of ISO 15156:2015. Part IV follows the clause numbering of ISO 15156:2015 for easy reference.

All clauses of ISO 15156:2015 not modified by this DEP remain valid as written.

This DEP contains mandatory requirements to mitigate process safety risks in accordance with Design Engineering Manual (DEM) 1 – Application of Technical Standards.

This is a revision of the DEP of the same number dated February 2017; see (1.5) regarding the changes.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by Shell GSI, the distribution of this DEP is confined to Shell companies and, where necessary, to Contractors and Manufacturers/Suppliers nominated by them. Any authorised access to DEPs does not for that reason constitute an authorisation to any documents, data or information to which the DEPs may refer.

This DEP is intended for use in upstream wells and facilities related to exploration and production. This DEP may also be applied in other similar facilities.

When DEPs are applied, a Management of Change (MOC) process shall be implemented; this is of particular importance when existing facilities are to be modified.

If national and/or local regulations exist in which some of the requirements could be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regards to the safety, environmental, economic and legal aspects. In all cases, the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations. The Principal may then negotiate with the Authorities concerned, the objective being to obtain agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

The **Contractor** is the party that carries out all or part of the design, engineering, procurement, construction, commissioning or management of a project or operation of a facility. The Principal may undertake all or part of the duties of the Contractor.

The **Manufacturer/Supplier** is the party that manufactures or supplies equipment and services to perform the duties specified by the Contractor.

The **Principal** is the party that initiates the project and ultimately pays for it. The Principal may also include an agent or consultant authorised to act for, and on behalf of, the Principal.

The word **shall** indicates a requirement.

The capitalised term **SHALL [PS]** indicates a process safety requirement.

The word **should** indicates a recommendation.

The word **may** indicates a permitted option.

1.3.2 Specific Definitions

Term	Definition
Sour Service	Exposure to oilfield environments that contain H ₂ S and can cause cracking of materials by the mechanisms referred to in ISO 15156 (equivalent to NACE MR 175).

1.3.3 Abbreviations

Term	Definition
ABS	Acrylonitrile Butadiene Styrene
CA	Corrosion Allowance
CC	Crevice Corrosion
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CSCC	Chloride Stress Corrosion Cracking
CTDM	Casing and Tubing Design Manual, WS.38.80.31.31-Gen.
DCAF	Discipline Controls and Assurance Framework
EPDM	Ethylene Propylene Diene Monomer
GC	Galvanic corrosion
GRP	Glass-Reinforced Plastic
HAZ	Heat Affected Zone
HE	Hydrogen Embrittlement
HIC	Hydrogen-Induced Cracking (also called step-wise cracking, SWC)
HIP	Hot Iso-static Pressed
HPHT	High pressure and high temperature

Term	Definition
HRB	Brinell Hardness
HRC	Rockwell Hardness
IGSCC	Intergranular Stress Corrosion Cracking
LAS	Low alloy steel
NACE	National Association of Corrosion Engineers
NDT	Non-destructive Testing (also known as NDE)
NPNT	Normal pressure, normal temperature
OES	Optical Electron Spectroscopy
PASCC	Polythionic Acid Stress Corrosion Cracking
PE	Polyethylene
PH Ni	Precipitation hardened nickel alloy
PREN	Pitting Resistance Equivalent Number
PTFE	Polytetrafluoroethylene
PVC	Polyvinyl Chloride
PVDF	Polyvinylidene Fluoride
RTP	Reinforced Thermoplastic
SCC	Stress Corrosion Cracking
SLC	Service Life Corrosion (total estimated wall thickness reduction of carbon steel during the service life of the equipment)
SME	Subject Matter Expert
SMSS	Super Martensitic Stainless Steel
SMYS	Specified Minimum Yield Strength
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SSC	Sulphide Stress Cracking
SWC	Stepwise Cracking
SZC	Soft Zone Cracking
TSA	Thermally Sprayed Aluminium
UNS	Unified Numbering System

Term	Definition
WC	Tungsten carbide

1.4 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section or clause number is shown in brackets (). Other documents referenced by this DEP are listed in (Part V).

1.5 SUMMARY OF MAIN CHANGES

This DEP is a revision of the DEP of the same number dated February 2017. The following are the main, non-editorial changes:

Section/Clause	Change
General	DEP update to align with updates incorporated in ISO 15156:2015
Part II, Section 2	Added new section
Part II, Section 3	Added new section
Part II, Section 4	Added new section
Part II, Section 5, Item 6	Clarified the DEM 1 requirement further
Part II, Section 6.2.4, Item 1	Clarified the DEM 1 requirement further
Part II, Section 7.3, Item 1b	Clarified the DEM 1 requirement further
Part III, Section 2.3, Item 2	Clarified the DEM 1 requirement further
Part III, Section 2.7, Item 4	Clarified the DEM 1 requirement further
Part III, Section 2.8.2, Item 2	Clarified the DEM 1 requirement further
Part III, Section 2.12, Item 5	Clarified the DEM 1 requirement further
Part III, Section 3.2, Item 6	Clarified the DEM 1 requirement further
Part IV	Several tables added as amendments to ISO 15156:2015
Part IV	DEM 1 statements extracted from tables and converted into stand-alone statements

1.6 COMMENTS ON THIS DEP

Comments on this DEP may be submitted to the Administrator using one of the following options:

Shell DEPs Online (Users with access to	Enter the Shell DEPs Online system at https://www.shelldeps.com Select a DEP and then go to the details screen for
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Shell DEPs Online)	that DEP. Click on the "Give feedback" link, fill in the online form and submit.
DEP Feedback System (Users with access to Shell Wide Web)	Enter comments directly in the DEP Feedback System which is accessible from the Technical Standards Portal http://sww.shell.com/standards . Select "Submit DEP Feedback", fill in the online form and submit.
DEP Standard Form (other users)	Use DEP Standard Form 00.00.05.80-Gen. to record feedback and email the form to the Administrator at standards@shell.com .

Feedback that has been registered in the DEP Feedback System by using one of the above options will be reviewed by the DEP Custodian for potential improvements to the DEP.

1.7 DUAL UNITS

This DEP contains both the International System (SI) units, as well as the corresponding US Customary (USC) units, which are given following the SI units in brackets. When agreed by the Principal, the indicated USC values/units may be used.

1.8 NON NORMATIVE TEXT (COMMENTARY)

Text shown in italic style in this DEP indicates text that is non-normative and is provided as explanation or background information only.

Non-normative text is normally indented slightly to the right of the relevant DEP clause.

PART II GENERAL**1 AMENDMENT OF ISO STANDARD**

Part IV of this DEP is written as amendments and supplements to ISO 15156:2015. Wherever reference is made to ISO 15156, it shall be understood to mean ISO 15156:2015 as amended/supplemented by this DEP.

For ease of reference, the clause numbering of ISO 15156 has been used throughout (Part IV) of this DEP.

Clauses in ISO 15156, which are not mentioned in this DEP, shall remain valid as written.

2 ALTERNATIVE MATERIALS

1. The use of proprietary alloys or materials not included in the Tables of this DEP shall be subject to approval of the Materials and Corrosion Technical Authority of the Principal.
2. The materials selection of production systems shall refer to the corresponding table in this section.

3 ACCEPTABILITY OF MATERIALS

1. Acceptability of materials by qualification of materials or Manufacturer/Suppliers shall be determined in accordance with (Part VI, Appendix B).

4 WELDING

1. Refer to DEP 30.10.60.18-Gen. or DEP 30.10.60.32-Gen. as applicable, for requirements for welding of clad and weld overlay welded equipment.

5 GENERAL

1. For determination of concentrations of H₂S, refer to DEP 25.80.10.18-Gen.
2. The requirements of ISO 15156 all parts, supplemented by (Part IV) of this DEP, shall be complied with in any hydrogen sulphide (H₂S) producing environment which exceeds the environmental limits of either ISO 15156 or (Part IV) of this DEP over the lifecycle, whichever is lower.
 - a. For carbon and low alloys steels, the requirements of ISO 15156-2 and (Part IV) shall apply if the H₂S concentration present in the equipment over the lifecycle exceeds either 3.5 mbar (0.05 psi) partial pressure H₂S in the gas phase or 10 ppm_{mass} in any aqueous phase.
3. When H₂S is present, but concentrations of H₂S are below 3.5 mbar (0.05 psi) partial pressure H₂S in the gas phase or 10 ppm_{mass} in any aqueous phase, the following shall apply:
 - a. Refer to DEP 39.01.10.11-Gen., clause 7.3.3 for the likelihood of hydrogen-induced cracking (HIC) for life cycles greater than 25 years and for steel wires in flexible pipes.
 - b. The suitability of high strength low alloy steels with AYS > 965 MPa (140 ksi) and exposed to H₂S shall be demonstrated, even for Region 0.
 - i. Refer to ISO 15156-2 for determining resistance to hydrogen embrittlement and SSC.
 - c. For the sulphide stress cracking (SSC) and stress corrosion cracking (SCC) resistance of alloys of modified 13Cr-1Mo and 13Cr with SMYS > 655 MPa (95 ksi) refer to the appropriate Wells Standard.

4. When assessing material suitability for design, the in-situ pH and H₂S partial pressure shall represent both the intended normal exposures during the service life and exposures expected to occur during one of the following:
 - a. an unintended process or treatment upset;
 - b. as a result of salt deposition;
 - c. a stratified flow condition;
 - d. as a result of completion leakage into the first well annulus;
 - e. production of completion and spent stimulation fluids back to the host facility.
5. When conversions between sodium chloride concentration in mg/l and g/l are made, the atomic weights of sodium and chloride shall be used (Cl- amounts to 61 % by mass of NaCl).

In ISO 15156 and in (Part IV) of this DEP, concentrations of sodium chloride in the corrosive phases are expressed as chloride concentrations [Cl-] in mg/l, whereas in (Part III), they are expressed as sodium chloride concentrations [NaCl] in g/l.

6. Molybdenum disulphide SHALL [PS] not be used with any of the following alloys:
 - a. non-sour carbon steels (i.e., that do not meet the requirements of ISO 15156-2);
 - b. martensitic stainless steels (e.g., 410, F6NM, CA6NM);
 - c. ferritic stainless steels (e.g., 405, 430);
 - d. austenitic stainless 300 series;
 - e. precipitation hardened stainless steels and nickel alloys (e.g., 17-4PH, Alloy 718).

Molybdenum disulphide used as a filler in a cured non-metallic coating (e.g., 10 % MoS₂ in PEEK), or alloy type not listed above are exempted from this requirement.
7. In corrosive service, CRA piping should be selected for small bore pipework ND50 (NPS 2) and below to minimise lifecycle cost.

6 REQUIREMENTS FOR SPECIFIC MATERIAL GROUPS

6.1 VESSELS

1. For vessels, internal protective coatings may be applied to protect carbon and low alloy steels against HIC or stepwise cracking, provided that it is possible to monitor HIC growth by non-destructive testing (NDT).

6.2 STAINLESS STEELS (PREN >13 AND Fe > 50 %)

6.2.1 High chloride exposures

1. The production stream phase behaviour shall be reviewed during detailed design to identify whether flashing conditions or salt deposition from carryover fluids can take place, which could lead to localised concentration of fluid salinity and cracking of stainless steels.
2. If localised concentration of fluid salinity can occur, either a salinity of 250 g/l (15.6 lb/ft³) (expressed as NaCl) or the greater value equivalent to salt saturation in water at operating conditions SHALL [PS] be used when selecting and testing the material.
3. All testing involving halides shall be done in representative water chemistry.
4. The temperature thresholds given in Table 1, Columns 1 and 2 shall be used to assess the following:
 - a. the risk of external pitting and crevice corrosion in offshore and onshore salt laden oxygenated environments;

- b. the requirements for mitigation against external pitting or crevice corrosion, if deemed necessary.
 - i. refer to (Part II, 7.3, item 1.a) for external Chlorides Stress Corrosion Cracking.
- 5. The temperatures given in Table 1, Column 3 shall be used as default values for the basis of design where no mitigation against external chloride stress corrosion cracking (CSCC) is required.
- 6. Application of stainless steels at temperatures given in Table 1, Column 4 shall require mitigation against CSCC.
- 7. Application of stainless steels at temperatures given in Table 1, Column 5 shall require mitigation against CSCC, and be subject to approval by the Materials and Corrosion Technical Authority of the Principal.
- 8. The risk associated with use of stainless steel types not covered in Table 1 shall be subject to approval of the Materials and Corrosion Technical Authority of the Principal.

Table 1 Application limits for stainless steels in salt laden, oxygen contaminated exposures ⁽⁶⁾

	1	2	3	4	5
Stainless steel type⁽¹⁾	Threshold for pitting corrosion	Threshold for crevice corrosion	Negligible likelihood of CSCC	Likelihood of CSCC at high chloride concentration⁽²⁾	Significant likelihood of CSCC
316L ⁽³⁾	5 °C (41 °F)	<0 °C (<32 °F)	<20 °C (<68 °F)	20 °C -50 °C (68 °F -122 °F)	>50 °C (>122 °F)
6Mo	50 °C (122 °F)	30 °C (86 °F)	<100 °C (<212 °F)	100 °C -120 °C (212 °F -248 °F)	>120 °C (>248 °F)
22Cr Duplex ⁽⁴⁾	40 °C (104 °F)	15 °C (59 °F)	<70 °C (158 °F)	70 °C -100 °C (158 °F -212 °F)	>100 °C (>212 °F)
25Cr Super-duplex ⁽⁵⁾	60 °C (140 °F)	30 °C (86 °F)	<80 °C (176 °F)	80 °C -100 °C (176 °F -212 °F)	>100 °C (>212 °F)
NOTES: 1. Table gives requirements for generic stainless steel types. Higher temperature limits could be acceptable for specific stainless steel materials or conditions, subject to review by Materials and Corrosion Technical Authority of the Principal. 2. High concentration could be due to chloride deposition from evaporation, or deposition of salt laden deposits (scales, sand). 3. Based on minimum Molybdenum content of 2 %. Higher temperatures may be validated at higher Mo content. 4. Based on PRE _N > 34. 5. Based on PRE _N > 40. 6. Exposures where wet salt deposit or halides (chlorides) above 200 ppm are present and oxygen contamination in the aqueous phase could be above 20 ppb, including exposures to salt laden moist air, injection water, residual hydrotest water, and cooling waters.					

- 9. Materials selection shall include the condition of external salt deposition in marine service, and for onshore in high salinity locales from conditions such as salt laden sand.
- 10. Contact of zinc with safety critical stainless steel equipment SHALL [PS] be prevented.
This is to avoid liquid metal embrittlement. Contact includes zinc containing coatings and contamination by zinc in fire scenarios from other equipment, but not electroplated zinc or zinc-nickel fasteners.

6.2.2 Martensitic stainless steels

1. Application of weldable 13Cr (SMSS) shall be validated by a test program for intergranular stress corrosion cracking (IGSCC) at process conditions that are subject to approval of the Principal.

6.2.3 Austenitic and duplex stainless steels (<6 % Mo)

1. Austenitic stainless steels containing lower chromium, nickel and molybdenum than AISI 316L shall not be applied.
2. For additional requirements for 22Cr Duplex and 25Cr Super-duplex stainless steels, refer to DEP 30.10.02.35-Gen.

6.2.4 Precipitation hardened stainless steels

1. Precipitation hardened stainless steels SHALL [PS] not be used in applications and environments listed in (Appendix A).

6.3 NICKEL ALLOYS (PREN > 26 AND Fe < 50 %)

1. For application of UNS N07718 (Alloy 718), UNS N07725 (Alloy 725) and UNS N07716 (Alloy 625+), refer to DEP 39.01.10.32-Gen.
2. Alloy N08825 (Alloy 825) shall be supplied with nickel content greater than 39 % and a PREN greater than 30.
3. Where galling resistance is required, one of the following shall be applied:
 - a. anti-galling compounds;
 - b. electroplating via immersion method rather than via brush application;
 - c. use of different materials for the two parts that come into contact, e.g., N06625, N07725;
 - d. an alternative anti-galling approach that assures a minimum difference in hardness of 25 HRB of the components.

6.4 GLASS REINFORCED PLASTICS

1. Refer to DEP 30.10.02.13-Gen. for requirements related to the choice of fibre and resin.
2. For use of GRP pipelines and piping, refer to DEP 31.40.10.19-Gen.

7 SPECIAL MATERIAL REQUIREMENTS**7.1 USE OF ISO 10423 (API 6A) MATERIAL CLASSES**

1. The low alloy steels referenced in Table 3 of ISO 10423 shall be one of the following:
 - a. UNS G41300 (AISI 4130);
 - b. UNS G86300 (AISI 8630);
 - c. ASTM A182 Grade F22 materials;
 - d. ASTM A694 Grades F56, F60 and F65.
2. Stainless steel castings shall be ASTM A743 Grade CA6NM.
3. Reference to "trim" in the context of ISO 10423 shall apply to pressure controlling parts of the component (e.g., seal faces, gates, stems, choke inserts, and mandrel hangers), but not to the body of the component.

7.2 WELDING CLAD AND WELD OVERLAY WELDED EQUIPMENT

1. Procedures involving welding or buttering of ferritic or martensitic materials with austenitic consumables shall be evaluated using a micro-hardness survey subject to approval by the Principal.

This is to assess whether a thin, hard, brittle zone of relatively high carbon has formed in the austenitic material immediately adjacent to the fusion boundary.
2. When carrying out buttering of ferritic or martensitic materials with austenitic consumables, the closure weld shall be made with UNS N06625 (Alloy 625).
3. The base metal and heat-affected zone (HAZ) may have a maximum hardness of 275 HV 10 (non-sour and sour service) if the equipment is fully clad.
 - a. Refer to ISO 15156-3, Clause A13.1.
4. Overlay weld cladding shall consist of a minimum of two layers.
5. The maximum iron content due to dilution of deposited Alloy 625 by the underlying carbon or low alloy steel at 1 mm (0.04s in) or less from the Alloy 625 surface, shall be 5 %.
 - a. This maximum may be increased to 10 % if justified by qualification testing.
6. Optical electron spectroscopy (OES) shall be used to determine weld dilution.

7.3 PROTECTION AGAINST CATASTROPHIC FAILURE MECHANISMS

1. Coatings or corrosion inhibition shall not be used as primary design barriers to stress corrosion cracking or corrosion fatigue.
 - a. Metal spray coatings including thermally sprayed aluminium (TSA) may be used for mitigation of external CSCC if the risk is demonstrated as ALARP.
2. Hard zones (HV > 325) detected by microhardness testing SHALL [PS] not be exposed to sour conditions or cathodic protection.

7.4 PROTECTION OF STAINLESS STEELS WITH ALUMINIUM

1. Stainless steel may be protected against external pitting and crevice corrosion by the following:
 - a. coating with TSA, refer to DEP 30.48.40.31-Gen.;
 - b. using sealed, 60 µm (2.4 mils) aluminium foil, refer to DEP 30.46.00.31-Gen.
2. The applicable temperature range for the use of aluminium foil under insulation shall be 50 °C to 200 °C (122 °F to 392 °F).
3. TSA shall not be used for protection of small-bore (<DN 50) (<NPS 2) components.
4. TSA shall not be applied to stainless steel in subsea applications.

7.5 SEALING MATERIALS

1. To prevent galvanic corrosion where metal-to-metal seals are used, the seal surface material shall be at least as noble as the surrounding surfaces.
 - a. For selection of elastomer seals, refer to DEP 30.10.02.13-Gen.

PART III MATERIALS SELECTION BY EQUIPMENT SYSTEM

1 INTRODUCTION

1.1 GENERAL

Part III includes materials requirements for process and utility equipment used in onshore, offshore, and subsea operations for exploration and production.

1. The application of materials listed in the material classes in (Appendix A, Table A.1) shall be subject to approval of the Principal.

2 PRODUCTION SYSTEMS

2.1 GENERAL

This clause covers downhole and facilities/topsides equipment that handle produced fluids, oil, gas, and produced water.

1. The materials selection of production systems shall refer to the corresponding table in this section.
2. For low temperature requirements of metallic materials, e.g., by process upsets, blow down or low ambient temperatures, refer to DEP 30.10.02.31-Gen.

2.2 DOWNHOLE TUBING AND LINERS

1. Table 2 shall be used for the selection of material for downhole tubing, production casing, and liners in production and injection exposures.
 - a. Other exposures including well brines, packer fluids, and stimulation acids, shall be included in the materials selection assessment.
 - b. Refer to (Appendix A) for other restrictions.
2. For specific well design requirements, refer to WS 38.80.31.31-Gen.
3. For water injection tubing materials selection, refer to (Part III, Section 4.1.7).
4. Refer to DEP 30.10.02.13-Gen. and DEP 31.40.10.19-Gen. for requirements for use of GRE with respect to combination of pressure and applied diameter, including limitations on wall thickness to diameter ratio.
5. When considering the use of GRE, limitations on the maximum string length in terms of load bearing capacity (ratio of strength to density) shall be included in the assessment.

Pressure limits in DEP 30.10.02.13-Gen. and DEP 31.40.10.19-Gen. refer to the maximum differential pressure across the tubing/lining/casing, e.g., internal overpressure (weep or burst failure mode) or external overpressure (collapse failure mode). They do not explicitly address load bearing capacity.

6. Use of GRE-lined carbon steel (CS) tubing shall be limited to products qualified by testing or subject to approval of the Principal.
 - a. Smaller diameter (e.g., 127 mm (5 in)) GRE-lined CS may be qualified by larger diameter product (e.g., 178 mm (7 in)).
 - b. Chemical compatibility shall be assessed, including the effects of stimulation acids and the impact of gas depressurization.
 - c. In deviated wells, the threat of wear shall be assessed, and other approved tubing materials installed at kick-off points if needed.
7. The use of carbon steel shall include all of the following:

- a. an assessment of service life corrosion (SLC);
 - b. the required wall allowance during the well life;
 - c. the ability of threaded connectors to withstand SLC for the anticipated well life duration.
8. Downhole corrosion inhibition, either continuous above the deepest injection point or batch above the point of liquid fill, may be used to reduce SLC when using CS tubing.
 9. Coated tubing shall not be used for improving corrosion time to failure.
 10. Coated production tubing, either carbon steel or CRA, may be considered for the following:
 - a. as a mitigation of work over costs (e.g., reduced fishing);
 - b. enhanced tubing reuse;
 - c. improved flow performance.

Table 2 Downhole production tubing, liners, and casing¹

Production	Conditions				Material
	SLC ⁽⁶⁾	Temp.	Sour regions H ₂ S ⁽²⁾	NaCl ⁽⁹⁾	
	mm (in)	°C (°F)	mbar (psi)	g/l	
Oil wetting of walls (Non-corrosive service)	<3 (<1/8)	<200 (<392)	Regions 0 or 1	Any	CS, ISO 11960, any strength grade up to 965 MPa (140 ksi) AYS (e.g., P110).
Water contact with walls (Corrosive or sour service)	<3 (<1/8)	<200 (<392)	Region 0	Any	CS, ISO 11960, any strength grade up to 965 MPa (140 ksi) AYS (e.g., P110).
Water contact with walls (Corrosive or sour service)	<3 (<1/8)	<200 (<392)	Region 1	Any	CS, ISO 11960, any group 2 grade, plus any grade per ISO 15156-2 Table A.3 temperature limits ⁽³⁾
	<3 (<1/8)	<200 (<392)	Regions 2 or 3+	Any	CS, ISO 11960 Q+T grades with hardness ≤ 250 HV 10 (≈ 22HRC) and C90 and T95 grades ⁽³⁾
	<3 (<1/8)	80-200 (176-392)	Regions 2 or 3+	Any	CS, ISO 11960 Grade P110 or other ISO 11960 CS with max. 965 MPa (140 ksi) yield strength.
	<3 (<1/8)	110-200 (230-392)	Regions 2 or 3+	Any	CS ⁽⁵⁾ , ISO 11960 Grade Q-125 or other ISO 11960 CS ⁽⁵⁾ with max. 1035 MPa (150 ksi) yield strength.
Water contact with walls (Corrosive sweet service, e.g., "non-sour" service)	N/A	<170 (<392)	<1.6 (<0.02)	<165	13CrL80 13Cr Modified with 1 % Mo
Water contact with walls (Corrosive sour service)	N/A	<140 (<284)	<3.5 (<0.05)	<165	13CrL80, 13Cr (13-5-2 ⁴) (composition)). See WS 38.80.31.31-Gen. for approval requirements for broader application limits. Exposure to be limited to pH ≥ 3.5.
	N/A	<170 (<338)	<10 (<1.5)	<20	
	N/A	<200 (<392)	<20 (<0.30)	<250	22Cr duplex stainless steel (860 – 965 MPa (125 -140 ksi))

Production	Conditions				Material
	SLC ⁽⁶⁾	Temp.	Sour regions H ₂ S ⁽²⁾	NaCl ⁽⁹⁾	
	mm (in)	°C (°F)	mbar (psi)	g/l	
	N/A	<200 (<392)	<100 (<1.45)	<250	25Cr super-duplex stainless steel (860 – 965 MPa (125 -140 ksi))
	N/A	<200 (<392)	<5500 (<80)	<250	SM 2535 (860 – 965 MPa (125 - 140 ksi))
	N/A	<200 (<320)	<14,000 (<203)	<250	Alloy 825 (860 – 965 MPa (125 - 140 ksi))
	N/A	<160 (<320)	<14,000 (<203)	<250	Alloy 28 (860 – 965 MPa (125 - 140 ksi))
	N/A	<200 (<392)	<36,000 (<522)	<250	Alloy 28 (PCO ₂ <25 bar (365 psi)) (860 – 965 MPa (125 -140 ksi))
	N/A	<200 (<392)	<80,000 (<1160)	<250	Alloy 2550/G3
	N/A	<280 (<568)	<120,000 (<1740)	<250	Alloy C276/C22/G50
Wet/dry oil/condensate	N/A	<110 (<230)	Any	No limit	GRE lined CS (Host pipe to be as required for sour service.)
	N/A	<100 (<196)	Any	No limit	GRE
NOTES: 1. For welded product limitations, see Table 3. 2. SSC regions as defined in Figure 1 of ISO 15156-2. H ₂ S pressures refer to partial pressures of H ₂ S. Refer to ISO 15156-1. Where no gas phase is present, the fugacity to be substituted for the partial pressure. For SSC Region 4 refer to requirements in WS 38.80.10.10. 3. Where necessary, higher strength grades may be qualified for a specific application per CTDM requirements. 4. "13-5-2" alloys from API Spec 5CT CRA materials can be proprietary and may require testing under simulated well conditions per WS 38.80.10.10 requirements to confirm applicability for service. 5. In accordance with ISO 15156, Table A.3, Q-125 Types 1 and 2 based on Q & T, Cr-Mo chemistry to 1,036 MPa (150,259 psi) maximum yield strength. C-Mn steels shall not be used. 6. SLC determines the excess wall allowance beyond that needed for design per the well's design standards. It is Not Applicable (N/A) to CRA usage. 7. Includes associated strength grades to a maximum 655 MPa (95 ksi) yield. 8. ANY on NaCl means <250, not proven for saturated conditions.					

2.3 CASING

1. Corrosion shall be controlled by the use of one of the following:
 - a. oil base fluids;
 - b. brines using stable pH buffers, oxygen scavengers, and biocides (below 100 °C (212 °F)).
2. Selection of production casing grade where a short-term exposure to produced fluids could occur SHALL [PS] be based on the carbon steel entries of Table 2.
3. Table 2 shall be used for the selection of casing continuously exposed to produce fluids where cracking or estimated corrosion of the casing might compromise well integrity.

4. External corrosion threats to casing should be assessed, with appropriate mitigation measures implemented: e.g., cement integrity, cathodic protection or sacrificial casing.

2.4 TREES AND DOWNHOLE EQUIPMENT

1. Table 3a shall be used for the selection of suitable materials for trees, refer to the restrictions noted in (Appendix A).
2. The materials for construction of subsea tree flow loops shall be carbon steel clad with Alloy 625, solid super duplex stainless steel or solid AISI 410 stainless steel, within the environmental limits of these materials as specified in Table 3b.
3. For API Class DD and higher, where there is potential for crevice corrosion, sealing surfaces shall be overlaid with Alloy 625 in accordance with Table 3a.
 - a. Refer to DEP 39.01.10.32-Gen. for requirements for precipitation hardened nickel alloys.
 - b. For subsea trees, refer to (Part III, Section 7).
4. Requirements to address elemental sulphur deposition shall be subject to approval of the Materials and Corrosion Technical Authority of the Principal.
5. Table 3 shall be used for all materials listed in classes in API 6A DD, EE, FF and HH, refer to (Part IV) and ISO 15156.

Table 3a Trees and wellhead equipment

API 6A material class	Typical service	Typical well location	Max P(H ₂ S)	Max temp.	NaCl	SLC	Tree and wellhead components						
			mbar (psi)	°C (°F)	g/l	mm	Xmas tree body	Wellhead & annular valves body	Valves trims		Tubing hanger	Casing hanger	Nuts/bolts
AA	Normally no flow ³ or meet the SLC	On/Offshore	3.5 (0.05)	Any	Any	<3	LAS up to 965 MPa (140ksi) AYS		Carbon steel		LAS up to 965 MPa (140ksi) AYS	Refer to (Part III, 2.12)	
BB	Producer, Onshore Water injector	On/Offshore		140 (284)	<165		LAS up to 965 MPa (140ksi) AYS		17-4PH+WC 410+WC	410			
CC ¹	Non-DEP standard, select FF												
DD	Normally no flow ³	On/Offshore	Any	Any	Any	<3	Sour LAS					Refer to (Part III 2.12)	
EE	Producer, hydrocarbon injectors	On/Offshore	27580 (400) ⁴	149 (300) ⁴	<250	<3	Sour LAS	Sour LAS	PH Ni Alloy +WC	PH Ni Alloy	Sour LAS, PH Ni alloy		
	Water injector ⁶	On/OffshoreS ubsea									Sour LAS, PH Ni alloy		
FF-0.07 ²	Producer, Hydrocarbon injectors ⁵	On/Offshore	5.17 (0.075)	140 (284)	<165	-	410, F6NM, CA6NM		410+WC,	410,	410, F6NM		
			5.17 (0.075)	200 (392)	<20	-			PH Ni Alloy +WC	PH Ni Alloy			

API 6A material class	Typical service	Typical well location	Max P(H ₂ S)	Max temp.	NaCl	SLC	Tree and wellhead components						
			mbar (psi)	°C (°F)	g/l	mm	Xmas tree body	Wellhead & annular valves body	Valves trims		Tubing hanger	Casing hanger	Nuts/bolts
HH		Subsea, On/Offshore	27580 (400) ⁴	149 (300) ⁴	<250	-	Sour LAS +625 clad throughout		PH Ni Alloy +WC	PH Ni Alloy	Sour LAS +625 clad, PH Ni alloy	Sour LAS	
HH			Variable depending on least resistant alloy as per (Part IV)						Refer to (Part III, Section 7)				
HH	Water Injector (all type)		27580 (400) ⁴	Part III, section 4.1.7)	Any	-			PH Ni Alloy +WC	PH Ni Alloy	Sour LAS +625, PH Ni alloy	Sour LAS	
NOTES: 1. CC class would typically specify 17-4PH components, which, due to its sensitivity to H ₂ S, is not recommended to be used, even in sweet service (up to 35 mbar (0.05 psi) H ₂ S). 2. If the completion includes a downhole injection of corrosion inhibition (batch or continuous), the tolerable P _{H₂S} may be increased to 105 mbar (15 psi), subject to approval of the Materials and Corrosion Technical Authority of the Principal. 3. Specify A320-L7M/A 194-7M for fasteners that are directly exposed to sour environment as specified in ISO 15156-2 A.2.2.4. 4) Limited by the use of 718 alloy at the trims. Greater H ₂ S limits can be applied by specifying alloys with greater resistance to H ₂ S in line with (Part IV). 4. H ₂ S and temp limits based on commonly used 925/718 alloys in trims/hangers. Greater limits may be applied by specifying alloys with greater resistance to H ₂ S (per (Part IV) noting that the limit of the entire system is limited by the least resistant alloy in terms of H ₂ S, Temp or NaCl. 5. Control the oxygen in produced water re-injection well to <10ppb with 99 % compliance for selecting FF class tree. 6. EE tree may be considered provided that a carbon steel pipeline and downhole tubing has been selected in line with (Part III, Section 4.1.7).													

Table 3b Downhole accessories¹

Conditions				Material	Typical corresponding completion material
Temp	PH ₂ S	NaCl (chlorides)	Other		
°C (°F)	mbar (psi)	g/l			
Downhole components, sweet service					
Any	<3.5 (<0.05)	<200 (120)	SLC <3	9Cr-1Mo.	Carbon Steel
<140 (<284)	<3.5 (<0.05)	<165 (100)	SLC >6	410	13CrL80
<200 (<392)		<20 (12)	SLC >6		13CrL80
Downhole components, sour service					
<140 (<284)	<5 (<0.07)	<165 (100)	pH > 3.5	420 <22HRC	13CrL80
<200 (<392)		<20 (12)	pH > 3.5		
<149 (<300)	<2800 (<400)	<200 (120)		Alloy 718 or Alloy 925	Any tubing with 655 MPa (95ksi) SMYS
<232 (<450)	<27,580 < (400)	<300 (180)		Alloy 935	Any tubing with 655 MPa (95ksi) SMYS
<205 (<401)	<35,025 (<508)	<300 (180)		Alloy 945	Any tubing with 655 MPa (95ksi) SMYS
<232 (<450)	<35,025 (<508)	<230 (139)			Any tubing with 655 MPa (95ksi) SMYS
<240 (<392)	<51700 (<750)	<250 (150)		Alloy 725, Alloy 625	Any tubing with 655 MPa (95ksi) SMYS, GRE (Water injectors)
Springs					
<240 (<392)	<51700 (<750)	<250 (150)	SLC >6	MP35N	
Sand screen wire (for base pipe see Table 2)					
<120 (<248)	<3.5 (<0.05)	<250 (150)	SLC >6	316	Carbon steel, 13Cr
<160 (<320)	<14,000 (<203)	<250	SLC >6	825	CRA completions, sour grade CS completions
NOTES: 1. For welded components, refer to Table 3A. 2. For instrument line materials, refer to Table 2. 3. For subsea wellhead applications refer to (Part III, Table 26).					