

DEP SPECIFICATION

**SELECTION OF MATERIALS FOR LIFE CYCLE
PERFORMANCE (UPSTREAM EQUIPMENT) – MATERIALS
SELECTION AND CORROSION MANAGEMENT**

DEP 39.01.10.11-Gen.

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DESIGN AND ENGINEERING PRACTICE

DEM1



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1. INTRODUCTION

1.1 SCOPE

This DEP specifies requirements and gives recommendations for the process of selecting materials for upstream production systems from the reservoir to the export point. It includes corrosion control for carbon steel with corrosion inhibition.

Part of the process of selecting materials is to ensure suitability throughout the operational “run and maintain” phase. This introduces multiple aspects of corrosion management in this DEP.

Detailed materials selection for specific equipment and accessories is covered in DEP 39.01.10.12-Gen.

This DEP provides useful references to materials standards that can be applied to upstream facilities.

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

This DEP is a revision of the same number dated February 2016; see (1.5) regarding the changes.

1.2 DISTRIBUTION, INTENDED USE AND REGULATORY CONSIDERATIONS

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Any authorised access to DEPs does not for that reason constitute an authorisation to any documents, data or information to which the DEPs may refer.

This DEP is intended for use in facilities related to oil production and gas handling. This DEP may also be applied in other similar facilities.

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

If national and/or local regulations exist in which some of the requirements could be more stringent than in this DEP, the Contractor shall determine by careful scrutiny which of the requirements are the more stringent and which combination of requirements will be acceptable with regards to the safety, environmental, economic and legal aspects.

In all cases, the Contractor shall inform the Principal of any deviation from the requirements of this DEP which is considered to be necessary in order to comply with national and/or local regulations.

The Principal may then negotiate with the Authorities concerned, the objective being to obtain agreement to follow this DEP as closely as possible.

1.3 DEFINITIONS

1.3.1 General definitions

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

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

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

The word **shall** indicates a requirement.

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

The word **should** indicates a recommendation.

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

1.3.2 Specific definitions

Term	Definition
Corrosion Allowance	The additional wall thickness that is provided to compensate for the expected loss of wall thickness due to corrosion under the intended operating conditions. This term is used for both the total estimated wall thickness reduction of carbon steel in service (also called the Service Life Corrosion), and the design (installed) corrosion allowance.
Corrosion Loop	Grouping of piping, pipelines, vessels, tanks and equipment that have similar corrosion or degradation threats, and similar process conditions and hence the same generic inspection requirements. Corrosion loops were named sub-systems in the previous versions of this DEP and DEP 30.10.02.14-Gen.
General Corrosion	The loss of wall thickness progressing at approximately the same rate over much of the surface of a metal component. It normally affects more than 10 % of the surface area and the variation in loss in wall thickness is less than 1.3 mm (50 mils).
Inhibitor Availability	The time as a percentage of the total operating time of a system (e.g., pipeline) that corrosion inhibitor is injected at a concentration that will enable corrosion control to below the defined inhibited corrosion rate (normally obtained from testing).
Localised Corrosion	The loss of wall thickness at discrete sites. It affects less than 10 % of the surface area or the loss of wall thickness shows variations of more than 1.3 mm (50 mils).
Pipeline	A system of pipes and other components used for the transportation of fluids, between facilities. A pipeline extends from pig trap to pig trap (including the pig traps), or, if no pig trap is fitted, to the first isolation valve within the plant boundaries or a more inward valve if so nominated. The terms flowlines, trunklines, in-field lines, gathering lines, delivery lines may be used for a pipeline.
Pitting	Extremely localised wall thinning. There is little consensus in the industry as to a strict quantitative definition of pitting. Most definitions imply that the depth of attack exceeds the width.
Safety Critical Element	An item of equipment (or structure) whose failure could lead to the release of a Major Hazard or whose purpose is to prevent or limit the consequences of a major incident, excluding business loss (refer to Safety Critical Element Manual SR.14.11269).

1.3.3 Abbreviations

Term	Definition
AC	Atmospheric Corrosion
BOL	Bottom Of Line
CA	Corrosion Allowance
CE	Carbon Equivalent
CFD	Computational Fluid Dynamics
CIMS	Corrosion and Inspection Management System (software)
CMF	Corrosion Management Framework
CMM	Corrosion Management Manual
CORRAT	Proprietary Shell computer program for calculating corrosion rates (the most basic option of HYDROCOR)
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CS	Carbon Steel
CUI	Corrosion Under Insulation
CWC	Condensing Water Corrosion (new term for TOL corrosion)
FEED	Front End Engineering and Design
FMEA	Failure Mode and Effects Analysis
GRP	Glass reinforced plastic (fibreglass). Also known as FRP (fibre reinforced plastic) or GRE (glass reinforced epoxy)
HAZ	Heat Affected Zone
HDPE	High Density Polyethylene
HE	Hydrogen Embrittlement
HEMP	Hazards and Effects Management Process
HIC	Hydrogen-Induced Cracking (also called step-wise cracking, SWC)
HRC	Rockwell Hardness
HV	Vickers Hardness
HYDROCOR	Proprietary Shell computer program for calculating corrosion rates
IOW	Integrity Operating Window

Term	Definition
JT	Joule-Thompson
LAT	Lowest Ambient Temperature
LCC	Life Cycle Costing
LDT	Lowest Design Temperature
LPR	Linear Polarisation Resistance
MIC	Microbiologically Induced Corrosion
NACE	National Association of Corrosion Engineers
NGL	Natural Gas Liquids
OR&A	Operations Readiness and Assurance
PWC	Preferential Weld Corrosion
RMP	Run and Maintain Practice
S-RBI	Shell Risk Based Inspection (methodology)
SCC	Stress Corrosion Cracking
SLC	Service life corrosion (total estimated wall thickness reduction of carbon steel over the life of a project)
SOHIC	Stress-Oriented Hydrogen-Induced Cracking
SPPS	University of Tulsa's Sand Production Pipe Saver program
SSC	Sulphide Stress Cracking
SWC	Step-Wise Cracking (also called hydrogen-induced cracking, HIC)
TOL	Top of Line

1.4 CROSS-REFERENCES

Where cross-references to other parts of this DEP are made, the referenced section or clause number is shown in brackets (). Other documents referenced by this DEP are listed in (10).

1.5 SUMMARY OF MAIN CHANGES

This DEP is a revision of the DEP of the same number dated February 2016. The only changes are to DEP cross-references to reflect changes in the DEP library in 2017.

1.6 COMMENTS ON THIS DEP

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

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

1.7 DUAL UNITS

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

1.8 NON NORMATIVE TEXT (COMMENTARY)

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

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

2. BASIS FOR MATERIALS SELECTION

The corrosion management process is depicted in Figure 1. It assumes that a Corrosion Management System description has been developed as part of the Company Management System (i.e. the organisation, responsibilities and policies related to corrosion management are in place).

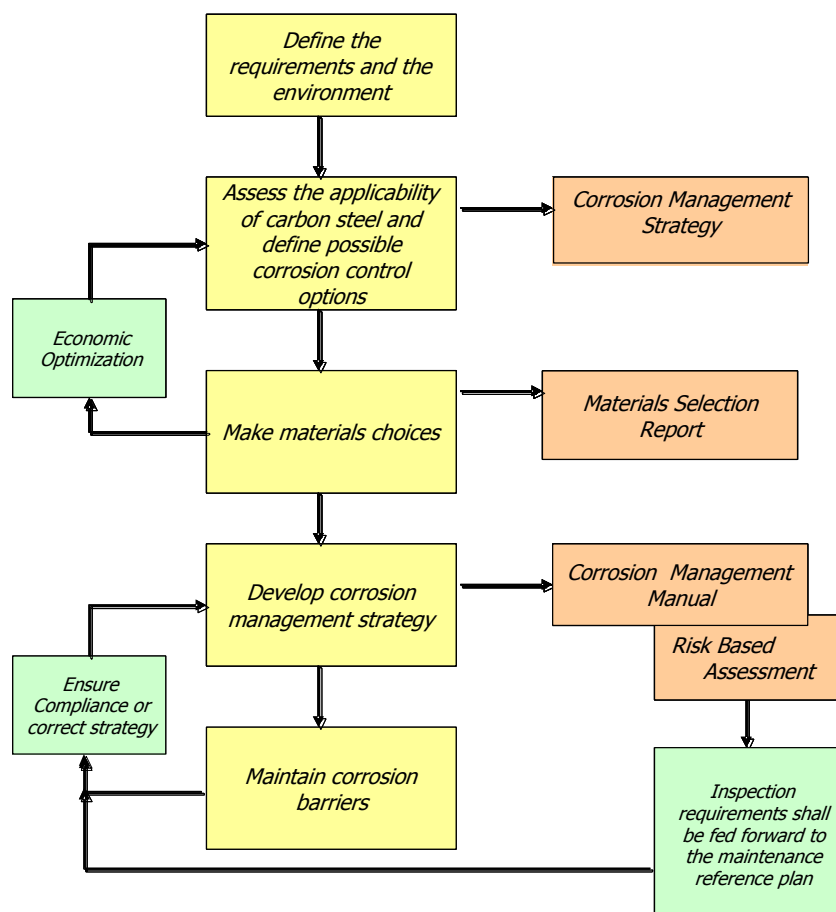
For a given project the initial corrosion management strategy will determine the overall approach to materials selection.

The process of selecting materials involves short-listing technically acceptable materials for an application and then selecting the most cost-effective option for the required operational life, consistent with relevant Health, Safety and Environmental aspects, Sustainable Development, Technical Integrity and operational constraints.

The process of materials selection is often multi-variable, and may require several iterations before an optimal solution can be obtained. Part of this process should be to assess which systems require materials optimisation and which can use standard materials selection guidelines.

The Corrosion Management Framework (CMF) described in this DEP provides a structure to capture the materials selection and define the corrosion controls needed to achieve the design intent over the life of the facility or installation.

Figure 1 Corrosion management process



3. HAZARD AND EFFECTS MANAGEMENT

1. Materials selection shall be consistent with the HSE Hazards and Effect Management Process (HEMP).

This process identifies and assesses HSE hazards, implements barriers, control and recovery measures, and maintains a documented demonstration that major HSSE risks have been reduced to a level that is As Low as Reasonably Practicable (ALARP).

4. CORROSION MANAGEMENT

4.1 GENERAL

1. Threats that lead to the degradation of materials and the possibility of unacceptable equipment failure shall be identified and documented as per (4.1, Item 5).
2. A barrier to prevent a material degradation threat leading to equipment failure SHALL [PS] be implemented for all safety critical elements.
3. Management of barriers to materials degradation shall be implemented in accordance with the Corrosion Management Framework specified in (APPENDIX A).
4. For all projects, the materials selection shall be based on the threats defined in the "threats and barriers" matrix (Appendix A, Table A.4).
 - a. In addition, it may be necessary to add project specific threats.
 - b. Against each one of these threats, at least one barrier shall be defined.
5. All defined barriers shall be designed and implemented to enable control of material degradation for the design life.
6. A failure mode and effects analysis (APPENDIX G) shall be carried out as an integral part of the preliminary corrosion management framework risk assessment during the SELECT phase and used as the basis for the Corrosion Management Manual in the EXECUTE phase.

4.2 CORROSION MANAGEMENT ELEMENTS

4.2.1 General

1. The Corrosion Management Framework and other relevant documentation that describe the materials selection and corrosion management strategy shall be provided to the team(s) responsible for commissioning and operations. As a minimum this should include:
 - a. Corrosion management framework system document (if not already available).
 - b. Updated materials selection document (from the project DEFINE phase).
 - c. Corrosion risk assessment (e.g., FMEA) used to identify the integrity threats.
 - d. Corrosion Management Manual as described in (4.2.2) and (APPENDIX A).
 - e. Populated corrosion and inspection data management database (including line list).
 - f. Inspection plan.

4.2.2 Corrosion management manual

1. At the materials selection stage (preliminary work in the SELECT phase, final work in the DEFINE phase) the facility shall be divided into systems, each characterised by a generic description of the fluid contained (e.g., oil processing, fuel gas, fire-water, etc.), and corrosion loops which are exposed to similar corrosion threats, and are expected to have (broadly) similar corrosion failure probabilities.
2. The realistic corrosion threats and barriers and/ or corrosion control shall be identified for each corrosion loop, so that their effectiveness or compliance status can be assessed initially during the project itself and later during the operational phase.
3. For each facility, the CMM and associated corrosion control documents shall define the key parameters that are required to be controlled to safeguard the relevant barriers.
 - a. These parameters may also be captured in an Integrity Operating Window (IOW) document.
 - b. The CMM or IOW should also identify the relevant performance indicators and the actions that must be taken by the Principal's operations, maintenance, inspection and materials and corrosion staff if excursions from the defined conditions occur.
4. All new CMMs shall follow the elements and structure given in (APPENDIX A). The project CMM should align with the CMM currently in use at the receiving Operating Unit.

4.2.3 Corrosion control methods

1. If corrosion control is dependent upon corrosion control measures requiring operational activity, these measures shall be documented in such a way that all the requirements and performance checks for the chosen control method, and those responsible for their execution, are defined and made available at handover of the project to operations.

4.2.4 Sphering and pigging

1. If sphering and pigging of a pipeline or flowline is required for corrosion management, a pigging program shall be defined including pig type, frequency and operational responsibilities as part of the pipeline integrity management plan.

4.2.5 Chemical injection requirements

1. If corrosion control is to be based on the use of chemical injection (corrosion inhibitor, pH control chemical, oxygen scavenger, or biocide), documentation shall provide details of the process to be followed, the chemical(s) to be used and their concentration(s) in the process stream and the required availability of the corrosion control system.
 - a. Selection and qualification of corrosion inhibition chemicals shall be subject to approval by the Principal.
2. The operating requirements and responsibilities of operations staff for the everyday running of the corrosion control program shall be defined in the appropriate corrosion control document (e.g., CMM or IOW).
3. A detailed review of possible interruptions of chemical injection and their control shall be carried out to demonstrate that the required availability of the inhibitor system can be achieved.
4. Key performance indicators for the corrosion control systems shall be developed as part of the project documentation.

4.2.6 Gas Dehydration

1. If corrosion control is based upon gas drying, the required gas dew point shall be clearly defined as part of the design basis for the responsible operations staff.
 - a. Operational requirements and controls of glycol systems shall be defined in the appropriate operating procedures and related IOWs or corrosion control document.
2. Requirements for a corrosion allowance downstream of gas drying facilities shall be determined based on the reliability of the gas drying unit, as part of the (risk based) corrosion assessment.

4.2.7 Inspection and corrosion monitoring

1. The project documentation shall include requirements for inspection and corrosion monitoring to ensure that the barriers for equipment integrity can be verified during the design life, on the following basis.
 - a. The requirements are justified and provide guidance on frequency and locations of inspections.
 - b. The need or otherwise for a baseline inspection is addressed.
 - c. The inspection and corrosion monitoring requirements for facilities are based on assessment using the S-RBI methodology (OG.04.30260 "Risk and Reliability Management (RRM), Version 2, manual for S-RBI, S-RCM and SIFpro™, or SR14.12961 "Shell Risk Based Inspection (S-RBI) Version 3").
 - d. The inspection and corrosion monitoring requirements for pipelines are based on assessment using w-PIMS (SR 13.13167 "w-PIMS Introduction Functional Specification Release 2.0")
2. Where systems require the permanent installation of corrosion and condition monitoring devices, the types of instruments to be used, the required sensitivity range, and the required response time shall be stated and the locations shown on system drawings.
3. Corrosion monitoring by means of coupons or probes shall not be the only method used to assess materials degradation; refer to (7.2.11, Item 1).
4. Inspection plans to verify compliance of barriers to materials degradation shall be produced for safety critical systems.
5. Activities required to monitor and verify the barriers shall be included in the maintenance reference plan as per SR.12.13047 Maintenance Reference Plan.

4.2.8 Corrosion inspection data management system

A substantial amount of inspection and monitoring data will be collected over the life of a facility and will be analysed, for example, with RBI systems.

1. For greenfield projects, the global standard electronic data management system (CIMS) shall be used to capture operating and design parameters, and corrosion and integrity related design information normally contained in the corrosion management manual (4.2.2).
 - a. Where a project feeds into existing facilities, the existing data management system should be used.

4.2.9 Corrosion awareness

1. During the commissioning phase, operations and maintenance staff and other relevant discipline staff should receive training in corrosion control in a program defined by the Materials & Corrosion Technical Authority of the Principal.

5. MATERIALS SELECTION WORK PROCESS

5.1 GENERAL

1. An initial materials selection including a corrosion management strategy shall be completed during the project SELECT phase.

The purpose is to identify unusually high cost materials, which feeds into the Level 1 (CAPEX and OPEX) cost estimate (+40 %/-25 %).

2. For long-lead and/or bulk items (e.g., downhole tubing and line pipe), key materials decisions should be made as early as possible in the project, preferably during the SELECT phase, i.e., ahead of FEED.
3. If the new project will tie into existing installations, the suitability of the materials in place for the envisaged process conditions, their current condition, and the existing corrosion management strategy should be ascertained in the SELECT phase.
4. Operations personnel shall be included in the project team, or consulted, for interfaces with existing installations.
5. The (detailed) materials selection shall be completed in the DEFINE phase.
6. The selection process shall be based on one of the three following options:
 - a. Standard materials selection.
 - i. Selection is based upon the stated information on the environmental conditions for each system and the use of technically proven and economically acceptable materials. Refer to DEP 39.01.10.12-Gen.
 - ii. In general, materials optimisation is not performed. Some optimisation may be required on some process systems, if conditions are encountered that are not adequately covered in this DEP, or if the user wishes to consider other materials choices, in the interest of potential cost savings.
 - iii. For carbon steel applications, the process of corrosion control option selection, corrosion control system availability and corrosion allowance selection follows the requirements of (7).
 - b. Material optimisation (specialist consultation).
 - i. For systems where alternative (cheaper) materials may be feasible based on experience elsewhere with individual alloys or generic groups of alloys under similar conditions, the materials selection may be optimised.
 - ii. The materials performance data that are used for the optimisation is verified by a discipline materials specialist.
 - c. Experimental evaluation (specialist consultation).
 - i. Experimental work may be necessary to evaluate materials and corrosion control chemicals for specific applications.
 - ii. Experimental evaluation shall be carried out in accordance with the material testing methodology selected for the failure modes anticipated.
 - iii. Where required to assess the suitability of the lowest cost option, it should be carried out ahead of the Field Development Plan (FDP, in the project select phase).
 - iv. Refer to DEP 39.01.10.12-Gen., Appendix B for guidance on the qualification of materials.

5.2 STANDARD MATERIALS SELECTION

1. Standard materials selection process shall include the following steps:
 - a. Define the requirements and the environment:
 - i. Define the intended design life of the equipment.
 - ii. Define the internal and external environments for the equipment, including any non-routine or non-operational conditions that might be encountered, refer to Table 1.
 - iii. The variables characterising the corrosive environment shall be quantified for normal operating conditions and for unusual or upset conditions.
 - b. Assess the applicability of carbon steel and define possible corrosion control options, refer to (7):
 - i. Establish the suitability of carbon steel as a baseline against which to compare more corrosion resistant, and possibly more costly, alternatives.
 - ii. Calculate the Service Life Corrosion (SLC) for the proposed operating conditions.
 - iii. Identify possible corrosion control options to protect the steel from premature failure. These may include chemical corrosion control, coatings, cathodic protection and control of process fluids, e.g., pH stabilization and dehydration.
 - c. Identify other materials options:
 - i. Corrosion resistant alloys
 - ii. Other options, in particular for pipelines:
 - 1). High Density Polyethylene (HDPE) liners for oil and water service.
 - 2). Internal Fusion Bonded Epoxy (FBE) coating for water injection service.
 - 3). Corrosion Resistant Alloy (CRA) clad or lined pipe, in particular for very corrosive and sour conditions.
 - 4). Glass Reinforced Plastic (GRP) for water injection, oil and gas production.
 - d. Make (initial) materials choices
 - i. Apply the requirements for each type of equipment as per DEP 39.01.10.12-Gen.
 - ii. In addition to corrosion mechanisms, mechanical properties including strength and toughness should be included in the assessment of choice of material.
 - e. Develop corrosion management framework (CMF)
 - i. Define the corrosion management requirements in accordance with (Appendix A) of this DEP.
 - ii. Include both internal and external degradation threats
 - iii. If the material selected is fully corrosion resistant under all anticipated operating conditions, record the limits of corrosion resistance in the Corrosion Management Manual for the facility
 - f. Assess economics of choices
 - i. Where the likelihood of failure of corrosion control is high, the consequences should be taken into account, e.g., enhanced corrosion control measures, and enhanced inspection and repair.

- ii. Operations personnel should be involved in the life cycle cost assessment to ensure all operating costs are included.
- iii. The life cycle cost assessment should be completed as part of the initial materials selection report to enable the initial material choices to be made.
- g. Develop live documents and data management systems
 - i. The project documents shall be updated whenever there are (approved) materials substitutions (e.g., during procurement and fabrication), and changes to the corrosion control system.
 - ii. Responsibilities and competence requirements shall be defined in the CMF.

6. INFORMATION REQUIRED AND FACTORS AFFECTING MATERIALS SELECTION

6.1 GENERAL

1. Requirements for corrosion resistance and mechanical properties of welds for both internal and external environments shall be in accordance with all of the following:
 - a. (APPENDIX B);
 - b. DEP 39.01.10.12-Gen. Section 4;
 - c. the relevant equipment welding DEP.
2. Design for external corrosion, which is normally controlled by corrosion barriers such as coatings and cathodic protection, should not result in an added external corrosion allowance for equipment and piping.

6.2 INTERNAL ENVIRONMENTS

6.2.1 Definition of critical operating and environmental factors

Table 1 summarises the information necessary to perform materials selection for commonly encountered environments. The information required for materials selection is shown in the second column, and the additional information required for Service Life Corrosion calculations (for carbon steel) is shown in the third column. Also refer to DEP 01.00.01.30-Gen. for definitions of temperature, pressure and toxicity levels.

Table 1 Information required for materials selection for internal environments as part of design basis

System	Minimum information required for materials selection	Additional information required for final service life corrosion calculation
Equipment carrying produced fluids	type of fluid presence of free water mol % CO ₂ ppm/mol% H ₂ S (at known pressure) pH (estimation of in situ pH and where possible measure the pH) chloride level (of produced, condensed, and in-situ concentrated (flushed) waters) operating pressure: range operating temperature: range design pressure bubble point pressure design temperature min. blow down temperature presence of O ₂ or free S (free S can be in the gas or condensate) presence of bacteria sand content design life ambient temperature upset temperature presence of mercury water dew point in gas systems water content of the gas amine type and loading fluid properties (density and viscosity) concentration of organic acids (C1 – C4)	flow assurance study including hydrate control measure the full stream molar composition whether inhibitors are to be injected flow regime(s) flow velocities of all phases water cut in crude oil systems water content in glycol (where added for corrosion or hydrate control) Alkalinity expressed as HCO ₃ – content of water, or preferably, full water composition projected operating pressure and temperature profile over life of project heat transfer coefficients of coating systems used (pipelines) reservoir type (carbonate or sandstone)
Utility systems	type of fluid presence of free water presence of oxygen minimum and maximum. design temperatures inhibition philosophy flow rates	

System	Minimum information required for materials selection	Additional information required for final service life corrosion calculation
Equipment carrying sea water, including water injection and fire water	maximum service temperature oxygen content chloride content presence of bacteria stagnant, intermittent or continually flowing flow rate concentration of biocide (e.g., hypochlorite and residual chlorine) operating mode; dry or wet when not in use	for water injection systems the anticipated amount and particle sizes of corrosion products are often required to manage well sand control efficiency.

1. The anticipated corrosion losses shall be calculated for the normal operating conditions as well as any other condition that may happen during the operational phase, such as interruptions of inhibition (corrosion during the maximum acceptable time that no inhibitor is available), shut-ins, hydrotest, well treatments and wet conditions in normally dry systems.
2. If a material in the projected service environment (including short operating excursions) could fail by corrosion cracking at the design pressure and worst-case temperature (for the material being considered) an alternative material or corrosion control shall be implemented.
3. The likelihood of bacterial corrosion during the life of the facility (including the construction, commissioning and operational phases) shall be assessed for all equipment and a control strategy defined as part of the design basis. This may include materials selection such as the use of resistant materials like GRP.
4. In liquid full systems, the partial pressure of CO₂ and/or H₂S to be used in corrosion calculations shall be the fugacity (similar to the partial pressure, while accounting for the non-ideal behaviour of the gas) that would exist in a virtual gas phase in equilibrium with the aqueous phase in the system,.
5. The ingress of oxygen into producing systems is an operationally avoidable upset condition and shall not be accommodated in the material selection but the consequences of failure to control oxygen should be assessed as part of the FMEA.
6. If a full water analysis is not available, at least the chloride ion (Cl⁻), the bicarbonate (HCO₃⁻) and organic acid contents should be obtained.
 - a. The Cl⁻ content is essential for determining the likelihood of cracking. The HCO₃⁻ and organic acid concentration will affect the pH and therefore the corrosion rate, in particular the CO₂ corrosion rate.
 - b. Where possible a production chemist should be consulted to check the validity of the data and calculate the pH.
7. It should be established whether the water phase comes from produced water or condensed water so that reasonable assumptions can be made about the likely chloride content and pH values.
8. If no other information is available, the values given in Table 2 should be used for the initial materials selection.
9. An accurate analysis of the chloride content and assessment of the pH shall be used for the final materials section.

10. Where concentration of chlorides can occur (e.g., in flashing process conditions or carryover in the gas phase of separators) an assessment of the likely concentration shall be made and used for the design basis. Refer to DEP 39.01.10.12-Gen, Section 3.2.2.
11. Specialist advice should be sought from the Materials & Corrosion Technical Authority of the Principal for assessment of organic acids and elemental sulphur.

Table 2 Initial material selection parameters

Gas production environments (produced gas with or without produced water)*:	
pH	3.5
chloride	1 g/L NaCl (condensation water only), 250 g/L NaCl (formation water produced)
Oil production environments:	
pH	4.5
chloride	165 g/L NaCl (100 g/L dissolved chloride)
Note *: not necessarily applicable for associated gas	

6.2.2 Flow regime evaluation

1. The likely flow regime shall be determined, particularly for pipelines that operate in stratified flow conditions and therefore experience different corrosion conditions on the top and bottom surfaces.
2. Flow regimes may be estimated from flow maps or derived from computer flow simulations including as incorporated in HYDROCOR.

Flow conditions also affect the potential erosion and erosion-corrosion (APPENDIX D). Table 3 outlines factors controlling flow conditions and corrosion.

3. Shut-in conditions should be assessed for all equipment (e.g., dead-legs).

Table 3 Factors affecting flow regime and corrosion

Equipment	Factors affecting flow condition and corrosion
Downhole tubing – oil well ⁽¹⁾	Tubing walls are oil-wetted² (and therefore not subject to corrosion) if produced water is carried in the oil phase. The limit of water-carrying capability of hydrocarbons depends upon composition, temperature, API gravity, angle of deviation of the well and flow rate and can be determined by laboratory tests or computer models. If water production increases with time, tubing walls may become water-wetted and hence subject to corrosion. With increased water production the chloride content may increase as well, which can have serious implications for certain materials, in particular many CRAs.
Downhole tubing – gas well ⁽¹⁾	Condensation of water occurs when the gas drops below its water dew point temperature, which might be at a particular depth in the tubing, depending on the temperature profile. Above this level, corrosion may occur as the water is carried as a mist with an annular film of water on the tubing surface. If water production increases with time, tubing walls may become water-wetted and hence subject to corrosion. With formation water production the chloride content may increase, which can have material degradation implications particularly for CRAs.
Downhole tubing - water injection or disposal well	The corrosivity of the injected water can vary from not corrosive (acceptable oxygen and bacteria control) to corrosive (produced water with dissolved CO₂/H₂S) to very corrosive (raw water injection).
Downhole tubing - EOR activities	Impact of steam quality on the integrity of steam piping, wellhead and downhole tubing should be assessed with particular emphasis on caustic corrosion/cracking. Effect of temperature cycle during Huff/Puff and upsets on material properties (strain hardening, fatigue) should be assessed. Impact of polymer/chemical residuals and degradation by-products on tubing and on corrosion inhibitor performance in production facilities should be assessed.
Pipeline – Stratified flow regime	The internal top and bottom of pipelines experience different corrosion conditions, especially when there is a hydrocarbon layer on the top of the liquid water phase. The Condensing Water Corrosion (CWC) corrosion rate is influenced by the condensation rate and gas composition and is not mitigated by buffering salts flowing in bottom-of-line waters. CWC corrosion can be controlled by glycol injection for sweet service. Batch inhibitors may also be used, including sour service. Methanol injection should not be used for sour service because of potential for flashing. The rate of condensation is governed by the heat transfer coefficient of the pipeline. Hence pipeline insulation affects the potential CWC corrosion. CWC corrosion is a concern when there is a high condensation rate; possible causes are: A significant change in the insulating properties of the external coating of a pipeline or in the external ambient temperature (e.g., un-insulated river crossing) Pipeline intersections Significant quantities of organic acids condensing with the water The inlet temperature is above 80 °C (176 °F); this situation is aggravated by a high partial pressure of CO₂.