

PETRONAS TECHNICAL STANDARDS

DESIGN AND ENGINEERING PRACTICE

MANUAL

SELECTION OF MATERIALS FOR LIFE CYCLE PERFORMANCE (EP) – UPSTREAM EQUIPMENT

PTS 39.01.10.12

DECEMBER 2010



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This revision of **PTS 39.01.10.12 – Selection of Materials for Life Cycle Performance (EP) – Materials Selection Process (Revision 1)** has been updated incorporating PETRONAS Lessons Learnt, Best Practice and new information issued by relevant industry code and standards. This is a major revision, which includes dividing the original PTS into two parts: PTS 39.01.10.11 addresses the material selection process and PTS 39.01.10.12. covers materials selection for specific equipment. The revision is so substantial that no attempt was made to highlight the changes.

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PREFACE

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1. INTRODUCTION

1.1 SCOPE

This new PTS was created by splitting PTS 39.01.10.11 into two PTSs. PTS 39.01.10.11 now only addresses the material selection process and PTS 39.01.10.12 (this PTS) covers materials selection for specific equipment.

This PTS specifies materials for production systems from the reservoir to the export point. It enables technically proven and economically acceptable materials selection for most equipment. It does not include structural steel for offshore platforms or superstructures, instrumentation (but does include instrument tubing) or packaged equipment. Guidance on detailed materials selection for complicated accessories, such as TRSSVs, chokes etc, is not included in this PTS. Materials for these accessories may be derived from adjacent bulk materials. However, caution should be exercised in such derivations, because functional requirements, such as leak resistance, may require the use of materials with a higher corrosion resistance for some sub-parts, possibly because of standardisation of equipment materials.

There are many equipment-based PTSs that contain materials-related information. It is the intent that PTS 39.01.10.11 and PTS 39.01.10.12 will contain all materials selection related information and that the equipment-related PTSs refer to this PTS. It should be recognised that this will be a gradual transition, which will be realised as other PTSs are updated. At this time, detailed information in PTS 31.21.01.31 regarding heat exchangers is referred to. In the event of conflict the Principal shall be consulted.

This PTS does not cover every contingency. It is the responsibility of the user to recognise when additional resources need to be brought to bear on a question or decision. It should also be noted that this PTS is not intended as a purchasing document and does not include inspection and testing requirements. Such requirements are addressed elsewhere in certain PTSs.

If conditions are encountered that are not adequately covered in this PTS, or if the user wishes to consider less conservative materials choices in the interest of potential cost savings, the Principal's materials and corrosion specialists should be consulted.

Packaged equipment is generally excluded from the scope of this PTS but where some of the components of the packages are included in this PTS (e.g. instrument tubing on packaged equipment), this PTS shall be followed. Materials selection for other parts of packaged equipment shall be subject to the approval of the Principal's materials and corrosion specialist.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

Unless otherwise authorised by PETRONAS, the distribution of this PTS is confined to companies forming part of PETRONAS or managed by a Group company, and to Contractors and Manufacturers/Suppliers nominated by them.

This PTS is intended for use in exploration and production facilities. For refineries and chemical plants, reference should be made to PTS 30.10.02.11 (which, even though it is originally intended for downstream use, contains useful information that can in many cases be applied to upstream equipment).

When PTSs are applied, a Management of Change (MOC) process should 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 may be more stringent than in this PTS, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regard 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 PTS 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 PTS 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, installation, and commissioning or management of a project or operation of a facility. The Principal might sometimes undertake all or part of the duties of the Contractor.

The **Manufacturer** 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 its design and construction. The Principal will generally specify the technical requirements. The Principal might also include an agent or consultant, authorised to act for the Principal.

The word **shall** indicate a requirement.

The word **should** indicate a recommendation.

1.3.2 Specific definitions

Sour service exposure to oilfield environments that contain H₂S and can cause cracking of materials by the mechanisms addressed by ISO 15156-1

1.4 ABBREVIATIONS

ABS	Acrylonitrile Butadiene Styrene
c.a.	Corrosion allowance
CE	Carbon Equivalent
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CSCC	Chloride Stress Corrosion Cracking
EOR	Enhanced Oil Recovery
EPDM	Ethylene Propylene Diene Monomer
FEED	Front End Engineering Design
GRP	Glass Reinforced Plastic (Fibreglass). Also known as FRP (Fibre Reinforced Plastic) or GRE (Glass Reinforced Epoxy)
HAZ	Heat-Affected Zone
HIC	Hydrogen-Induced Cracking (also called Step-Wise Cracking, SWC)
HP/HT	High Pressure / High Temperature
HRC	Rockwell Hardness
IRHD	International Rubber Hardness Degrees
MESC	Materials and Equipment Standards and Code
NACE	National Association of Corrosion Engineers
NAPRE	Nickel Alloy Pitting Resistance Equivalent
NAPRE _w	Nickel Alloy Pitting Resistance Equivalent for weld metal
OU	Operating Unit
PASCC	Polythionic Acid Stress Corrosion Cracking
PE	Polyethylene
PIR	Polyisocyanurate Foam (sections, slabs)
PRE _N	Pitting Resistance Equivalent Number (N) = % Cr + 3.3 % Mo + 16 % N

PRE _w	Pitting Resistance Equivalent Number (W) = % Cr + 3.3 % (Mo + 0.5%W) + 16 % N
PVC	Polyvinyl Chloride
PVDF	Polyvinylidene Fluoride
PTFE	Polytetrafluoroethylene
PUR	Polyurethane Foam (sections, slabs)
PWC	Preferential weld corrosion
RTJ	Ring Type Joint
RTP	Reinforced thermal plastics
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 Mater Expert
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SSC	Sulphide Stress Cracking
TLP	Tension Leg Platform
TRSSV	Tubing-Retrieval Subsurface Safety Valve
TSA	Thermally Sprayed Aluminium
UHMW PE	Ultra High Molecular Weight Polyethylene
UNS	Unified Numbering System
WAG	Water Alternating Gas
WI	Water Injection
WPQ	Welding Procedure Qualification

2 GENERAL MATERIALS DESCRIPTIONS

2.1 MATERIALS GROUPS

2.1.1 General

A list of typical compositions and corresponding UNS numbers of materials used in upstream applications is given in Appendix 1.

2.1.2 Stainless steels

Although stainless steels are resistant to corrosion under certain conditions, their resistance is invariably limited by a combination of such factors as temperature, pH, chloride content, and presence of H₂S. This is particularly true for the resistance to pitting corrosion, crevice corrosion and stress corrosion cracking.

The resistance of stainless steels to pitting and crevice corrosion in low salinity brines, including aerated seawater, can to some extent be expressed by means of the Pitting Resistance Equivalent Number PRE_N. For other applications the advice of materials and corrosion experts should be sought. Pitting and crevice corrosion resistance can also be characterised by means of a critical temperature, although it is difficult to define specific temperatures as these depend on the exact conditions, which includes the composition of the seawater, turbulence and metal surface condition. The critical crevice corrosion temperatures (CCT) are lower than the critical pitting temperatures; the CCT decreases as the crevice is narrower. Conventional coatings are adequate to mitigate chloride pitting if chloride cracking is not an issue.

Due to stainless material's sensitivity to chloride content, the production stream phase behaviour shall be reviewed to ensure that flashing conditions, which will concentrate fluid salinity and typically occur at system pressure drops, are not present. In the event such flashing conditions are present, a salinity of 250 g/l shall be assumed when selecting the stainless material.

Ferritic and martensitic stainless steels such as those of the 13Cr family are susceptible to sulphide stress cracking (SSC) and therefore their application is limited to very low concentration of dissolved H₂S and strict hardness limitations apply, as defined by ISO 15156 and given in the tables in (3). Both the SSC and the pitting crevice corrosion resistances are strongly influenced by the pH of the environment, as indicated in several tables in chapter 3.

NOTE: NACE MR0175 is identical to ISO 15156.

The low temperature toughness of these materials is also limited, see PTS39.01.10.11. Appendix 6.

Martensitic stainless steels are split into three general categories:

- 13Cr - Conventional 13Cr steel, e.g., AISI 420;
- Alloyed 13Cr, e.g., ASTM A 182 Grade F6NM (forgings), ASTM A487 CA6NM (castings);
- S13Cr - Super 13Cr or Weldable Martensitic Stainless Steel (low-carbon weldable grades, often with added Ni and Mo alloy content). The use of welding for these materials shall be reviewed and approved by the Principal. Only high grade S13Cr shall be considered for welding. Laser welded pipe shall not be specified. The term 'Super 13Cr' has become well established for downhole tubing applications but is a misnomer as these alloys usually have less than 13 % Cr content.

Austenitic stainless steels can suffer from anodic stress corrosion cracking (SCC) types such as chloride SCC. Chloride SCC of AISI 316L can occur if the operating temperature rises above 60 °C (or 50 °C for offshore and coastal areas).

There is no issue with the classic form of SSC, although the presence of H₂S can aggravate the occurrence of anodic stress corrosion cracking. Low temperature is not a concern unless the temperature is lower than –105 °C.

Austenitic stainless steels can also suffer from polythionic acid stress corrosion cracking (PASCC), which can occur when these materials are in sour service and are exposed to air. Examples are cracking of UNS S31603 (AISI 316L) and UNS N08825 (Alloy 825) clad vessels in sour gas plants. PASCC is not related to the chloride level and can be prevented by reducing sensitization, e.g. through low carbon welding and postweld heat treatment

There is a risk of **external** chloride stress corrosion cracking (Chloride SCC, or CSCC) of stainless steel components in marine environments (offshore and coastal areas) and in some desert environments (high salinity sand with dewing condensation).

Use of austenitic stainless steels containing less chromium, nickel and molybdenum than AISI 316, such as AISI 304, shall not be applied except in certain specific environments, see Appendices 2 and 3, and any such use shall be approved by the Principal.

Austenitic/ferritic stainless steels (duplex stainless steels) can suffer for both SCC and SSC, hence hardness requirements apply and strict dissolved H₂S limits have to be followed as given in the tables in (3). CCCC of 22Cr duplex can occur if the operating temperature is above 80 °C although failures in service have only been experienced above 100 °C. 25 Cr super-duplex stainless steels are more resistant to CCCC but a limit of 110 °C is recommended for design or risk assessments. Tests at the UK National Physical Laboratory have shown both 22Cr duplex and 25Cr super-duplex stainless steels to be susceptible to CCCC at 80 °C under drop evaporation conditions which indicates that accumulation of salt deposits should be avoided.

Duplex stainless steels are also known to suffer from hydrogen induced stress cracking in certain condition. More detail and references can be found in PTS 39.01.10.11.

These materials are weldable, but welding procedures have to be carefully selected and qualified, and have to be strictly applied.

The minimum design temperature of duplex stainless steels is –50 °C; qualification for low temperature use shall be accomplished by Charpy impact testing at –50 °C (see also PTS 39.01.10.11). For thicknesses above 30 mm other test requirements are necessary, see PTS 30.10.02.31.

There are many different qualities of duplex stainless steel, with widely varying pitting resistance as characterised by the PRE_N values (see Appendix 1). The most common types of 22Cr duplex stainless steels are UNS S31803 (minimum PRE_N>30.5) and S32205 (minimum PRE_N>34.1). The 25Cr duplex stainless steels are sometimes called “super duplex stainless steels”, although some restrict the use of this term to the highest PRE_N valued materials. In this PTS the term super duplex stainless steel is applied to all duplex stainless steels with 25 % Cr. Common examples are listed in Appendix 1.

Super austenitic stainless steels (>6 % Mo).

Super austenitic stainless steels have a PRE_N similar to that of super duplex stainless steels, and as such have been use in seawater systems. However, the reduced yield strength, when compared to that of super duplex steels, often sees the later preferred for higher-pressure services. Typical material grades are UNS S31254, N08925, N08367, N08926, N08028.

To ensure corrosion resistance of welds nickel alloy filler with increased Mo, such as alloy 625, shall be used. These materials are difficult to cast, especially in large sections, without cracking. For this reason it is recommended that for valve and pump bodies 25Cr super duplex stainless steels should be used.

Precipitation hardening stainless steels tend to be susceptible to SSC and use of these materials shall be approved by the Principal, see also Appendix 2. These materials are not very resistant to pitting corrosion and pits can act as initiation sites for stress corrosion cracks. This applies in particular to the materials UNS S17400 (17-4PH) and UNS S15500 (15-5PH), the use of which shall be restricted more stringently than specified in ISO 15156. The sensitivity to SSC can in principle be controlled by means of a special double heat treatment as specified in ISO 15156-3, but experience has shown that it is very difficult to achieve proper heat treatment control. Therefore the use of these materials shall not be

considered for (potentially) sour environments and if under cathodic protection and shall in all cases be approved by the Principal.

2.1.3 Nickel alloys

These materials are known for their good performance at high temperatures and in corrosive conditions, including many sour service applications. The following additional restrictions apply.

Nickel alloys can suffer from intergranular corrosion; the limits can be determined by means of ASTM G 28.

UNS N07718 (Alloy 718) shall be specified in accordance with API 6A718. These materials have a limited galling resistance (a condition whereby excessive friction between high spots results in localised welding with subsequent splitting and a further roughening of rubbing surfaces of one or both of two mating parts). If this is a problem, a possible solution is to specify anti-galling compounds, electroplating, or to use different materials for the two parts that come into contact, e.g. N06625 and N07725. An alternative approach is to specify a minimum difference in hardness of 25 HRB of the components.

At present there are no comprehensive international standards, which cover the purchase requirements of Alloy 725 Inconel patent (UNS N07725) or Alloy 625+ (UNS N07716). These materials may suffer from similar issues to those that have been observed with Alloy 718, and as such, care should be taken during manufacturing and heat treatment, particularly for critical or highly loaded components.

2.1.4 Glass Reinforced Plastics

Glass-Reinforced Plastics (GRP, sometimes called Fibre-Reinforced Plastics, FRP) comprise glass fibres within a resin matrix, e.g. epoxy, vinyl ester, polyester, phenolic. In some cases glass fibres might be replaced by either carbon or aramid fibres. The choice of fibre and resin should be selected after full consideration of the service requirements in accordance with PTS30.10.02.13. GRP pipelines and piping shall be in accordance with PTS 31.40.10.19.

2.2 SPECIAL REQUIREMENTS

2.2.1 Use of ISO 10423 (API 6A) Materials Classes

Table 3 of ISO 10423 specifies "materials classes", which makes reference to carbon and low alloy steels, stainless steel and CRAs. Some of the materials classes are designated for sour service.

The same materials are also used for subsea piping on sleds and manifolds. In this context carbon steels are typically ASTM A182 Grades F56, F60 and F65, whereas low alloy steels are UNS G41300 (AISI 4130), UNS G86300 (AISI 8630) and ASTM A182 Grade F22 materials. AISI 4130 and 8630 materials shall be purchased to ASTM A812, A350, A694, or A707, depending on the application.

For the purpose of this PTS, it is assumed that in all cases where reference is made to stainless steel, 13Cr type stainless steels as described in (2.1.2) are intended. The use of such equipment is limited to low dissolved concentrations of H₂S irrespective of the sour service designation. The Principal's materials and corrosion expert shall be consulted, because there are no generally applicable guidelines that cover all materials, applications and manufacturers. Furthermore it shall be assumed that in all cases where CRAs are addressed, Alloy 625 (UNS N06625) will be used as the default material for all wellhead and subsea hardware; deviations shall be approved by the Principal.

Since very large valve bodies cannot be produced by means of forging, castings must be used. Such stainless castings are assumed to be ASTM A743 Grade CA6NM for the purpose of this PTS. Qualification procedures for such applications shall be approved by the Principal.

Where reference is made to "trim" in the context of ISO 10423, this applies to pressure controlling parts, i.e. seal faces, stems and mandrel hangers.

2.2.2 Welding of Alloy 625 clad and overlay equipment

UNS N06625 (Alloy 625) overlay welding is a commonly selected material for certain corrosive fluids and deserves some special mention on quality control. There will be some iron dilution during the welding process, so the clad layer will not comply with an UNS N06625 (Alloy 625) analysis after deposition. PTS30.10.60.18 shall apply. This includes the requirement to use a minimum of two layers to overlay. The maximum allowed iron content due to dilution of deposited Alloy 625 by the underlying carbon or low alloy steel at 1 mm or less from the Alloy 625 surface is 10 %; filler wires shall be selected and quality control carried out to ensure that this is achieved.

Any welding procedures of ferritic / martensitic materials with austenitic consumables require close scrutiny, because a hard, brittle zone of relatively high carbon could form in the austenitic material immediately adjacent to the fusion boundary. This brittle zone will be very sensitive to hydrogen embrittlement (hydrogen induced stress cracking, sulphide stress cracking) and even brittle fracture due to stress alone if the critical flaw size (as determined by means of CTOD tests) is exceeded. Direct exposure of such hard zones to sour conditions and cathodic protection shall be avoided; simply fulfilling ISO 15156 hardness requirements such as 250 HV 10 is not sufficient, because the brittle zone is so thin that it cannot be detected with the Vickers method of hardness testing.

For the same reason hydrogen embrittlement is a serious risk when UNS N06625 (Alloy 625) overlaid materials are welded using UNS N06625 (Alloy 625) buttering. The same alloy has even been used to butter non-clad low alloy steel forgings and martensitic stainless steels. Buttering is used to enable post weld heat treatment of reasonably sized components in order to achieve good toughness and hardness. By choosing a suitable butter material, the field "closure" weld can be made without requiring post weld heat treatment. However, the fusion line hardness and brittleness are exacerbated by the post weld heat treatment due to the formation of untempered martensite and carbide precipitation along the fusion line. To avoid this problem, welding procedures for such overlaid materials have been developed that involve buttering with selected low carbon low alloy steel consumables followed by a post weld heat treatment. The closure weld is made with UNS N06625 (alloy 625). Maximum hardness of 325 HV 10 in the base metal and HAZ are accepted for non-sour and sour service provided that the bore is fully clad (Ref. ISO 15156-3 clause A13.1).

2.2.3 Protection against catastrophic failure mechanisms

Catastrophic failure mechanisms such as stress corrosion cracking, (corrosion) fatigue and low temperature embrittlement shall be prevented by means of proper materials selection and design. Coatings or corrosion inhibition should not be used as barriers to stress corrosion cracking or corrosion fatigue during design. If operating temperatures change to the extent that the chloride stress corrosion cracking temperature limit is exceeded, the use of coating or aluminium foil may be considered, but shall be subject to proper management of change and approved by the technical authority. If approved, candidate coatings should have a design life at least as long as the design lives of the facilities – conventional coatings are not acceptable.

Metals in sour services shall conform to ISO 15156, and quality control shall be implemented to assure that these materials conform to the standard's material and fabrication requirements. When assessing material suitability, the pH and H₂S partial pressure shall represent not only normal life cycle exposures but also exposures as can reasonably be expected to occur during an upset or flow condition (e.g., normal packer fluid pH versus condensing water pH after a tubing to annulus leak, pH of flowline fluid versus condensing water pH during stratified flow).

An exception to the rule of not using coatings to protect equipment against potentially catastrophic failure is that it is considered acceptable to protect carbon and low alloy steels against hydrogen induced cracking (HIC) or stepwise cracking by means of coatings, provided that the coating integrity is ensured by means of a suitable maintenance program and that a program is in place to detect and monitor HIC formation and growth. For practical purposes this only applies to vessels.

2.2.4 Protection of stainless steels with thermally sprayed aluminium

Stainless steels can be protected against external pitting and crevice corrosion by means of coating with thermally sprayed aluminium (TSA). As an alternative, austenitic stainless steel may be cleaned with fresh water and, after being dried, wrapped in 100 % pure aluminium foil, approximately 60 µm thick. Joints and ends shall be taped with self-adhesive aluminium tape. This aluminium foil will act as both a barrier coat and inhibitor. The applicable temperature range for the use of aluminum foil under insulation is 50 °C to 200 °C for continuous service and 50 °C to 480 °C for cyclic conditions.

Achieving good external TSA coverage of small-bore (< DN 50) components is extremely difficult, so selecting a resistant material is the preferred option. If the consequence of failure is low, the decision may be taken to install a low-cost susceptible material and change it out if it fails. There has been some good experience with using (uncoated) materials at higher operating temperatures combined with very regular cleaning of the surface to prevent salt build-up, but this is not a recommended practice for new designs, as the sustainability of such practices is questionable.

2.2.5 Sealing materials

Where metal-to-metal seals are used, it is essential to prevent galvanic corrosion; therefore the seal surface material shall be at least as noble as the surrounding surfaces. Elastomer seals are addressed in (3.2.13).

3. MATERIALS SELECTION BY EQUIPMENT SYSTEM

3.1 INTRODUCTION

3.1.1 General

This section includes types of process and utility equipment found in exploration and production operations. For equipment not listed, advice should be sought from a materials specialist.

The materials options given are intended to be suitable for onshore, offshore or subsea operations.

Materials that require special care and that should be used in specific applications only are listed in Appendix 2.

All painting of equipment should be done in accordance with PTS 30.48.00.31.

Where materials standards are not specified in this PTS, or in the applicable equipment PTSs, PTS 30.10.02.11 shall be used to identify the appropriate materials standard.

If the corrosion rate is known from service experience or prediction, then the Service Life Corrosion (SLC) figure can be used for materials selection. Otherwise, basic operating condition data can be used to obtain possible materials options. For corrosive conditions not adequately described, a materials specialist should be consulted.

The SLC, which is applicable only to carbon steels, is the service life corrosion including the effects of corrosion control, if applied, and any excursions. The normal procedure is to work out the SLC without corrosion control; if this gives an acceptable SLC value no corrosion control is required. If the initial SLC figure is too high (from a technical or economic perspective) then it should be recalculated taking into account the effects of the selected corrosion control system and associated reliability or expected maintenance.

The environmental limits for production fluids, in terms of H₂S, temperature, chloride content, pH, etc., represent basic recommendations of the suitability of the material for such an environment. In some cases the actual limits of applicability of individual materials might be higher than those shown in the tables in the following sections. The limits quoted are based on the assumption that the pH of the environment is 3.5 for gas systems, unless otherwise stated. A pH of 3.5 is selected because this is the most severe condition for production operations (e.g. gas systems with only condensed water). A pH of 4.5 is selected in some cases as the most severe for oil production systems (see PTS 39.01.10.11).

NOTE: Lower pH environments occur for short periods of time during acidising and flow back of (partially) spent acids. If not properly controlled these conditions can lead to severe corrosion.

If the pH is expected to be higher (less acidic), some relaxation of these limits might be possible. Where needed, materials might be qualified for service outside the conditions indicated in the following sections by consulting a materials and corrosion specialist.

It is emphasised that materials selection depends on multiple variables that often interact. The applicability of materials in the multi-dimensional space of such factors as temperature, pH, and chloride content and dissolved H₂S concentration is not fully defined. The tables in this section typically list discrete combinations of factors for which the materials have been qualified. Extrapolation between different combinations of factors may only be done by the Principal's materials and corrosion experts, who can decide whether additional testing is required.

The Principal's materials and corrosion expert should be consulted on appropriate test methods (e.g. EFC 17) and guidance on interpretation of results. Generic alloy groups or individual alloys need separate qualification addressing items such as resistance to general corrosion, sulphide stress cracking, stress corrosion cracking, pitting, crevice corrosion, and galvanic effects.

3.2 PRODUCTION SYSTEMS

3.2.1 General

This section covers downhole and facilities/topsides equipment handling all produced fluids: oil, gas and produced water. The material selected for many items shall meet minimum toughness requirements at the minimum design temperature during blowdown conditions. The low-temperature limitations of materials are covered in detail by PTS 30.10.02.31. (which gives approximate minimum temperatures for different materials for guidance) and PTS 31.38.01.15. (which refers to ASME B31.3).

3.2.2 Downhole Tubing and Liners

Detailed production tubing material selection depends upon an analysis of the flow regime, corrosivity of the well fluids, materials properties and economic factors. Table 1 gives general guidelines on suitable materials depending upon the cumulative corrosion loss anticipated for the lifetime of the well and the anticipated environmental conditions.

SLC is used here as one of the factors in material selection, as a common approach used in all these tables. This is more difficult to apply in tubing where the effective "corrosion allowance" is typically 50 % of the wall thickness – this is a "rule of thumb": if there is 50 % of the wall thickness still remaining, it will be possible to pull the tubing without it parting. If a SLC is needed it might be more economical to use a heavier weight tubing.

Table 1 covers tubing and liners. For a corrosive situation where a CRA is required for the tubing it may not be necessary for a CRA liner to be installed. The corrosion conditions for the liner might differ from the tubing. It may also be acceptable in corrosive conditions to allow the liner to corrode, if liner failure does not affect the well integrity or production rate.

For materials for water injection tubing see (3.4.1.6).

Table 1 Downhole production tubing, liners and casing

Production	Conditions				Material ⁽¹²⁾
	SLC	Temp.	Sour Regions ¹ H ₂ S	NaCl	
	(mm)	°C	(mbar)	(g/L)	
Oil wetting of walls (Non-corrosive service)	<<3	<200	Regions 0 or 1	Any	CS ⁽¹¹⁾ , ISO 11960, any strength grade.
Water contact with walls (Corrosive or sour service)	<3	<200	Regions 0 or 1	Any	CS ^{(11) (13)} , ISO 11960, any strength grade.
	<3	<200	Regions 2 or 3	Any	CS ^{(11) (13)} , ISO 11960 Q+T grades with hardness ≤ 250 HV 10 (≈ 22HRC) and C90 and T95 grades ²
	<3	80-200	Regions 2 or 3	Any	CS ^{(11) (13)} , ISO 11960 Grade P110 or lower strength ² with Max. 140 ksi yield
	<3	110-200	Regions 2 or 3	Any	CS ^{(11) (13)} , ISO 11960, Grade Q-125 or lower strength.
Water contact with walls (Corrosive sweet service, i.e. "non-sour" service)	N/A	<110	<3.5	<165	13Cr
	N/A	<170	<3.5	<20	13Cr
	N/A	<140	<3.5	<165	S13Cr ³
	N/A	<200	<3.5	<20	S13Cr ³
Water contact with walls (Corrosive sour service)	N/A	As « non-sour »	<5	As « non-sour »	13Cr or S13Cr ^{3,4} (pH >3.5)
	N/A	<200 ^b	<20	<250	22Cr Duplex SS
	N/A	<200 ^b	<100	<250	Super Duplex ⁶
	N/A	<160	<14,000	<250 ⁷	Alloy 825
	N/A	<200	<36,000	<250 ⁷	Alloy 28 ⁸ (pCO ₂ <25 bar)
	N/A	<160	<14,000	<250 ⁷	Alloy 28
	N/A	<200	<80,000	<250 ⁷	Alloy 2550/G3
	N/A	<280	<120,000	<250 ⁷	Alloy C276/C22/G50

Table 1 Downhole production tubing, liners and casing (continued)

Production		Conditions				Material ⁽¹²⁾
Wet/dry oil/condensate		N/A	<110	Any	Any	GRE lined CS ⁽¹⁰⁾
		N/A	<100	Any	Any	GRE ⁹
(1)	SSC regions as defined in Figure 1 of ISO 15156-2. H ₂ S pressures refer to partial pressures of H ₂ S. See also ISO 15156-1.					
(2)	Where necessary, higher strength grades might be qualified for a specific application. Guidance on qualification testing can be found in ISO 15156 Part 1 or EFC 16.					
(3)	Super 13Cr are proprietary materials.					
	(4) Limited to L80 13Cr (AISI 420). Compared to 13Cr, Super 13Cr grades have higher strength (P110), improved resistance to pitting in sweet conditions, but no improved cracking resistance in sour conditions. The temperature and chloride limits are as defined for conditions with < 3.5 mbar H ₂ S. In certain applications specific Super 13Cr alloys can be shown to give better performance than 13Cr. However in general there is no guarantee that one Super 13Cr alloy will perform better than the average 13Cr. If there is an incentive to use Super 13Cr then laboratory qualification testing is required.					
	(5) Duplex stainless steels are most susceptible to SCC between 80 °C and 130 °C. The quoted environmental limits assume that the duplex stainless steel is operating in this temperature regime, or might experience these temperatures at some stage during the service life (e.g. if pulled for a workover).					
(6)	An automatic eddy-current inspection system has been developed to identify the presence of a severe high hardness layer on the outside diameter running axially along the pipe length of duplex stainless steels.					
	(7) The maximum chloride limit on these alloys is somewhat arbitrary. The testing has been carried out at high chloride levels and no appreciable impact of changing chloride concentration has been seen. 250 g/L is used as a value that is unlikely to be exceeded in the field. If higher values are predicted expert advice should be sought.					
	(8) For alloy 28 the partial pressure of carbon dioxide impacts performance. For the conditions quoted here the maximum ppCO ₂ is 25 bar. At lower H ₂ S levels higher CO ₂ levels can be allowed. Alloy 28 is used in the cold worked condition to meet strength requirements. Failures have been seen with higher yield strength materials, and expert advice should be sought when using this alloy.					
(9)	Use of GRE is limited by the combination of pressure and diameter – for increasing diameter the pressure rating decreases (ref. PTS 30.10.02.13. and PTS 31.40.10.19.); pressure here should be the maximum differential pressure across the tubing / lining / casing, i.e. "internal" overpressure (weep or burst failure mode) or "external" overpressure (collapse failure mode, which is not covered in the referenced PTSs). There are limitations on wall thickness: diameter ratio that should be considered. There are also some limitations on the maximum string length in terms of load bearing capacity (ratio of strength to density). These case specific issues should be discussed with the supplier and the Principal's materials and corrosion experts.					
(10)	Use of GRE-lined CS should be limited to products qualified by testing or approved by the Principal. Carbon steel base material shall meet the same requirements for CS in sour service. In deviated wells, wear issues shall be assessed and other approved tubing materials shall be installed at kickoff points as needed.					
(11)	The use of carbon steel shall include a site-specific assessment of SLC and the needed wall allowance during the well life. Downhole corrosion inhibition may be considered for mitigation of required SLC above the deepest injection point.					
(12)	Coated production tubing, both carbon steel and CRA, shall be considered as a mitigator of workover costs (e.g., reduced fishing), enhanced tubing reuse, and improved flow performance. Coated tubing shall not be considered as reducing corrosion time to failure.					
(13)	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 ksi) maximum yield strength. C-Mn steels are not acceptable.					

Consideration should be given to the compatibility of the alloys chosen for tubing and casing with the annulus fluids to be used. Corrosion testing might be required to verify the compatibility of the fluids and metals.

3.2.3 Casing

General annulus corrosion shall be controlled by the use of pH adjustment and oxygen scavengers and/or biocides in the annulus fluids. Grade selection shall be based on the carbon steel entries of Table 1 assuming short-term exposure to produced fluids.

Where the casing extends below the packer (and so comes into contact with the production fluids), the corrosion conditions will differ from the upper section of casing. It might be

acceptable in corrosive conditions to allow the casing below the packer to corrode, if this does not affect the well integrity or production rate; otherwise a CRA suitable for this service should be selected from Table 1.

3.2.4 Xmas trees

General guidelines on suitable materials for Xmas trees are given in Table 2. The use of carbon steel trees clad throughout with Alloy 625 is becoming more widespread to maximise interchangeability of trees.

The standard recommended materials of construction of subsea X-mas tree flowloops are 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 defined in Table 2. Sealing surfaces shall be overlaid with Alloy 625 where there is a potential for crevice corrosion, see (2.2.2). Only qualified suppliers of AISI 410 shall be considered; welding and selection of fittings and flanges for AISI 410 requires special attention.

Table 2 Xmas trees ⁽¹⁾

Conditions				Material
Temp °C	pH ₂ S (mbar)	NaCl (g/L)	Other	
any	< 3.5	< 200	SLC < 3	Carbon steel with Alloy 625 trims
< 140	< 3.5	< 165		Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
< 200	< 3.5	< 20		Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
As non-sour	< 5	As non-sour	pH > 3.5	Martensitic stainless steel (F6NM/CA6NM) with Alloy 625 trims.
< 200 ⁽²⁾	< 10	< 250		22Cr Duplex
< 200 ⁽²⁾	< 20	< 250		25Cr Super Duplex
< 200 ⁽²⁾	< 80	< 50		25Cr Super Duplex
< 200	<5,000	< 200		Alloy 718 ⁽³⁾ or Alloy 925 with Alloy 625 sealing faces ⁽⁴⁾
< 240	<30,000	< 250		Alloy 625 type, e.g., Alloy 625+, Alloy 625PH or Carbon steel clad throughout with Alloy 625 ⁽⁴⁾
(1) The "Material Requirements" guidance for wellhead and Xmas tree equipment provided by ISO 10423 in Table 3 should be used with care, because the classes are very broad. It should also be noted that ISO 10423 Table 3 defines "trim" as "Pressure-controlling parts, stems and mandrel hangers". The use of Alloy 625 for trims arises from the need to prevent even minor corrosion of valve seals and sealing faces that could impair their function. (2) Duplex stainless steels are most susceptible to SCC between 80 °C and 110 °C. Although the temperature quoted is 200 °C, the pH₂S and NaCl limits are based on the most susceptible temperatures; this assumes that the duplex stainless might experience these temperatures at some stage during the service life. (3) For Alloy 718 a maximum of 0.2 % proof stress should be specified. In the fabrication process the annealing operation is critical to ensure that the delta phase is taken back into solution. The details of the heat treatment shall be checked by the Principal and the heat treatment process witnessed. Where there is any doubt about the heat treatment the microstructure should be checked (replication techniques have been successfully used to quantify the amounts of delta phase). Where delta phase is detected expert opinion should be sought on defining acceptable levels. For sour exposure above 5,000 mbar pH₂S, laboratory evaluation of representative material in field specific conditions should be carried out (4) For Alloy 625 the partial pressure of carbon dioxide has an impact on performance. For the conditions quoted here the maximum pCO₂ is 23 bar. At lower H₂S levels higher CO₂ levels can be allowed. When using this alloy expert advice should be sought.				

3.2.5 Vessels and Piping

This section does not apply to glycol contactor and regeneration system vessels (3.2.9) and utility systems, [including water systems (3.4)].

Vessel material selection depends upon an analysis of the corrosivity of the internal and external environment, material properties and economic factors. Experience shows that corrosion inhibitors are generally not effective in vessels; where carbon steel plus inhibition is used in upstream piping, the vessel should have suitable internal corrosion protection, such as CRA cladding or organic coating. CRA cladding and lining may be full or partial

depending upon the assessed corrosivity. Suitable materials for vessels are given in Table 3, depending upon the cumulative corrosion loss estimated for the SLC and other internal environment constraints. Materials for vessels shall be in accordance with requirements of either PTS31.22.10.32., PTS 31.22.11.32. or PTS 31.22.20.31., depending on whether the vessel is being designed to PD 5500, EN 13445 or ASME VIII. In the Table 3, 1420 and 1440 are sour service grade carbon steel piping specifications, see PTS 31.38.01.15. These materials are not intended for low temperature service. Hardness requirements and sulphur limitations are covered in PTS 39.01.10.11. CRA cladding will reduce the amount of hydrogen produced due to corrosion (possibly to zero - no corrosion process on the CRA) and diffusion of hydrogen through the CRA will be several orders of magnitude slower than through carbon steel. So the risk of SSC and HIC on the carbon steel behind the cladding is considered negligible. For the carbon steel in a clad vessel the recommendations are:

- Follow the hardness requirements and S limitation in PTS39.01.10.11. Section 2.4.4.4 Table 4. This gives good quality steel without excessive cost.
- No requirement for HIC testing of the steel.
- Be very certain in the design and fabrication that the cladding is continuous over the whole vessel surface.
- This approach is NOT suitable for partially clad vessels.

CRA clad vessels do not require a corrosion allowance to be applied to the carbon steel underneath the cladding.

Internal cracking of stainless steels is a risk if the chloride levels in Table 3 are exceeded. This can occur through chloride conditions higher than expected in the fluids entering the system (e.g. formation water is higher in chlorides than expected or there are high chlorides occurring from acid returns or returns of completion fluids). It can also occur through concentration of the chlorides within the piping system. Austenitic stainless steels can also suffer from polythionic acid stress corrosion cracking (PASCC), which can occur when these materials are in sour service and are exposed to air. More details are given in (2.1.2). The risk of these events occurring should be assessed when selecting stainless steel materials.

Galvanic anodes may be an option if (a) vessel waters have a pH above 5.0 and temperature below 50 °C, (b) a minimum of 3 mm corrosion allowance is present, and (c) sufficient corrosion allowance is available for vapour phase corrosion.

Table 3 Vessels and piping

Internal Environmental conditions				Materials selection for piping ¹⁰	Piping class ⁽¹⁾	Vessel material
SLC (mm)	Temp (°C)	pH ₂ S (mbar)	NaCl (g/L)			
< 1	< 200	< 3.5	Any	CS with 1 mm c.a.	1410, 1450, or 1470	As for piping
< 3	< 200	< 3.5	Any	CS with 3 mm c.a.	1430 or 1490	As for piping
3 to 6	< 80	< 3.5	Any	CS with 3 mm c.a. ⁽²⁾ . If only limited life is required ⁽³⁾	1430 or 1490	As for piping + glass flake lining ⁽⁴⁾ . Temperature limit is for the glass flake lining.
< 1	< 200	< 100	Any	SSC and HIC-resistant steel with 1 mm c.a.	1420 or 1460	As for piping
< 3	< 200	< 100	Any	SSC and HIC-resistant steel with 3 mm c.a.	1440	As for piping
3 to 6	< 80	< 100	Any	SSC and HIC-resistant steel with 3 mm c.a. ⁽²⁾ . If only limited life is required ⁽³⁾	1440	As for piping + glass flake lining ⁽⁴⁾ . Temperature limit is for the glass flake lining.
≥ 6	<120	< 8	100	AISI 316L	3430	CS clad with AISI 316L or solid AISI 316L ⁽⁵⁾ or 22Cr Duplex ⁵
≥ 6	< 200	< 10	< 250	22Cr Duplex	3832	CS clad with AISI 904L or solid 22Cr Duplex ⁽⁵⁾ . (6)
≥ 6	< 60	< 15	100	AISI 316L	3430	CS clad with AISI 316L or solid AISI 316L ⁽⁵⁾ or 22Cr Duplex ⁽⁵⁾ . (6)
≥ 6	< 200	< 20	< 250	Super Duplex		CS clad with AISI 904L or solid 22Cr Duplex ⁽⁵⁾ . (6)