

THE ENGINEERING EQUIPMENT AND MATERIALS USERS ASSOCIATION

GUIDELINES FOR MATERIALS SELECTION AND CORROSION CONTROL FOR SUBSEA OIL AND GAS PRODUCTION EQUIPMENT

(2nd EDITION)

PUBLICATION N° 194 : 2004

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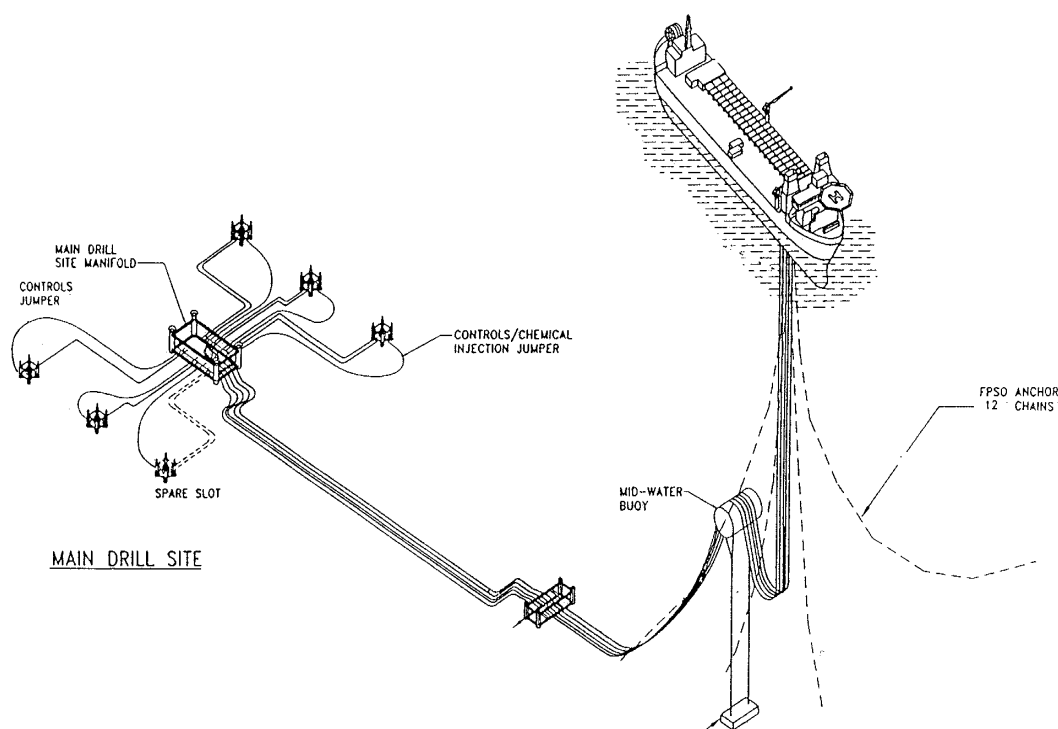
GUIDELINES FOR MATERIALS SELECTION AND CORROSION CONTROL FOR SUBSEA OIL AND GAS PRODUCTION EQUIPMENT

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FOREWORD

Although subsea well completions, manifolds, flowlines and associated equipment have been used for around 25 years, there is a continuing need for increased, up-to-date guidance and awareness of materials selection and performance, the reasons for which are expanded upon in the Introduction.

Accordingly, this guidance document was developed by EEMUA's Materials Technology Committee (MTC), and first published in 1999. Since then, significant further developments in subsea materials technology and operational experience have occurred. These have been captured in this second edition which has been completely updated by a specialist work group of MTC, comprising metallurgists and corrosion engineers with particular expertise in the subsea environment drawn from leading oil and offshore engineering companies.

Extensive reference is made in the text to various industry, national and international codes and standards. As this Publication is a guide and not a specification, such references are for guidance only. A comprehensive list of references is given in Appendix I.

Phrases such as 'at present' are used in the text to indicate conditions obtaining at the time of writing, i.e. mid-2004.

Abbreviations used in this Publication are listed in Appendix VIII.

1

1 INTRODUCTION

This EEMUA publication provides equipment designers, suppliers, fabricators, installers and end users with an overview of the current knowledge (2004) of the principles and practices of materials selection and corrosion control for subsea oil and gas production equipment. Guidance on the application of such knowledge is considered necessary because:

- some expensive subsea materials-related failures have occurred over recent years
- the complexity of subsea equipment is continually increasing: items such as multiphase pumps, separators and water injection facilities are becoming more commonly specified
- the amount of hydrocarbons recovered from subsea developments is set to continue to increase in the future, hence the reliability of subsea equipment has become increasingly important for the producing companies
- deep water developments have become more common, and the performance of materials in such environments is not well understood and documented at present
- reservoir fluids from marginal fields may become increasingly corrosive/erosive
- relatively little detailed guidance is available in existing industry codes, standards etc.
- the integrity of subsea equipment is paramount for protection of the environment.

At the time of this revision, some areas of subsea materials technology are continuing to evolve, hence the associated information in this EEMUA publication should be supplemented or qualified by the latest knowledge and experience. In order to assist with further updating of this publication to ensure its continued relevance, EEMUA would welcome feedback from users of their experiences regarding materials performance in the subsea environment.

2 SCOPE

2.1 TECHNICAL GUIDANCE

This document sets out the principles and practices of materials selection and corrosion control, and provides information on lessons learned in the industry. Key aspects of welding and fabrication are also discussed. However it should not be seen as an alternative to the involvement of suitably qualified metallurgical and corrosion specialists in subsea projects. Indeed, the complexity of some of the issues involved is such that the document cannot always provide definitive recommendations, and the requirement for expert advice on materials issues will remain.

There are many associated topics that could affect materials performance and equipment integrity that are not addressed in any detail in this document, e.g.:

- welding and cladding procedures
- weld defect acceptance criteria
- non-destructive examination requirements
- QA/QC procedures during component manufacture
- verification and validation testing of assembled equipment
- chemical treatment of hydrotest fluids
- methods of deployment of equipment to avoid sea water ingress
- subsea connection procedures to avoid or minimise sea water ingress.

2.2 EXTENT OF APPLICATION

The document relates to equipment fully immersed in sea water installed at or above the seabed for oil and gas production, including water, gas and chemical injection systems and their associated controls—essentially everything from the wellheads downstream to the delivery point to the surface facilities. The equipment is that typically associated with subsea developments, using either tie-backs to fixed platforms, or an arrangement of rigid or flexible risers to floating production units which could be semi-submersibles or monohull vessels.

The emphasis is on the identification and discussion of those materials- and corrosion-related issues which are specific to subsea equipment and which are not usually encountered in offshore platform-based designs utilising dry completions.

Outside the scope are:

- drilling and downhole equipment
- items used only for the deployment, retrieval or maintenance of the permanently installed facilities (though the materials used for such equipment should be subjected to review, based on the principles in this document: at least one serious incident is known to have occurred due to rapid galvanic corrosion of aluminium components in deployment equipment)
- structural items and steel fabrications
- topside equipment.

3 GENERAL PRINCIPLES OF MATERIALS SELECTION AND CORROSION CONTROL

3.1 REFERENCE STANDARDS

The most relevant and useful reference documents which relate **specifically** to subsea materials selection and corrosion control are currently those listed below. Some are quite detailed and give clear materials requirements, but usually without supporting explanations. Others deal with materials rather more superficially.

Most of the relevant international documents have been issued as a suite of ISO standards, which are numbered as ISO 13628-1 to -9, Design and Operation of Subsea Production Systems—Parts 1 to 9. These have in general been developed from the API 17 series of documents, as tabulated below. Where indicated, the latest editions of the API publications are technically identical to their corresponding ISOs—information from 2004 API catalogue.

API	Equivalent ISO
RP 17A: Design & Operation of Subsea Production Systems (co-branded ISO 13628-1)	13628-1: General Requirements & Recommendations
RP 17B: Flexible Pipe (contains full text of ISO 10420)	10420: Flexible Pipe Systems for Subsea & Marine Riser Applications (to be replaced by 13628-11)
RP 17C: TFL (Through Flowline) Systems (co-branded ISO 13628-3)	13628-3: Through Flowline (TFL) Systems
Spec 17D: Subsea Wellhead & Christmas Tree Equipment	13628-4: Subsea Wellhead & Tree Equipment
Spec 17E: Specification for Subsea Umbilicals	13628-5: Subsea Umbilicals
Spec 17F: Specification for Subsea Production Control Systems (co-branded ISO 13628-6)	13628-6: Subsea Production Control Systems
Spec 17G: Design and Operation of Completion/Workover Riser Systems	—
Spec 17J: Unbonded Flexible Pipe	13628-2: Flexible Pipe Systems for Subsea & Marine Applications
Spec 17K: Specification for Bonded Flexible Pipe	—
Spec. 17TR1: Evaluation Standard for Internal Pressure Sheath Polymers for High Temperature Flexible Pipes	—

Note.— Annex A to ISO 13628-1 includes descriptions of the various components of a subsea production system. It is a useful guide for those unfamiliar with such systems.

Other relevant subsea documents include NORSOK Standard M-001 Materials Selection subsec. 5.6 'Subsea production and flowline systems'.

3.2 THE NEED FOR INTEGRITY

Integrity, in the context of subsea equipment, usually means:

- reliable operability with minimal intervention
- no loss of containment of hazardous or toxic fluids.

Failure of subsea pressure boundary equipment by corrosion or cracking will usually result in some environmental impact—possibly serious in the case of hydrocarbons and chemicals. The feasibility of condition monitoring of equipment to prevent such incidents needs to be considered during materials selection. Subsea equipment, by its very nature, is far more difficult and expensive to inspect and maintain than its equivalent topside or onshore. This is particularly the case in deepwater developments where divers cannot operate. Some equipment items, particularly in complex and compact assemblies such as manifolds, can only be properly inspected by retrieval to the surface. Currently available inspection and condition monitoring technologies include the following:

- general visual/ROV inspection
- internal corrosion/erosion monitoring of flowlines and pipelines
- sand detection
- cathodic protection surveys
- intelligent pigging of pipelines
- ultrasonic thickness surveys
- external crack detection
- bolt/stud crack detection
- vibration/movement measurements
- stress/strain monitoring, e.g. of dynamic risers and umbilicals
- leak detection (visual, acoustic, laser)
- functionality testing of remotely actuated and ROV operated valves
- monitoring of status of subsea sensors (temperature, pressure, sand etc.)
- non-metallic materials degradation monitoring, e.g. textile rope coupons
- monitoring flexible piping annulus fluids
- eddy current inspection of flexible pipe armour wires
- electrical resistance integrity tests for control system umbilicals.

Failure of non-pressure boundary equipment that impairs or even prevents operability can be equally expensive to correct, both in terms of the cost of intervention and the value of deferred or lost production. In this context, even small and seemingly minor items can become profoundly important if they fail in service, e.g. set screws mounting a hydraulic control valve onto a panel, or a circlip retaining an umbilical coupler in its mounting.

The overall picture is that increasing water depth and field life favour a trend towards a ‘fit and forget’ philosophy, where increasingly robust materials and designs are employed, and reliance on in-service inspection and monitoring is kept to a minimum.

3.3 EQUIPMENT CRITICALITY

Methodologies for assessing equipment criticality usually combine the probability and consequence of failure, and these have been used for the selection of materials and for defining product reliability requirements in projects. This approach is not recommended for subsea equipment because, as explained above, many items will have high consequences of failure, and meaningful discrimination into different grades of criticality can be difficult to achieve. Also, it would be necessary to consider all feasible ‘failure’ modes—not just those associated with loss of containment, but all those possible causes of loss of functionality or operability.

Subsea equipment design, materials selection, fabrication, testing and installation all require attention to detail of a higher level than that traditionally associated with topside/onshore facilities. Appropriate integrity assurance processes should therefore be applied through all these stages, e.g. independent design verification, qualification of new designs/materials/fabrication methods, procurement QA, materials certification and traceability.

3.4 LIFE CYCLE COSTING

Life cycle costing for materials selection is recommended, though its application is likely to be limited to relatively few equipment items where realistic options exist for both 'high' and 'low' capital expenditure. The most common example is inhibited carbon steel versus corrosion resistant alloy (CRA) for flowlines, where the field life operating costs for the inhibitor injection and the associated corrosion monitoring and pipeline condition assessment can usually be estimated fairly accurately. Strategic replacement of equipment during field life should also be considered.

Guidance on the application of life cycle costing may be found in ISO 15663-1.

3.5 THE PROCESS-SIDE ENVIRONMENT

3.5.1 Introduction

The principles of materials selection for process-side environments are similar to those for surface designs, except that a more conservative approach can often be justified for the reasons stated. Table 1 (opposite page) provides a summary of the compositions, properties and application limits of the most commonly specified subsea CRAs.

3.5.2 H₂S-Containing Environments

3.5.2.1 Relevant Standards

Documents describing options for dealing with H₂S in the produced fluids include:

- ISO 15156/NACE MR0175 (the NACE MR is co-branded)
- NACE Report 1F192
- EFC Publications 16 and 17
- NACE TM0177
- NACE TM0284.

3.5.2.2 Sulphide Stress Cracking (SSC) Resistance of 13% Cr and Duplex/Superduplex Stainless Steels

For carbon or low-alloy steels, the cost impact of using 'sour-resistant' grades is usually minimal, hence they are often specified for environments containing even low H₂S levels, i.e. below the thresholds for SSC as defined in the above documents. For CRAs with only limited 'sour resistance', however (e.g. weldable 13%Cr steels and duplex/superduplex stainless steels), the need to use a different alloy composition for sour service is likely to have a significant cost impact.

TABLE 1 CRAs COMMONLY USED IN SUBSEA EQUIPMENT

Generic Type	Common Name	UNS	Typical Composition				Typical Properties, MPa ¹		Typical Min Design Temp	PREN ² (min)
			Cr	Ni	Mo	Others	Min YS	Min TS	°C	
Austenitic Stainless Steels	316L SS	S31603	18	12	2.5		205	515	-196	22.6
	Nitronic 50	S20910	20.5	12.5	2.25	Mn, Nb, N	380	690	-196	28.6
	Nitronic 60	S21800	17	8.5	0	Mn, Si, N	345	655	-196	17.3
Super-austenitic Stainless Steels	254SMO	S31254	20	18	6	N	300	650	-196	42.2
	904L	N08904	21	25	4.5	Cu	220	490	-196	32.2
	Alloy (Sanicro) 28	N08028	27	31	3.5	Cu	215	550	-196	35.9
Precipitation-Hardened Aust. SS	Grade 660	S66286	15	25	1.25	Al, Ti, V, B	585	895	-29	16.8
Duplex Stainless Steels	Nitronic 19D	S32001	19.7	1.6	0.06	Mn, N, Cu	450	620	-50	22
	22% Cr Duplex	S31803	22	5.5	3	N	450	620	-50	30.5 ⁶
	25%Cr Superduplex	S32550	25	5.5	3	N	600	760	-50	32.2 ⁵
	25%Cr Superduplex	S32750	25	7	3.5	N	550	800	-46	37.7 ⁵
	25%Cr Superduplex	S32760	25	7	3.5	N, Cu, W	550	750	-46	37.1 ⁵
Martensitic Stainless Steels	410 SS	S41000	12.5	0	0		380	585	-10	11.5
	F6NM	S42400	13	4	0.5		620	790	-46	13
	Super-13%Cr (weldable)	Appx IV	11–13	2.5– 6	1– 3		500	600	(Note ³)	
Nickel Base Alloys	Alloy (Incoloy) 825	N08825	21	42	3	Cu, Ti	175	515	-196	27.8
	Alloy (Incoloy) 925	N09925	21	44	3	Cu, Ti, Al	810	1210	-196	27.8
	Alloy (Inconel) 625	N06625	22	60	9	Fe, Nb	415	825	-196	46.4
	Alloy (Inconel) 718	N07718	19	53	3	Fe, Al, Ti, Nb	1030	1275	-196	26.2
	Alloy (Inconel) X-750	N07750	16	75	0	Fe, Al, Ti, Nb	895	1275	-196	14
	Alloy (Inconel) 725	N07725	21	57	8	Fe, Al, Ti, Nb	895	1200	-196	42.1
	Alloy (Hastelloy) C-22	N06022	21	55	13.5	Fe, Co, W	310	690	-196	65.5
	Alloy (Hastelloy) C-276	N10276	16	55	16	Co, Fe, W, V	280	690	-196	64
	Alloy (Hastelloy) C-4	N06455	16	63	16	Co, Fe, Ti	275	690	-196	60.2
	Alloy (Monel) 400	N04400	0	66		Cu	195	480	-196	n/a
Cobalt Base Alloys	Elgiloy	R30003	20	16	7	Co	1510	2500	-196	n/a
	MP35N	R30035	20	35	10	Co	380–1950	9002000	-196	n/a
Copper Base Alloys	Ni-Al-Bronze	C95800		4.5		Cu, Al, Fe	300	650	-196	n/a
	High Strength Cupronickel		0.4	20		Al, Fe, Nb, Mn	700	870	-196	n/a
Titanium Alloys	Grade 5 Ti-6Al-4V	R56400					830	895	-60 ⁴	n/a
	Grade 12 Ti-0.3Mo-0.8Ni	R53400					345	483	(Note ⁴)	n/a
	Grade 19, Beta-C	R58640					896–1170	965–1240	-60 ⁴	n/a
	Grade 23, Ti-6Al-4V ELI	R56407					758	827	(Note ⁴)	n/a
	Grade 29, Ti-6Al-4V-0.1Ru	R56404					758	827	(Note ⁴)	n/a

(Footnotes on next page)

TABLE 1 FOOTNOTES

- ¹ Dependent on heat treatment condition.
- ² $PREN = \%Cr + 3.3\%Mo + 16\%N$ (Several other equations exist).
- ³ Typically from -20°C to -46°C , dependent on grade.
- ⁴ From ANSI–ASME Codes. Good low temperature fracture toughness: dictated by design code.
- ⁵ Superduplex stainless steels are commonly specified to have a minimum PREN of 40.
- ⁶ 22% Cr duplex stainless steels are commonly specified to have a minimum PREN of 35.

‘Sour service’ limits for the weldable 13%Cr and duplex/superduplex stainless steels are somewhat complex. Such materials would probably fail sour service testing in the ‘standard’ conditions used for carbon/low alloy steels (as defined in NACE TM0177 and associated documents). The susceptibility to SSC is a function of the temperature, H_2S level, pH and chloride content of the transported water.

H_2S limits for some grades of 13%Cr and duplex/superduplex stainless steels in specific process conditions are given in ISO 15156 Part 3, NACE MR0175, NACE Report 1F192 and NORSOK Std M-001. Manufacturers of such grades might also recommend sour service limits, and many users have their own guidelines. Typical limits currently considered by some users to be acceptable for the avoidance of SSC are given in Appendix II.

The effects of operations such as welding and plastic straining (e.g. during pipe reeling) on SSC resistance need to be considered.

In cases of doubt, particularly for those materials with uncertain SSC resistance, ‘sour service’ materials testing of parent material and representative welds under the actual or predicted environmental conditions (or under a ‘worst case’ estimate of conditions) at a load close to yield should be made. A conservative approach to materials selection is recommended where conditions are considered marginal between different classes or grades of steels/alloys. Alternatives such as carbon steel clad or lined with a high alloy CRA (e.g. Alloy 625) should be considered.

3.5.2.3 HIC-Resistance of Carbon and Low Alloy Steels

Recommendations to deal with hydrogen-induced cracking (HIC), stress oriented HIC (SOHIC) and stepwise cracking (SWC) are made in ISO 15156 Part 2 and EFC Publication 16, and need to be considered for **any** level of H_2S in the produced fluids. Test methods for assessing the susceptibility of materials are NACE Std TM0284 (HIC) and NACE TM0103 (SOHIC).

The probability of HIC can be minimised by steel chemistry control and by avoiding plate steels for fabricated items, e.g. valve bodies, longitudinally welded piping.

3.5.3 CO_2 -Containing Environments

Documents providing guidance for the use of carbon and low alloy steels in wet CO_2 environments include EFC Publication 23 and NORSOK Std M-506. Some users have generated their own predictive models for CO_2 corrosion that differ mainly in terms of the effects of protective scaling at elevated temperature, stream velocity, and algorithms for pH prediction. Effects of organic acids should be taken into account in corrosion prediction modelling and in any testing for corrosion inhibitor selection.

The main value of these documents and models will be for the prediction of CO₂ corrosion rates, and thereby the assessment of the viability of using carbon or low alloy steels for subsea equipment. The more conservative approach to subsea materials selection often results in higher alloy materials being selected.

The corrosion performance of the higher alloys in CO₂-containing environments should be considered in terms of both general corrosion or localised corrosion, especially in high temperatures and/or high salinity waters. Intergranular corrosion associated with sensitisation of the weld HAZ of 'lean' grades of weldable 13Cr alloys has also been observed (see Appendix IV).

3.5.4 Chloride Ion Environments

300-series austenitic stainless steels in the as-welded or cold worked condition are well known to be highly susceptible to chloride stress corrosion cracking (SCC) at metal temperatures above about 50°C. Due to their low strength properties, these alloys find relatively little application for subsea pressure containment equipment other than for hydraulic control/chemical injection tubing (see 11.2.1 below).

Although duplex stainless steels have far superior resistance to chloride SCC, very high concentrations of chloride ions in combination with relatively high temperatures (> 100°C) can lead to failures. Several such incidents in topsides process equipment have occurred, either due to internal or external induced cracking. The conditions under which cracking can occur are not well understood: a summary of the failures and current knowledge of this phenomenon can be found at the UK Health and Safety Executive website: <http://www.hse.gov.uk/research/rrpdf/rr129.pdf>.

The relevance of these failures to subsea duplex stainless steel equipment needs to be considered, but in many cases will not be significant. The internal failures were associated with water flashing downstream of control valves in the gas–condensate systems of HP/HT plant, allowing internal deposition of very corrosive high chloride solids. The process conditions that led to these failures are unlikely to be experienced subsea but should nevertheless be checked in HP/HT developments where duplex stainless steel is proposed for flowlines or manifold piping.

Where doubts about the suitability of duplex stainless steel in HP/HT environments exist, consideration should be given to more chloride SCC-resistant materials such as Alloy 825 or carbon steel internally clad with Alloy 625.

3.5.5 Erosion

3.5.5.1 General

Erosion can be defined as the wastage that occurs by mechanical removal of material from surfaces due to the impact of liquid droplets and/or solid particles. It will need to be considered for all production scenarios, but especially for equipment handling high velocity multiphase streams or when solids production is expected.

Guidance is available in a number of documents, including ISO 13703, API RP 14E and DNV RP-O501. Predictive models to evaluate erosion rates by solids (e.g. sand) have been developed in a number of joint-venture projects, including those run by the University of Tulsa's 'Erosion-Corrosion Research Center' and by AEA Technology. A predictive model has also been developed by DNV (RP-O501), whilst the UK Health and Safety Executive has published guidance on the avoidance of erosion of piping elbows on its website (obtainable from www.hse.gov.uk, type 'Research Report 115' in the search box).

3.5.5.2 Types of Erosion Damage

Erosion damage can be essentially categorised as four main types:

(1) *Pure erosion by liquid droplet or gas bubble impact in a non-corrosive fluid.* In a multiphase flow regime, droplet impact is possible in annular mist flow (the corollary to this would be bubble impact in bubbly flow, although this is significantly less damaging) and can result in the mechanical removal of material (i.e. erosion). In practice, droplet erosion is generally only a problem in multiphase systems with high mixture velocities. For gas–condensate systems DNV RP-O501 recommends a maximum velocity of 70 to 80 m/s. Another approach to derive maximum allowable velocities is that of API RP 14E, using company-specific ‘C’ constants derived by testing and/or experience.

(2) *Pure erosion by solid particle impact in a non-corrosive fluid.* This mechanism could apply to very low corrosivity or dry gas, gas–condensate or oil systems where corrosion is not a problem. Production rate is highly relevant here because, typically, doubling the production rate will result in an order-of-magnitude increase in erosion rate. Sand content and erosion rate, however, are generally in direct proportion, except for very high sand contents when energy losses occur due to inter-particle collision.

(3) *Erosion–corrosion by a corrosive fluid in the absence of solids.* Most oil and/or gas production systems will exhibit some corrosivity. In the absence of solids, enhanced erosion–corrosion wastage can occur due to the removal of protective corrosion product layers or corrosion inhibitor films by the fluid flow, with consequent corrosion of the newly exposed surface.

(4) *Erosion–corrosion by a corrosive fluid containing solids.* In solids-containing fluids, there can be synergy between the erosion and corrosion rates, e.g. due to the removal of protective corrosion scales or inhibitor films, such that the resultant damage can be significantly enhanced. However, as a rule of thumb, if the expected erosion rate is an order of magnitude less than the expected corrosion rate, or vice versa, then synergistic effects between them are likely to be minor.

3.5.5.3 Likely Locations and Nature of Erosion

Guidelines for identifying the likelihood, locations and nature of erosion are set out below.

- In the absence of solids, erosion is unlikely to be a problem unless flow rates are very high. Wastage is most likely to be corrosion dominated.
- Solids erosion is by far the most aggressive damage mechanism. Severe erosion problems are therefore most likely to be associated with entrained solids.
- Erosion is most likely to occur at changes in flow direction, e.g. bends, tees, at or downstream of constrictions or valves (especially chokes).
- Eroded surfaces will generally be shiny and relatively free from deposits. They also appear relatively smooth, due to the polishing effect of the erosion damage.
- Where erosion pits are formed, they exhibit a characteristic sharp-edged appearance, either as a tear-drop shape (with the narrow end upstream) or as a horseshoe shape.

3.5.5.4 Alleviating Damage by Erosion

Possible methods for alleviating the effects of damage by erosion include:

- Designing out erosion by removing the solids (downhole sand screens, gravel packs, in-line sand removal equipment etc.), reducing the flow velocity (e.g. by increasing pipe diameter, using 'dual' lines), giving close attention to manifold piping design, eliminating sharp bends, using target tees (NB: not universally effective and not normally beneficial for liquid systems, only really useful for gas systems and the like) and erosion-resistant valve designs. API RP 14E, ISO 13703 and DNV RP-O501 give further guidance on some of these aspects.
- Using erosion-resistant materials for solid-particle containing conditions. Carbon steels, stainless steels and nickel-base CRAs are often not suitable for duties where erosion by solid particles is a problem. Suitable materials are often very hard e.g. proprietary cobalt-base alloys, tungsten carbide or ceramics, but are not a universal panacea: even those materials will experience erosion under severe conditions. Alternatively, very soft elastomeric coatings or liners are possible options, but it needs to be demonstrated that they are resistant to the production fluids and operating temperatures. As yet, there is no extensive experience with non-metallic materials in such service.
- For nominally solids-free production (less than one pound of solids per thousand barrels of liquid (1 pptb) for liquid flow, or 0.1 lb of solids per MMscf (millions of standard cubic feet) of gas for gaseous flow, consider the use of erosion–corrosion resistant materials. The higher alloy CRAs are generally more erosion–corrosion resistant than carbon steel or 13Cr steel as they do not suffer from the same levels of synergistic erosion–corrosion. However, care should be taken when selecting CRAs for erosion–corrosion resistance, accelerated corrosion rates could occur for CRAs if the passive film is removed by solids erosion and the environment does not enable the passive layer to rapidly reform.

3.5.5.5 Use of 'C-Factors'

Recently there has been a move away from the use of the API RP 14E equation together with the material- or application-specific C-factors, due to the fact that this methodology does not account for many of the major factors that affect erosion, such as fluid viscosity, solid particle size and concentration, flow regime, etc. In addition, the method can prove either overly conservative (for liquid flow) or non-conservative (for gas flow) if C-factors are selected to try to cover the full range of mixture densities. However, the API RP 14E approach can provide a useful 'order of magnitude' evaluation tool for totally solids-free or nominally solids-free conditions as long as the severe limitations in its use are realised and appropriate C-factors are generated for the materials/fluids/conditions under consideration.

The 'C-factor' constants recorded in API RP 14E are generally considered to be somewhat conservative, both for carbon steel and for CRAs, and higher values are utilised by many designers/users. Typical values which have been used for nominally solids-free or totally solids-free conditions, derived from both laboratory testing and field experience, are:

- carbon or low-alloy steel— 135 (gas or multiphase) or 250 (liquid only)
- 13Cr stainless steels— 300 (gas, multiphase or liquid)
- CRAs (i.e. super-austenitic stainless steels, duplex stainless steels, nickel alloys)— 350 (gas or multiphase) or 450 (liquid only).

For absolutely solids free, single-phase gas conditions no erosional velocity limit is imposed.

3.5.6 Chemical Treatment and Deployment

Chemical treatments are frequently adopted for flow assurance and/or the control of corrosion or scaling in subsea producing systems, e.g.:

- corrosion inhibition/pH modifiers
- scale inhibition
- hydrate inhibition
- wax control
- asphaltine control
- flow improvers.

Earliest consideration should be given in system design to the range of expected chemical treatments, understanding how the required chemicals will interact with the materials they contact (metals and elastomers) and how they will behave with one another when mixed.

The compatibility between treatment chemicals should be established before their final selection and use, since any potential incompatibility may result in neutralisation of one (or more) of the products' active ingredients, or in precipitation and blockage ('gunking').

If the range of chemicals or their compatibility with each other is not known at the design stage, installation of dedicated injection facilities for each chemical type is advised. The use of shared distribution and injection facilities is not recommended unless mixing and compatibility trials on the designated chemicals demonstrate no adverse interaction or precipitation. (See also Section 12 for recommendations for transport of chemicals by umbilicals).

The rheology of the chemicals at ambient temperature and seabed pressure and temperature needs to be understood when designing the pumping, delivery and distribution systems. Required flow rates, including chemical suppliers' minimum advised rates, need to be considered when sizing umbilical cores and specifying pumps. Distribution, injection facilities and flow measurement devices need to cater for any rheological changes between the point of supply and injection.

Suitable redundancy in the supply system may be necessary in order to achieve required chemical availability.

3.5.7 Mercury

Mercury and associated mercury compounds can be detrimental to certain materials. Mercury can occur naturally as a contaminant in well production fluids. The likelihood of its presence should be recognised at the earliest possible stage of design to avoid potentially susceptible materials being specified.

It is generally accepted that mercury needs to be present in the liquid form for damage to occur. Attack can be by amalgamation or by liquid metal embrittlement (LME).

Alloys 400 and K500 fail by LME as a result of mercury adsorption onto their surface. Type 304 and 304L austenitic stainless steels and Alloy 600 have also been shown to be susceptible to LME when subjected to high loads and plastic strain, whilst austenitic stainless steel types 321, 316 and 316L appear to be unaffected in the same way.

It is good practice to avoid the use of copper- and aluminium-base alloys for equipment in mercury-bearing streams.

Whilst unalloyed titanium is considered immune to damage by mercury, it is known that aluminium and copper alloys are affected. Caution should therefore be exercised if titanium alloys containing aluminium and/or copper are proposed for duty in systems that may contain mercury. Testing of these alloys to establish immunity or susceptibility is advised.

3.5.8 Preferential Weld Corrosion

Preferential weld corrosion (PWC) is the dissolution of metal associated with welds. It is a selective form of attack that corrodes either the weld metal and/or heat affected weld zones rather than adjacent parent material. PWC rates of attack in carbon steel can be high: up to 12 mm/yr have been observed in the laboratory and in the field. Since it is a selective form of attack, PWC should not be mitigated by additional design corrosion allowances, particularly for piping and flowlines.

PWC is a particular concern with carbon and low alloy steels used for transporting produced hydrocarbons with entrained water and CO₂, that have been welded with consumables depositing around 1% Ni weld metal. Preferential corrosion of welds containing increased levels of Si, or alloyed with Cr or Mo, can also be expected, although the effect may be less pronounced. Service experience indicates that gas and gas–condensate production systems are more prone to PWC damage than oil systems, and also that Ni-containing weld metal is beneficial for water injection lines.

Guidelines have been developed to reduce the risk of PWC in carbon and low alloy steels, including the selection and deployment of inhibitors. These guidelines will be included in EFC Publication 39 (due to be published in 2004).

3.5.9 Other Considerations

Key additional considerations for materials selection will include:

- internal corrosion at locations of low flow where deposits might form and where corrosion inhibitors and biocides are unlikely to be effective
- internal corrosion due to water drop out at low points
- localised pitting or general corrosion in CRAs at elevated temperatures (especially for 13% Cr and duplex/superduplex stainless steels)
- corrosivity of internal fluids encountered during installation and operational transients (e.g. workovers), including chemical treatments and sea water entry
- the effect of gas lift operations on corrosion
- specification and reliability of facilities for the treatment of reservoir injection fluids e.g. gas dehydration, water treatment, or for other applications e.g. flowline bundle heating
- materials availability, ease of fabrication and track record in the intended application.

3.6 THE SEAWATER-SIDE ENVIRONMENT

Most metallic materials for subsea use require a combination of protective coatings and cathodic protection (CP) to avoid general or localised seawater corrosion, and, in some cases, chloride ion SCC. Materials that can be considered, for design purposes, to be inherently resistant to corrosion in seawater (although even this resistance is only retained up to certain temperature limits) are Alloy 625 and other nickel-base alloys of equal or higher pitting resistance equivalent number (PREN), or titanium.

The maximum iron content at the finished surface of Alloy 625 weld overlays should not exceed 10% for resistance to crevice corrosion.

For optimum corrosion resistance, all austenitic and duplex stainless steels should be used in the solution treated and water quenched condition with microstructures free from undesirable precipitates (e.g. carbides, sigma phase), taking account of the effects of welding or other fabrication procedures. Low carbon austenitic stainless steels should be used to minimise the risk of sensitisation. Free-machining grades should be avoided due to their relatively poor corrosion resistance, even for small items machined from bar stock.

External chloride SCC of duplex stainless steels due to the concentration of chlorides on unprotected high temperature surfaces is generally unlikely to be a problem on painted or insulated subsea components additionally protected by CP. Nevertheless a theoretical risk will exist for HP/HT installations, e.g. at crevices, and so a detailed risk assessment should be made where duplex stainless steels are proposed for such developments.

The corrosivity of the sea water and/or mud at the seabed will depend on factors such as oxygen content, bacterial activity, temperature, currents and salinity. These factors will normally only affect the design of the CP system and the selection of protective coatings, and not materials selection as such.

Materials for raw seawater injection schemes need to be designed in seawater resistant materials and/or using carbon steel with robust internal protective coatings or linings. External CP is not effective in controlling internal corrosion.

Avoidance of external hydrogen embrittlement of carbon or low alloy steels and CRAs induced by CP systems will represent an important part of materials selection and specification, and is discussed in detail in the equipment-specific sections and appendices of this publication.

For raw seawater handling equipment, superduplex stainless steels (PREN > 40), some super-austenitic stainless steels and some copper-base alloys have good resistance to corrosion for restricted (i.e. lower) operating temperatures. Care is required with chlorine or hypochlorite injection in raw seawater injection schemes as this can greatly increase the water corrosivity, further restricting the operating temperatures for these materials.

Occasionally, it is necessary to specify materials with inherent resistance to marine fouling, e.g. for exposed valve stems that could damage stem seals or packing during operation. Copper-base alloys are particularly suitable, and various high strength versions are available including the precipitation treated cupro-nickels and beryllium–copper alloys.

3.7 HYDROTESTING AND COMMISSIONING ENVIRONMENTS

Care is required in the specification and control of hydrotesting media and any other transient environments in order to avoid internal corrosion and fouling. Many grades of stainless steel used for internal components will not be resistant to localised pitting and crevice corrosion in raw seawater. Chemical treatment of hydrotest seawater is required using corrosion inhibitors, biocides and oxygen scavengers. The use of fresh water is preferred, but is often difficult or impractical. Some assemblies such as manifolds can be deployed after filling with treated fluids, e.g. glycol-based control fluids of the type described in 11.2.1.

In all cases attention should be paid to adequate venting to minimise the volume of trapped air since this will promote corrosion. The overall time of exposure to these 'transient' fluids prior to commissioning should be minimised.

4 CATHODIC PROTECTION

4.1 INTRODUCTION

Subsea installations require corrosion protection, usually by external coatings in conjunction with a sacrificial anode CP system. A well designed and installed CP system will normally protect against all the following forms of external attack:

- general corrosion of carbon and low alloy steels
- crevice corrosion, e.g. at screwed and flanged connections (flange protectors are not necessary and are not recommended)
- galvanic corrosion at the junctions of dissimilar metals
- chloride ion SCC of austenitic stainless steels
- pitting corrosion of stainless steels
- bacterial corrosion.

The protective coating reduces the amount of sacrificial anode material required to protect the structure, and enhances the uniformity of the spread of protection.

4.2 CONVENTIONAL SACRIFICIAL ANODE DESIGNS

4.2.1 Existing Practice

Present day CP designs for structures or pipelines immersed in seawater usually follow either DNV RP-B401 or NACE RP0176. For the North Sea and Norwegian Sea the NORSOK Standard M-503 has also been applied. (In the future, the application of ISO 15589-2 is recommended for the CP design for pipelines).

These guidelines are based upon the premise that effective long term CP is reliant upon the build-up and maintenance of calcareous deposits upon the structure being protected. Specific current density requirements at three distinct stages in the structure's life—initial, mean and final—are identified and used to derive an appropriate CP design. High initial current densities are required to promote the rapid formation of the calcareous deposits and minimise the mean current density requirements thereafter. In the case of sacrificial anode systems, it is the mean current density that determines the overall anode weight. Minimising the mean current density requirement limits the additional weight of the anode system on the structure.

The 'final' current density takes into account the additional current density required to re-polarise the structure if the effectiveness of the established calcareous deposits and fouling layers is reduced during storms. The DNV RP gives guidance on these three current density requirements with respect to climatic region, while the NACE RP assigns values to specific coastal, country or sea locations. Neither document makes specific reference to deepwater, yet the industry consensus is that the guidelines are applicable to water depths down to 300 m.

Subsea equipment is usually constructed from many different materials which are not resistant to seawater corrosion and which depend upon CP for their integrity. While it is not necessary for CRAs to be polarised to the same negative potentials as carbon steel, it is normally impractical to electrically isolate them from the main steel structure. In fact it is necessary to ensure that all metallic components are electrically continuous. Typical practices include the use of continuity straps, fan disc washers beneath bolt heads, the removal of paint from contact surfaces, and welding. Electrical continuity checks are

necessary for practically all components that are not connected directly to the main structure by welding. The maximum recommended resistance is 0.1 ohm. Particular attention should be paid to items which, by their design, are either 'loose' or are required to move, e.g. ROV-operated valve stem extensions.

The phenomenon of hydrogen generation on cathodically protected structures is well understood. The rate of reduction of hydrogen ions to atomic hydrogen at the surface of a metal increases logarithmically with a linear negative change at potentials below -800 mV versus Ag/AgCl/seawater. While there is a tendency for hydrogen atoms to combine to form hydrogen gas, the reaction is slow and the atoms have time to diffuse into the metal. The presence of H₂S, due to microbial activity, further promotes hydrogen charging.

Charging can induce hydrogen embrittlement (HE) in many high strength steels, stainless steels and non-ferrous alloys (e.g. nickel alloys). Factors that usually determine the likelihood of HE and cracking taking place are:

- the material's microstructure and hardness
- applied and residual stresses, and whether these are static or dynamic
- excessively negative potentials.

Cracking has occurred with many different materials including high strength steels (>700 MPa yield strength), Alloy K500 polarised to potentials more negative than -900 mV, and both duplex and superduplex stainless steels polarised to about -1000 mV. While HE of titanium due to galvanic coupling with a less noble metal is a well-known phenomenon, there have been no reports of titanium alloys suffering HE subsea.

4.2.2 Deep Water Sacrificial Anode CP Design

Seawater environments change with depth, geographical location and season in a way that can have a significant effect on current density requirements for CP. Oxygen solubility is usually less than in shallower waters, but remains significant; temperatures are lower, fouling is less, seawater velocity, salinity and pH are variable. In some deepwater locations of the world the oxygen content and velocity of the water at the seabed can be surprisingly high due to descending cold polar currents.

Perhaps most importantly, the solubility of calcium carbonate is higher in deep water. Calcareous deposits do not form as readily, nor are they as persistent as in shallow waters. The analysis of seawater properties for the determination of CP current density requirements has proved to be virtually impossible, and so, to date, these requirements for deep-water structures have been mainly developed by empirical means, using test assemblies deployed at the specific water depths of interest. On some occasions, retrospective data have been collected using CP monitoring systems installed on a deep-water platform or installation.

Measurements have confirmed that initial current densities required for the effective polarisation of bare steel in deeper waters are often 1.5 to 2 times those recommended for shallower waters. The two most influential aspects are the poorer quality of the calcareous deposits and the increased hydrostatic pressure. Poor quality calcareous deposits mean that the metal surface is more accessible, and more hydrogen can be generated. The kinetics of the hydrogen ion reduction reaction itself are not directly affected by changes in pressure, but the subsequent combining of hydrogen atoms to produce hydrogen gas, which competes with the entry of atomic hydrogen into the metal, will be retarded. Opportunities for hydrogen diffusion into the metal would appear to be greater in deep water, though whether this increases the susceptibility of materials to HE per se is not clear. Some users take the view it does not, hence they do not distinguish

between deep water and shallow water in defining maximum limits for material strengths and hardnesses.

Laboratory studies have shown that increases in the corrosion rate of carbon steel with increasing hydrostatic pressure can be ascribed to the effect of pressure upon the kinetics of the oxygen reduction reaction. The kinetics of the iron dissolution reaction is not affected, and thus the electrical potential at which iron is immune from corrosion in seawater is the same regardless of water depth. It follows that the same potential criteria for the protection of carbon steel in shallow waters (-800 mV versus Ag/AgCl/seawater in aerobic conditions, -900 mV in anaerobic conditions) are also applicable in deep water. In the absence of any definitive knowledge regarding the effect of water depth upon the growth of sulphate reducing bacteria (SRB), it would be appear prudent at present to adopt the same approach to the risk of SRB proliferation on the seabed or beneath fouling deposits.

There is a dilemma associated with the use of CRAs connected to carbon steel in adequately protecting the latter from general corrosion without inducing HE in the former. The following are seen as key areas in the quest for the level of equipment reliability which deep-water exploitation demands (see also Appendices III and IV):

- The use of component designs which are simple in relative terms and avoid the need for complex geometries as far as possible in order to ensure uniformity of CP.
- The adoption of low maximum allowable global stresses, well below the specified minimum yield stress, and minimisation of stress concentrations (e.g. due to poor fit-up, doubler plates, sharp changes in section etc.).
- Assurance that materials are supplied with optimum heat treatment and microstructure.
- The more widespread use of durable, highly insulating protective coatings on CRAs and high strength steels to minimise hydrogen entry.
- Guidelines on the design current densities to be used on deep-water structures to avoid the application of unnecessarily high current densities. (Note: in practice, cathode potentials during early operating life will be close to open circuit anode potentials due to the general adoption of high quality coatings. Therefore, reductions in design current density alone may not result in significantly lowered risk of HE damage.)
- Assurance that interaction between sacrificial anode CP systems for subsea equipment and impressed current CP systems for FPSOs or other surface facilities does not result in overprotection, increasing the risk of HE.
- Further investigations into the use of low voltage CP using diodes or alternative anode compositions.

4.3 LOW VOLTAGE CATHODIC PROTECTION

4.3.1 Introduction

The relationship between the quantity of hydrogen ions electrochemically reduced to hydrogen atoms at the metal surface and the electrochemical potential is logarithmic: for a unit change in potential there is a tenfold change in the rate of reduction. Limiting the generation of atomic hydrogen at the metal surface by controlling the applied CP potential represents, arguably, the most effective method of minimising HE risks.

The most negative potentials that can be achieved using 'state of the art' sacrificial anodes are governed by the open circuit potentials of the anodes themselves, typically a value of -1050 mV for zinc and -1100 mV for aluminium–zinc–indium. Potentials more negative than -900 mV versus Ag/AgCl/seawater are sufficient to cause embrittlement and crack propagation where the mechanical properties, applied loading conditions and/or microstructure lead to susceptibility to cracking. At potentials less negative than -800 mV the rate of the hydrogen reduction reaction and likelihood of HE cracking become negligible.

4.3.2 Diode Control

The current output of sacrificial anodes and, correspondingly, the potential of the structure, can be controlled using Schottky diodes that only allow current to pass when the voltage across the diode exceeds a certain limit. In the case of aluminium anodes and a controlled negative potential limit on the structure of -800 mV, this potential limit is 300 mV. Once the potential difference between the anode and the structure falls below this level, the Schottky diode becomes open circuit and current no longer flows between the anodes and the structure until the 300 mV difference is restored. For successful control of the potential of the entire structure at risk from HE, every anode needs to be connected to the structure via a Schottky diode. The structure needs to be electrically isolated from adjacent structures with conventional CP systems, otherwise the CP system on the adjacent structure will override the control being imposed by the diodes. The establishment of permanent electrical isolation is often difficult offshore, particularly on complex subsea facilities, in which case the use of diode controlled CP systems should be avoided.

Nevertheless, there have been several instances of the use of Schottky diode-controlled sacrificial anode CP systems to minimise the risk of HE of high strength steels, such as on simple pipeline systems or isolated steel structures. Reports indicate that in conjunction with protective coatings, dioded anodes have performed much as intended. On one bare structure a reluctance to achieve full polarisation has been reported, indicating that there is still much to be learnt about how these systems perform where high current demands are required.

Diode anode designs should be qualified by testing to demonstrate their reliability under the intended operating conditions, particularly the design hydrostatic pressure for deep water.

4.3.3 Low Voltage Anodes

As an alternative to controlling the potential of conventional sacrificial anodes using diodes, recent work by the French navy has aimed at developing a commercial low voltage anode composition based upon aluminium. Initial studies indicate that an Al–0.1% Ga alloy, with an operating potential of -840 to -880 mV versus Ag/AgCl/seawater, is feasible. The composition of this alloy is patented. The same considerations about the need to isolate the structure from adjacent conventionally protected structures would apply. There is little operating experience with these anodes under conditions likely to be encountered, such as high hydrostatic pressure, burial in marine sediments, or higher operating temperatures, and further research or qualification testing should be considered before selection of this option.

Carbon steel/iron anodes can be used to protect some CRAs, and this method has a history in seawater coolers. Whilst the adoption of such anodes would seem an attractive proposition, the lack of operational experience and field-proven design data (particularly in deep water conditions) would indicate that further research and qualification testing would be required.

4.3.4 Implications of Low Voltage CP

There are three significant implications of using low voltage CP to prevent both corrosion and HE of materials subsea which need to be borne in mind:

- *The formation of calcareous deposits.* Conventional CP designs for offshore structures are based upon the assumption of different current density requirements at different stages of the structure's life, and a high current density is desirable at the beginning to enable calcareous deposits to form rapidly. A major consequence of using potential-limiting or low voltage anodes is that, compared with a conventional sacrificial anode CP system, the actual current flowing to the structure is restricted, and calcareous deposit formation will occur at a slower rate. This has a fundamental impact upon CP design that, although not critical for coated structures, requires a reappraisal of the existing design rules where uncoated structures are concerned.
- *Sulphate reducing bacteria.* It is widely acknowledged that where there is a risk of SRB being active, the normally applied CP criterion in sea water of -800 mV versus Ag/AgCl/seawater for carbon steels needs to be adjusted to -900 mV. Such a move to more negative potentials is clearly in conflict with the need to limit CP potentials to prevent HE. Once again, this issue is likely to be more relevant on a bare structure than on one that is additionally protected from corrosion by a heavy-duty coating.
- *The effect upon crevice corrosion.* It is generally acknowledged that in seawater the spread of CP down crevices, such as those at bolted flanges, is sufficient to prevent crevice corrosion, providing that there is effective CP outside the crevice. The term 'effective CP' may be interpreted as measured potentials of typically -900 mV versus Ag/AgCl/seawater outside the crevice. With potentials limited to about -800 mV outside the crevice, there will be a higher risk of crevice corrosion, particularly where the crevice is formed between dissimilar metals.

4.4 ANODE MATERIAL SPECIFICATIONS

Conventional aluminium–zinc–indium alloy anodes can have widely varying composition, particularly with respect to zinc, indium, iron and silicone contents, whilst still meeting the manufacturer's defined alloy specification. There is evidence that anodes may not perform satisfactorily across the widest conventional compositional range, particularly in deep water applications, or in hot operating conditions such as can occur on buried flow-lines. An optimised compositional range and performance requirements should be specified, based on proven satisfactory performance history under equivalent conditions, or on results of qualification testing under appropriate conditions.

Whilst there is still little documented deepwater data available relating to long term anode performance, there are indications that lower electrochemical capacity values may apply for anodes particularly in deep water, and when operated at low anodic current densities typical for well-coated pipelines or subsea equipment. Conservative design capacity values should be selected in the absence of long-term service or qualification data under similar conditions.

5 WELLHEADS AND CHRISTMAS TREES

5.1 INTRODUCTION

There are many materials that can be used for this type of equipment. However, since this document deals only with subsea applications, this section possibly excludes materials that have been used successfully for surface applications. Although valves and bolting form part of this equipment, they are separately dealt with in Sections 8 and 9 of this document.

Wellhead and Christmas tree equipment can be used for hydrocarbon production, sea water injection (raw and treated), and a variety of chemicals for well treatment and gas lift operations. There may be a need for a change in the duty of a subsea tree during its lifetime, e.g. from production to injection, and this should be carefully considered at the design stage in order to ensure that the materials specified have the required properties and corrosion resistance.

5.2 RELEVANT STANDARDS

Relevant standards are ISO 10423, API Spec 6A, ISO 13628-4 and API Spec 17D.

5.3 MAJOR COMPONENTS IN WELLHEAD EQUIPMENT

The major components in wellhead equipment, excluding bolting, are:

- Christmas tree connector
- Christmas tree body
- wellhead housing
- casing hanger
- tubing hanger
- seal assemblies
- valves and chokes
- flow spools.

5.4 MATERIAL CONSIDERATIONS

The items listed in 5.3 are critical components, and careful consideration should be given to the specification of materials. It is recommended that all process-wetted materials other than bolting meet the requirements of ISO 15156/NACE MR0175.

The API Product Specification Level (PSL) for subsea wellhead and Christmas tree equipment is typically 3, though API Spec 17D permits either PSL 2 or 3. The Temperature Classification is typically 'U', relating to an operating range of -18°C to 121°C . It should be noted that API Spec 17D requires all PSL 3 equipment to be impact tested regardless of temperature rating, the requirement being a minimum average of 20 J in the transverse direction at -18°C .

For subsea applications, PSL 3 with a gas test is recommended.

Wellhead equipment should be corrosion resistant to the production and injection fluids in all internally process-wetted areas since, due to the complex geometry and turbulent flow, corrosion inhibition cannot be relied upon to protect carbon and low alloy steels. It is

also very unlikely that protective scales will form at the high velocities experienced in the trees, especially with chemicals being injected downhole.

Materials in direct contact with production fluids can be either inherently corrosion resistant or weld overlaid with a CRA.

Other material considerations are erosion, particularly if sand is produced, and the relatively large section thickness of many of the subsea components that will affect heat treatments and the attainment of suitable microstructures and mechanical properties. Preference should be given to the use of forged products for all high integrity components.

There are many 'minor' components, e.g. control line connectors, which if not correctly specified can lead to failure or malfunction of the equipment. It is therefore recommended that the materials properties and corrosion resistance of all components be considered.

5.5 MATERIAL OPTIONS

5.5.1 Christmas Tree Body and Connector

Forged trees and connectors have been produced successfully in a number of materials:

- low alloy steel, AISI 4130 and 8630, internally overlaid with a suitable CRA, e.g. Alloy 625
- ASTM A182 F22 (2¼%Cr 1%Mo steel), overlaid with a suitable CRA, e.g. Alloy 625
- AISI 410 (13%Cr stainless steel)
- ASTM A182 F6NM (13%Cr 4%Ni stainless steel)
- duplex stainless steel.

It is unlikely that low alloy steel without weld overlay would be acceptable except in the most benign and short service conditions, or for treated sea water injection. Even in those conditions, seat pockets and seal areas should be overlaid with Alloy 625, and trim should be in a suitable grade of stainless steel.

Although AISI 410 and A182 F6NM may have adequate corrosion resistance for many applications, consideration should be given to achieving the required impact toughness in thick section components, and to weldability. F6NM has higher toughness and superior weldability to type 410 stainless steel. Welds in type 410 stainless steel can have relatively poor toughness, even after PWHT.

Duplex stainless steel is not recommended for subsea Christmas tree bodies due to the danger of tertiary phase precipitation in thick section forgings, with resultant deterioration of corrosion resistance and toughness.

Of the above-listed materials, low alloy steel weld overlaid with a suitable CRA, e.g. Alloy 625, represents the lowest risk option for subsea. The preferred low alloy steel is ASTM A182 F22, since this provides better through thickness hardenability in thick section forgings.

Note: The designer should be aware that the mechanical properties determined for large section forgings on a qualification test coupon in accordance with API Spec 6A might only represent the near surface mechanical properties and not the bulk properties. If bulk

section properties are required for design purposes, they should be measured at an appropriate depth into the forging section on a representative prolongation.

Weld overlay should be in all wetted areas, seat pockets and seal areas, with a minimum of two passes to control substrate dilution and ensure maximum residual iron contents of typically 10%

5.5.2 Wellhead Housing, Casing Hanger and Seal Assemblies

These are of thinner section than the Christmas tree bodies, and can be manufactured in AISI 4130 or 8630. Any process-wetted areas and/or seal areas should be overlaid with a suitable CRA, e.g. Alloy 625.

5.5.3 Casing Hangers

Casing hangers are usually manufactured in AISI 4130, 4140 or 8630, and under normal operating conditions do not come into contact with produced fluids.

5.5.4 Tubing Hangers

Tubing hangers should be manufactured from high strength CRA materials; depending on the service, acceptable materials are:

- AISI 4130, 8630 or ASTM A182 F22 weld overlaid with a suitable CRA, e.g. Alloy 625 in all wetted areas.
Note: the designer should be aware of the tendency for the formation of hard zones in the fusion boundary between low alloy steels and Alloy 625 (refer to 6.6).
- ASTM A182 F6NM
- 22% or 25% chromium duplex stainless steel
- Alloy 718 supplied in accordance with API Spec 6A718

5.5.5 Valves and Chokes

The body and bonnets of valves and chokes are usually manufactured in either:

- AISI 4130 or 8630, with any process-wetted surfaces and seal areas being weld overlaid with a suitable CRA, e.g. Alloy 625
- ASTM A182 F6NM.

Stems are typically in high strength CRA materials such as Alloy 718 hard faced with tungsten carbide. Gates are usually manufactured from ASTM A182 F6NM, AISI 4130 or AISI 8630 material and also hard faced: see Section 8.

5.5.6 Gaskets

Gasket materials in subsea hydrocarbon service may be manufactured in type 316 stainless steel, but Alloys 825 or 625 in the annealed condition are preferred for greater corrosion resistance. Where gaskets are to be used in ring grooves overlaid with Alloy 625, it is recommended that Alloy 625 or 6% molybdenum stainless steel gaskets in the annealed condition be used. For treated sea water injection, a 6% molybdenum stainless steel in the annealed condition is acceptable. For raw seawater injection, careful consideration needs to be given to ensuring adequate crevice and galvanic corrosion resistance of materials at the expected operating temperature.

5.5.7 Hydraulic Tubing

Solution annealed AISI 316 or if welded, 316L, stainless steel is commonly used, but for higher temperature applications Alloy 825 is recommended. Alloy 400 is also suitable provided it is not exposed to production fluids containing mercury. See also Section 11.

5.5.8 Flow Spools

Flow spools are usually manufactured from a CRA such as 22% or 25% chromium duplex stainless steel, with induction bends in the solution annealed condition. Higher grade austenitic alloys may be required for sour conditions beyond the safe limits for 25% Cr duplex, e.g. Alloy 825. External painting of the completed spools is recommended in all cases; refer to Section 14.

5.6 EXTERNAL CORROSION PROTECTION

Protective coatings and/or insulation in conjunction with CP, as discussed in Sections 4 and 14, provide external corrosion protection. The paint systems applied to Christmas trees are normally of high quality.

6 MANIFOLD PIPING AND EQUIPMENT

6.1 INTRODUCTION

Subsea manifolds transport, control and sometimes pump the co-mingled production fluids from the wellheads to the processing facilities, and/or the injection water or gas into wellheads. Manifolds typically comprise an assembly of piping, valves, control modules, instrumentation and associated fittings supported within a framework of structural steel. More recent designs may incorporate additional equipment items such as multiphase pumps and associated suction and discharge vessels. Some manifolds also serve as drilling templates, though recent trends have been to use 'cluster' manifolds for tying-in individual satellite wells to flowlines back to a processing facility. Towhead manifolds are used for bundled pipelines installed by towing. The manifold types are shown schematically in Figure 1.

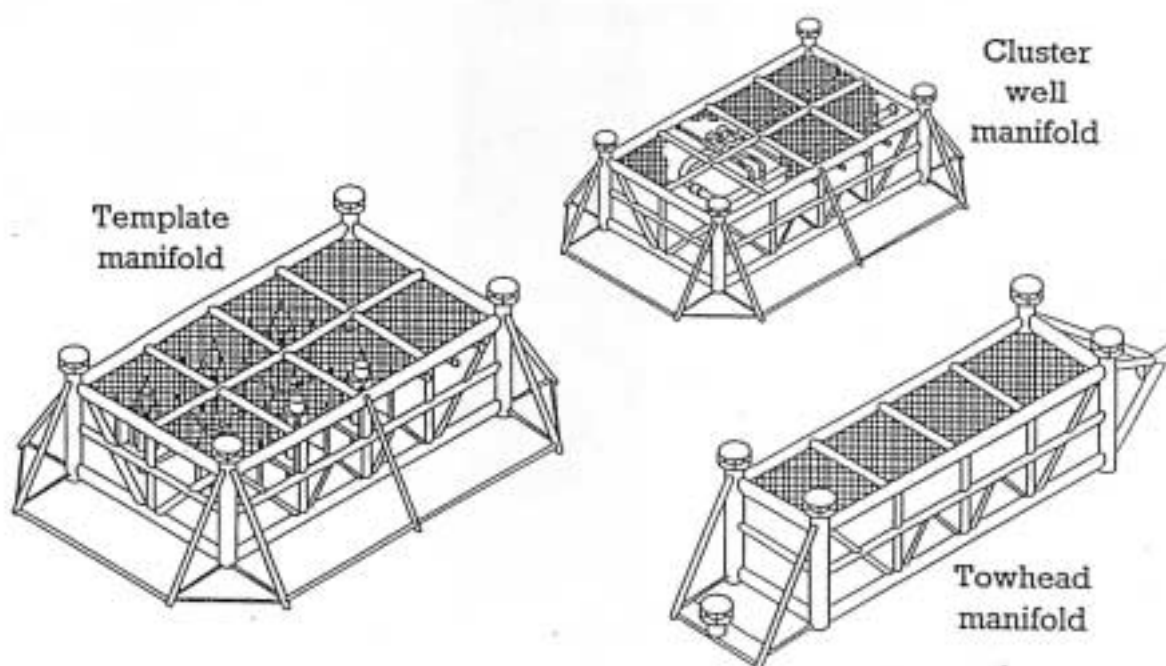


Figure 1 Some Typical Subsea Manifolds

Many different materials may be used for subsea manifold piping and equipment, based on a number of different manufacturing and construction techniques. Acceptable sources of materials include forgings, castings and hot isostatic pressings (HIP) from powder. Each product has benefits, but forgings and HIPped products are usually considered to have the highest integrity and should be the first choice material. Seamless or longitudinally welded pipe may also be used, with branch connections extruded from the main pipe-run by either hot or cold working. Where sour service is applicable to carbon and low alloy steel, a low sulphur, calcium treated and vacuum degassed grade should be used (see 3.5), especially for seam welded piping components.

Connections to the manifold from the wellheads, and from the flowlines to the processing facilities may be either flexible jumpers or rigid pipeline spools, made up by suitable flanged joints or proprietary connectors. Figure 2 (overleaf) illustrates a cluster manifold connected to six satellite wells, with flowlines to the processing facility.

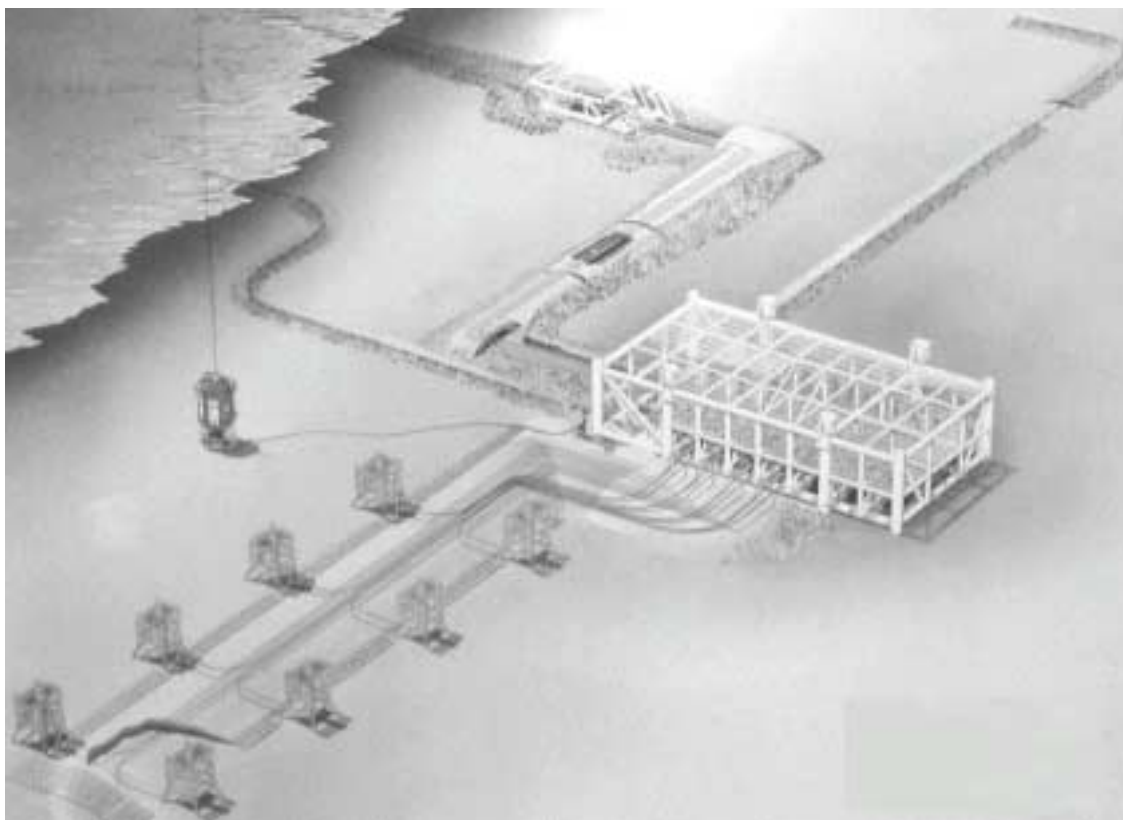


Figure 2 Cluster Manifold Connected to Six Satellite Wells

Auxiliary connections to the manifold may be made to facilitate injection of scale and/or corrosion inhibitor and sometimes H₂S scavengers, often via umbilicals, as described in Sections 11 and 12.

6.2 DESIGN CODES

The design and construction codes available for manifold piping include BS EN 14161, PD 8010 Pt 2, ASME B31.3, and the DNV Rules. These codes specify allowable stresses for piping components manufactured from seamless pipe, plate, castings, forgings, and by HIP.

For high-pressure manifolds, Chapter IX of B31.3 allows the use of a yield stress based criterion for determining the allowable stress, and this should allow reduced metal thickness compared with standard allowable stresses. However, more severe fracture toughness property requirements are stipulated that may be difficult to achieve with some materials.

Pressure vessels are typically designed and constructed to either ASME VIII or to (BSI) PD 5500. BS EN 13445 is also likely to be used with increasing frequency in the future. That standard has the advantage of giving presumption of conformity to the European Pressure Equipment Directive.

6.3 TYPICAL FABRICATION

Manifold piping is commonly sized in the 50–400 mm diameter range, with wall thicknesses up to around 80 mm. Fabrication may be by welded tees, extrusions, HIP tees in sections containing several outlets, or from pipe with 'sweepolet' or 'weldolet' (or

similar proprietary) branch connections. For subsea design, a minimum of welding is advantageous, and weld profiles should be of reasonably smooth finish to avoid crevices—potential sites of corrosion and stress concentrations—and to facilitate painting.

The external surfaces of manifold piping and vessels, whether carbon steel or CRA, should always be coated for corrosion protection and to reduce anode drain on the CP system. However, if the items are to be coated with thermal insulation, then consideration should be given to applying an anti-corrosion coating (see Section 14).

6.4 DUTIES

Subsea manifold duties include:

- producing reservoir fluids—oil, gas and produced water
- injection water which could be raw or treated sea water, wash water or produced water
- injection gas for storage or productivity enhancement.

The material requirements for each of these duties are dependent on the corrosivity of the fluids and the life span of the field development.

6.5 MATERIALS OPTIONS FOR PIPING AND VESSELS

Subsea manifolds are usually highly critical assemblies, the functional loss of which would have severe consequences for production. Hence materials selection for manifold piping and vessels should reflect the consequential requirement for high reliability and controlled resistance to corrosion that would avoid fluid leakage in service. Manifold piping is often of complex and compact design, and selected materials need to be commercially available in all the required product forms, and capable of being fabricated by conventional processes.

The first choice material for all hydrocarbon duties is usually a CRA of appropriate strength and fracture toughness to give a reliable, minimum weight facility. This is valid when corrosion rate assessments for manifold equipment in carbon steel are not practically possible during the design life because monitoring for erosion and corrosion is considered too difficult. However if the field life is short, typically less than 10 years, and the hydrocarbon fluids are benign, then carbon steel with a suitable corrosion allowance may be appropriate.

For CRAs the primary options include:

- duplex and superduplex stainless steel
- internally clad carbon steel, typically using Alloy 625.

However, under certain specific conditions the following may be considered suitable:

- super-austenitic stainless steel
- Alloys 625, 825, 24 (UNS S34565).

Water injection and gas lift manifold piping will usually be constructed of carbon steel with corrosion allowance, as the water is de-aerated and the gas for injection is dehydrated. Where the quality of the injection water cannot be guaranteed to meet the usual criteria, and where the flowlines to the manifold are plastic-lined, consumption of residual oxygen

by corrosion will not occur upstream of the manifold, hence the use of a CRA for the manifold piping may need to be considered, e.g. 22%Cr duplex stainless steel. Where injection water is not treated, then superduplex stainless steel and titanium are the optimum selections for high pressure, ambient temperature, raw seawater. For non-treated injection gas, carbon steel or CRA may be selected according to the corrosivity of the gas.

Whenever H₂S is present in the hydrocarbon fluids, ISO 15156/NACE MR0175 should be applied. The further level of testing to NACE TM0177 and TM0284 to assess resistance of the materials to SSC and HIC respectively, should also be considered.

For manifold piping fasteners see Section 9.

6.6 HUB AND FLANGE CONNECTORS

The preferred materials for hub connectors are forged CRA and weld-clad carbon manganese or low alloy steels.

Under most process conditions, duplex or superduplex stainless steels will be the CRA material of choice. Good manufacturing controls are required to ensure homogeneous, fine-grained microstructures, free from third phase precipitates.

External surfaces of CRA pipework and hubs should be protected with a high integrity coating in order to prevent hydrogen charging and embrittlement (see Appendix III). This is particularly important for weld zones, external changes in section, and locations of potentially high stress.

In-service stresses should be fully analysed and catered for in design. Additional bending stresses imposed as a result of poor fit-up should be avoided.

It is also common practice to select CRA weld overlaid carbon manganese or low alloy steel for hub/ROV connectors. Care needs to be exercised in the selection of the CRA–substrate combinations as a brittle fusion line can develop, e.g. Alloy 625 and/or 725 weld overlays on AISI 4130 and 8630. Post weld heat treatment (PWHT) has been found to exacerbate this problem. It is therefore recommended that high strength low alloy steels of this type be avoided. Failures have occurred in the brittle fusion line due to a combination of:

- high tensile residual stress
- high localized concentration of hydrogen
- the presence of a sensitive microstructure.

Particular attention should be paid to the joint design (see below) and to ensuring low-hydrogen welding consumables are specified (< 2 ppm hydrogen).

Suggested alternative combinations include Alloy 625-clad ASTM A182 Grade F22 or ASTM A 694 Grade F65, with restricted carbon and carbon equivalent values. In these cases, PWHT of the component after application of the weld overlay has been found to be beneficial. However, in many cases a double PWHT will be required.

Where weld overlaid hubs in low alloy or carbon manganese steel are specified, particular attention needs to be paid to the potential for the development of a narrow brittle zone (in the order of 5–10 µm) at or near the fusion zone, and should be assessed on a case-by-case basis. Again, the application of high quality external coatings to prevent hydrogen charging will be required.

Equally important is weld bevel design—the buttering of the CRA weld overlay onto a 90° weld bevel is not recommended (Figure 3).

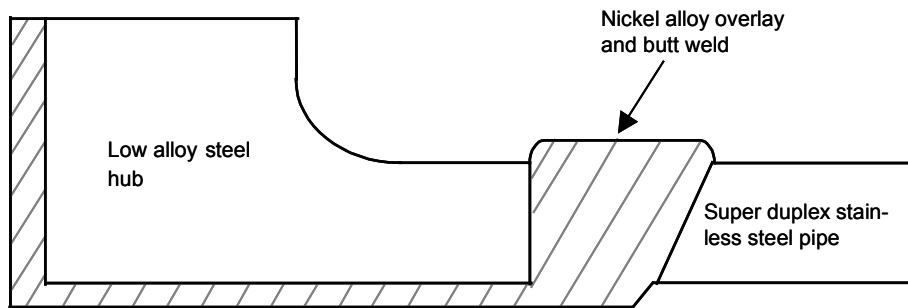
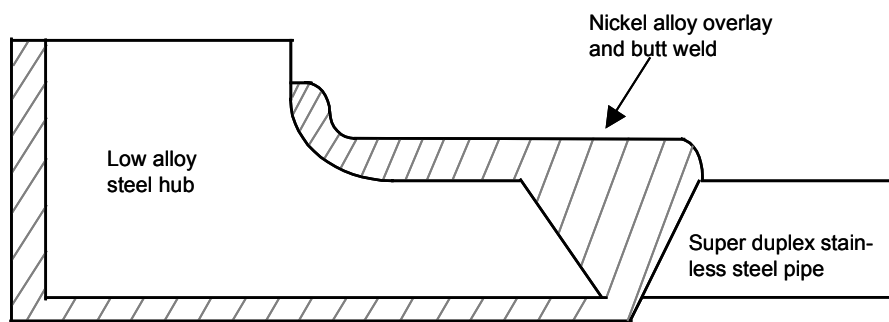
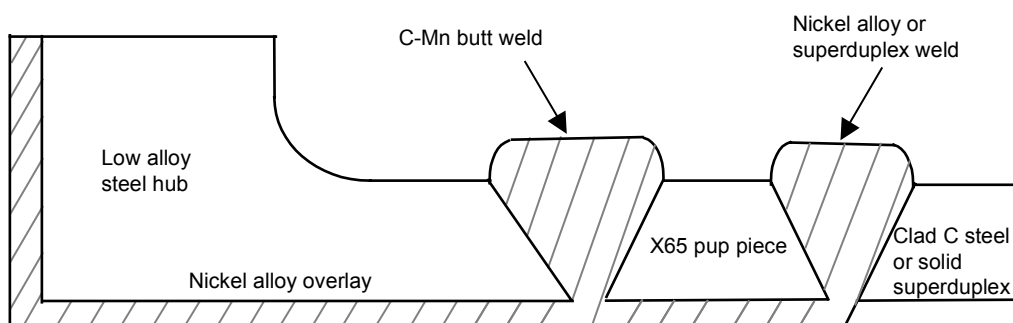


Figure 3 Undesirable Design Detail for Connector

Use of a standard 30° bevel is recommended along with continuation of the nickel alloy overlay around the hub radius so that the HAZ in the low alloy steel exposed to the seawater in the event of coating failure is located in a relatively low stress region (Figure 4a). An alternative recommended design incorporates a carbon steel pup-piece, welded to the hub and post-weld heat-treated as an assembly. This can then be welded to the superduplex stainless steel or CRA-clad piping without further PWHT as shown in Figure 4b.



4a



4b

Figures 4a and 4b Preferred Design Details for Connectors (typical)

Where carbon steel hubs or flanges are mated to CRA hubs or flanges, it is recommended that the mating face of the carbon steel material is fully weld overlaid with Alloy 625.

6.7 MULTIPHASE PUMPS

Multiphase pumps are becoming an increasingly attractive method to increase well productivity, and may be incorporated into Christmas tree flowbases, into production manifolds or may be stand-alone assemblies. The designs are proprietary and are individually customized for each specific application. Due to the relatively high velocities and turbulence in the pumps, CRAs are considered essential in every case, typically either duplex or superduplex stainless steel for the casings and internals wetted by the production fluids.

Pumps are usually of the multi-stage cartridge type such that the cylindrical casing is designed and constructed to pressure vessel codes.

Internals may require the application erosion resistant materials when sand production is expected, though some designs aim to maintain relatively low velocities within the pump, thereby avoiding excessive rates of erosion.

7 FLOWLINES AND RISERS

7.1 INTRODUCTION

This section describes the function and service conditions of subsea flowlines and risers, discusses the operational and economic parameters of their design, and indicates current recommended practice on materials selection and fabrication. Areas of application include:

- flowlines from subsea Christmas trees to production manifolds (and between cluster trees)
- flowlines from production manifolds to seabed terminations such as PLEMs (pipeline end manifolds)
- vertical riser assemblies from the seabed to the processing unit (platform or floating production unit)
- flowlines from production manifolds to processing units via catenary risers.

7.2 SERVICE

Subsea flowlines and risers may be used to carry the following fluids:

- production fluids
- injection/wash water
- injection gas
- chemicals
- heating medium.

Production fluids will be untreated, will probably contain water and CO₂, and are therefore likely to be corrosive. H₂S may also be present.

Injection and wash water are normally de-oxygenated seawater and/or reinjected formation water, although increasing use is being made of untreated seawater. Injection gas is usually processed, dry, and non-corrosive; but wet gas, sometimes with increased levels of CO₂ and H₂S from fluid processing, and highly corrosive, is also injected.

7.3 SUBSEA FLOWLINE DESIGN

7.3.1 Flowlines from Christmas Trees to Manifolds (and between Cluster Trees)

Flowlines from subsea Christmas trees to the manifolds (sometimes called jumpers) may be flexible piping (See Section 10) or rigid pipework. In the latter case the pipework may be designed to either a process pipework code (e.g. ASME B31.3) or a pipeline code (BSI PD 8010 Pt 2, ASME B31.4 or B31.8, or DNV OS-F101). These lines are normally short and, if in rigid pipe, usually installed as prefabricated spool pieces.

7.3.2 Flowlines from Manifold to Processing Unit

The processing unit may be a production platform, floating production unit or onshore facility. Flowlines between the manifold and the processing unit (also called inter-field or infield lines) may vary in length from, typically, 1 km to over 60 km. Short lines may be in flexible pipe but most are rigid, metallic pipelines installed by conventional laybarge, by