ervia

European Commission

# ERVIA CCS PRE-FEED STUDY

## Material Selection Philosophy - Cork

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# Contents

Holds ..... iv
Glossary ..... v
References ..... vii

1 INTRODUCTION AND SCOPE ..... 1
1.1 Project Background ..... 1
1.2 Scope ..... 1

2 GENERAL PHILOSOPHY ..... 2
2.1 General ..... 2
2.2 Material Suitability Assessment – In-plant Piping and Equipment ..... 2
2.3 Material Suitability Assessment – Pipelines ..... 2
2.4 Design Life ..... 3
2.5 Materials Selection Documentation ..... 3
2.6 Material Specifications ..... 4
2.7 Review of Downstream Deliverables ..... 5

3 INTERNAL CORROSION ..... 6
3.1 $CO_2$ Corrosion ..... 6
3.2 Pitting Corrosion ..... 6
3.3 Microbially Influenced Corrosion (MIC) ..... 6
3.4 Amine Corrosion ..... 7
3.5 Cooling Water Corrosion ..... 7
3.6 Seawater Corrosion ..... 7
3.7 Process Chemicals ..... 7
3.8 Galvanic Corrosion ..... 8

4 ENVIRONMENTAL CRACKING THREATS ..... 9
4.1 General ..... 9
4.2 Chloride Stress Corrosion Cracking (ClSCC) ..... 9
4.3 Amine Stress Corrosion Cracking ..... 9
4.4 Caustic Stress Corrosion Cracking ..... 9
4.5 Ammonia Stress Corrosion Cracking ..... 10

5 EXTERNAL CORROSION ..... 11
5.1 Atmospheric Corrosion ..... 11
5.2 Corrosion Under Insulation (CUI) ..... 11
5.3 Soil Corrosion ..... 12
5.4 External Bolting ..... 12
5.5 Small Bore Tubing ..... 13

6 LOW TEMPERATURE EMBRITTLEMENT ..... 14
6.1 General ..... 14
6.2 Process Piping ..... 14
6.3 Utility Piping ..... 14
6.4 Pipelines and Equipment ..... 14

7 CORROSION MANAGEMENT ..... 15
7.1 Corrosion Monitoring and Inhibition ..... 15
7.2 Cathodic Protection ..... 15
7.2.1 In-Plant Cathodic Protection ..... 15
7.2.2 Pipeline Cathodic Protection ..... 16

# Tables

Table 2-1 – Plant Design Life Summary....3
Table 2-2 – Minimum Required Information for MSDs....3
Table 3-1 - Material Selection for Typical Process Plant Chemicals....7
Table 5-1 - External Coating Requirements....11
Table 5-2 - Recommended Bolting Materials....13
Table 6-1 – Allowable MDMT for Common Piping Materials....14
Table 7-1 - Typical Corrosion Monitoring Techniques....15

# Holds

| HOLDS | Description | Responsibility |
|---|---|---|
| N/A | | |
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| | | |

# Glossary

| Term | Definition |
|---|---|
| ALARP | As Low as Reasonably Practicable |
| ASTM | American Society for Testing and Materials |
| CA | Corrosion Allowance |
| CCGT | Combined Cycle Gas Turbine |
| CPF | Central Processing Facility |
| ClSCC | Chloride Stress Corrosion Cracking |
| CCS | Carbon Capture and Storage |
| CP | Cathodic Protection |
| cPVC | Chlorinated Polyvinyl Chloride |
| CRA | Corrosion Resistant Alloy |
| CS | Carbon Steel |
| CUI | Corrosion Under Insulation |
| DC | Direct Current |
| DNV | Det Norske Veritas |
| DSS | Duplex Stainless Steel |
| FEED | Front End Engineering Design |
| ER | Electrical Resistance |
| FRP | Fibre Reinforced Plastic |
| HDPE | High Density Polyethylene |
| ICCP | Impressed Current Cathodic Protection |
| ISO | International Organization for Standardization |
| LAS | Low Alloy Steel |
| LPR | Linear Polarisation Resistance |
| LTCS | Low Temperature Carbon Steel |
| MDMT | Minimum Design Metal Temperature |
| MDS | Mechanical Data Sheet |
| MIC | Microbially Influenced Corrosion |

| | |
|---|---|
| MMO | Mixed Metal Oxide |
| MoC | Material of Construction |
| MSD | Material Selection Diagram |
| NACE | National Association of Corrosion Engineers |
| PREN | Pitting Resistance Equivalent Number |
| PTFE | Polytetraflouroethylene |
| PWHT | Post Weld Heat Treatment |
| SDSS | Super Duplex Stainless Steel |
| SS | Stainless Steel |
| TBC | To Be Confirmed |
| UT | Ultrasonic Examination |

# References


1. MDE1234-RPS-01-CX-RP-Z-0001 Study Basis – Cork
2. NACE SP 0403 Avoiding Caustic Stress Corrosion Cracking of Refinery Equipment and Piping
3. NACE SP 0294 Design, Fabrication, and Inspection of Storage Tank Systems for Concentrated Fresh and Process Sulfuric Acid and Oleum at Ambient Temperatures
4. NACE SP 0472 Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel Weldments in Corrosive Petroleum Refining Environments
5. NACE SP 0391 Materials for the Handling and Storage of Commercial Concentrated (90 to 100%) Sulfuric Acid at Ambient Temperatures
6. NACE SP 0407 Format, Content and Guidelines for Developing a Materials Selection Diagram
7. ISO 12944-1 Paints and varnishes. Corrosion protection of steel structures by protective paint systems. Part 1: General introduction
8. ISO 12944-2 Paints and varnishes. Corrosion protection of steel structures by protective paint systems. Part 2: Classification of environments
9. ISO 12944-5 Paints and varnishes. Corrosion protection of steel structures by protective paint systems. Part 5: Protective paint systems
10. ISO 21457 Petroleum, petrochemical and natural gas industries Materials selection and corrosion control for oil and gas production systems
11. API RP 571 Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
12. API RP 581 Risk Based Inspection Methodology
13. ASTM A193 Standard Specification for Alloy-Steel and Stainless Steel Bolting for High Temperature or High Pressure Service and Other Special Purpose Applications
14. ASTM A194 Standard Specification for Carbon Steel, Alloy Steel, and Stainless Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both
15. ASTM A320 Standard Specification for Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service
16. ASTM B805 Standard Specification for Precipitation Hardening Nickel Alloys Bar and Wire
17. ASTM F1428 Standard Specification for Aluminum Particle-Filled Basecoat/Organic or Inorganic Topcoat, Corrosion Protective Coatings for Fasteners
18. DNV RP F104 Design and Operation of $CO_2$ Pipelines

# 1 INTRODUCTION AND SCOPE

## 1.1 Project Background

Ervia is assessing how Carbon Capture and Storage (CCS), located close to large-scale $CO_2$ emitters can play a role in reducing Ireland's $CO_2$ emissions. A technical feasibility study on the potential for large-scale CCS in Ireland was completed by Ervia in 2020.

The general location of Aghada Power Station in County Cork was selected as a potential site for a Central Processing Facility (CPF) for liquefaction, storage, and export of $CO_2$ overseas via a new marine jetty. The CPF will cater for $CO_2$ captured at 3 emitter locations (Whitegate Power Station, Irving Oil Whitegate Refinery and Aghada CCGT). A new $CO_2$ gas pipeline gathering network will transport $CO_2$ from the emitters to the CPF.

Ervia has appointed RPS / Bechtel to carry out a Pre-FEED study that involves a detailed assessment of the key CPF, pipeline and storage infrastructure necessary to condition, compress, transport and store liquid $CO_2$ at Cork harbour for subsequent loading onto ships for export. (Note: The scope of this project does not include the carbon capture facilities at each emitter).

Additionally, the new marine jetty in Cork will also be used for import of liquid $CO_2$. This scenario considers the regasification of liquid $CO_2$ at Cork for transport via pipeline to the Inch terminal which is the link to indigenous offshore permanent storage at the depleted Kinsale Head Gas Field.

## 1.2 Scope

This document provides the basis and guidance for the materials selection on the Project. This document identifies credible corrosion threats and material damage mechanisms expected within the project, along with the proposed mitigations to these, to ensure safe and reliable operation throughout the maintained design life of the plant. This document also defines the metallurgical deliverables required for the project and the minimum requirements for these.

This document does not detail any specific material selection but sets out the basis to be used for material selection during the design phases of the project. The material selection basis discussed within this document has been established by a combination of international codes and standards, industry practice and Contractor experience/lessons learned.

# 2 GENERAL PHILOSOPHY

## 2.1 General

The base material selection for the majority of process equipment and piping shall be carbon steel (CS). Under certain operating conditions and or environments, alternative materials shall be employed such as low alloy steels (LAS) and corrosion resistant alloys (CRA).

CS is generally more vulnerable to corrosion than CRA, but metal loss/wall thinning is typically more predictable and uniform than that found in CRA. CRA when selected within their safe operating domain, other than in specific scenarios are not expected to be subject to any corrosion when selected. If unforeseen circumstances occur and CRAs are subject to corrosion, failure can be extremely rapid, localised and unpredictable.

Fabrication and material processing requirements for CS are generally well understood, steel mills and fabricators globally, with sufficient surveillance, can be expected to meet the material requirements of industry with regard to CS. The material requirements for LAS and CRA are less universally understood than for CS, lapses in control of chemical composition and thermal processing can lead to unexpected and rapid degradation of these materials during service.

For the reasons discussed in the above paragraphs, the Project philosophy will be to retain CS as the material of construction (MoC) where it is reasonable to do so.

## 2.2 Material Suitability Assessment – In-plant Piping and Equipment

Material suitability shall be assessed against all the threats discussed within this document that are applicable to the service in question. For corrosion and degradation mechanisms that are predictable and measurable, normal operating conditions shall be used as the basis for verifying material suitability for the conditions. For example, $CO_2$ corrosion is assessed based on operating conditions.

As discussed in section 2.1 CS will be the base material selection, depending on the predicted total corrosion over the design life, corrosion allowance (CA) shall be applied for all CS piping and equipment with the exception of heat exchanger tubes. The minimum CA shall be 1.5 mm for non-corrosive services increasing to 3 mm and 6 mm as required. If the predicted total corrosion over the design life exceeds 6 mm, CRA will be considered.

Where degradation mechanisms prevail that exhibit a sudden and or unpredictable threat to the integrity of equipment such as cracking mechanisms, the design conditions shall be considered to assess these threats.

In all cases selected materials shall be resistant to deterioration in the following conditions:

- Normal operating conditions.
- Abnormal conditions, including conditions created during start-up, normal shutdown and emergency shutdowns. These include factors such as fluid flow variations and transient conditions that might exist before a stable normal operation is established.
- Upset conditions. Upset conditions may have significant effects on mechanical design and affect material selection.
- Special operations, including mechanical and chemical cleaning, cyclic or intermittent operations, steam-out operations and anticipated process modifications.

## 2.3 Material Suitability Assessment – Pipelines

Pipeline corrosion assessment shall account for the same factors described for in-plant piping above. For $CO_2$ import and export pipelines the guidance of DNV RP F104 shall also be considered.

Due to the length of pipelines, corrosion assessment shall be more detailed, accounting for factors such as flow regime which is not practicable for the complex geometries associated with in-plant piping. Corrosion allowance for pipelines shall be more precisely calculated to avoid unnecessary capital expenditure.

The guidance of DNV RP F104 shall also be used to develop a fracture control plan for the project $CO_2$ pipelines to mitigate fracture initiation and propagation.

## 2.4 Design Life

Per the pre-FEED study basis MDE1234-RPS-01-CX-RP-Z-0001 the following design lives are considered:

- Plant - 25 years
- Pipeline - 40 years

Materials selected shall be suitable to ensure the risk of loss of containment for the design life, in the maintained plant, is as low as reasonably practicable (ALARP). Certain items (identified in Table 2-1) will be selected based on shorter more practicable design lives and intended for replacement or life extension assessment at 5 or 10 year intervals to coincide with planned shut downs. Where corrosion allowances are specified, the thickness shall be based on the total predicted corrosion over the period identified in table 2-1 below:

**Table 2-1 – Plant Design Life Summary**

| Item | Design life in years |
|---|---|
| Reactors and regenerators | 25 |
| Pressure vessels (columns, drums) and heat exchanger pressure retaining components | 25 |
| Removable trays & internals | 10 |
| Pump casings | 25 |
| Rotating machinery casings | 25 |
| Low alloy and carbon steel heat exchanger tube bundles | 10 |
| Corrosion resistant alloy heat exchanger tube bundles | 25 |
| In-plant Piping | 25 |

## 2.5 Materials Selection Documentation

Where available, project specifications shall detail the purchase requirements of project materials and control processes such as welding that can impact material mechanical properties and corrosion resistance. Material selection documentation shall detail the material selection and specification, these documents are referenced within.

Material Selection Diagrams (MSDs) shall be prepared for each process flow diagram (PFD). The MSDs shall incorporate the design considerations discussed within this document. FEED MSDs shall be prepared in accordance with NACE SP0407 except that table 1 of NACE SP0407 shall be modified per table 2-2 below.

**Table 2-2 – Minimum Required Information for MSDs**

| Equipment Label | Components | Materials Information | Requirement |
|---|---|---|---|
| Vessels, Reactors, Columns, Filters etc | Shell (SH), fixed internals<br>Removable Internals (INT) | Materials<br>Corrosion Allowance (CA) for fixed parts<br>CRA cladding or weld overlay-min. thickness | Mandatory |
| Shell and Tube Heat Exchanger (HEX) | Shell (SH)<br>Channel(s) (CH)<br>Tubes (T)<br>Tube sheet(s) (TS) | Materials<br>Corrosion Allowance (CA)<br>Cladding or weld overlay internal coatings or linings-min. thickness | Mandatory |

| Equipment Label | Components | Materials Information | Requirement |
|---|---|---|---|
| | Baffles (B)<br>Floating head cover (FH) | Materials<br>Corrosion Allowance (CA) | Optional |
| Air Cooled Heat Exchanger (A/C) | Headers (H)<br>Tubes (T) | Materials<br>Corrosion Allowance (CA) | Mandatory |
| Fired Heaters | Radiant/Convection Tubes | Materials<br>Corrosion Allowance | Mandatory |
| Centrifugal Pumps | Casing<br>Impeller | Materials<br>or API 610 Annex H Material class | Mandatory |
| Piping | Piping,<br>Valve trim | Materials<br>Corrosion Allowance (CA) | Mandatory |
| Tanks | Floor,<br>Wall,<br>Roof | Materials<br>Corrosion Allowance (CA)<br>Internal Coatings or Lining<br>Internal/External CP | Mandatory |
| Fabricated Equipment (e.g., compressors, skid mounted equipment etc.) | Typically Manufacturer's Standard for the intended service | Materials<br>Corrosion Allowance (CA) -optional<br>Internal coatings or linings | Mandatory if not manufacturers standard |

## 2.6 Material Specifications

Material and fabrication controls discussed within this document shall be incorporated into project specifications developed by the materials and corrosion discipline in FEED stage. Project specifications will be developed to be specific and applicable to the project. The following design aspects shall be governed by specifications:

- Welding and Fabrication, (Pipelines, Vessels and Equipment, Piping, Structural Steel, Tanks)
- Pipeline Components
- Protective Coatings and Linings
- Galvanising
- Cathodic Protection
- Hydrotest Water Quality and Drying
- Insulation (Hot, Cold and Acoustic)
- Passive Fire Protection
- Temporary Corrosion Protection (Preservation)
- HDPE Bonding
- Traceability

Contractor experience and lessons learned show that adequate manufacturer/supplier engagement and surveillance is vital for quality control/assurance. It is not feasible to generate project specifications that are 100% applicable to all the different items of equipment that form a complex processing plant.

## 2.7 Review of Downstream Deliverables

In order to ensure the proper implementation of the requirements of this philosophy and the MSDs across the project, the Materials and Corrosion group will perform the following key activities:

- Review of Mechanical Data Sheets (MDS) at an early stage, including review & endorsement of the first and all subsequent issues.
- Review of P&IDs prior to HAZOP including review & endorsement of the first and all subsequent issues.

# 3 INTERNAL CORROSION

## 3.1 $CO_2$ Corrosion

$CO_2$ corrosion occurs when $CO_2$ dissolves in free water present in the process, forming carbonic acid. $CO_2$ corrosion of carbon steel is uniform and predictable. Temperature pH and partial pressure of $CO_2$ are the key drivers of corrosion rate. Commercially available software are available for prediction of corrosion rate in CS which can be used to validate its selection and assess the requirement for corrosion allowance or decision to select CRAs. If the predicted corrosion rate of CS is too high to be practically mitigated by a corrosion allowance and chemical inhibition, an appropriate CRA will be selected in lieu of CS. Whilst $CO_2$ corrosion is typically a predictable threat in upstream operations, in carbon capture facilities the high $CO_2$ partial pressures and moderate temperatures will mean that any wet conditions would result in aggressive corrosion rates in carbon steel. All commercially available $CO_2$ corrosion rate prediction software would result in unacceptable corrosion rates for carbon steel equipment conveying captured $CO_2$ in the presence of liquid water. Therefore, justification of carbon steel selection for piping and equipment conveying $CO_2$ is dependent on maintaining a dry condition. The definition of this dry condition is defined as follows:

A stream is considered dry when the water dew point at the operational pressure is at least 10 °C lower than the minimum operating temperature for the system. Such systems are not subject to electrochemical corrosion and no corrosion prediction is required. Reference ISO 21457. Where this criterion is not met CRAs will be required for handling captured $CO_2$.

Contractor will utilise Larkton CM $CO_2$ corrosion modelling for screening potential corrosion rates in potential operating scenarios.

## 3.2 Pitting Corrosion

Pitting corrosion is a highly localized form of corrosion that can be caused by a number of species found in processing plant but is most commonly caused by the presence of halide especially chlorides in the service. Pitting corrosion is hard to predict and detect using NDE techniques. Pitting corrosion involves concentrated material loss over a small area which increases the rate at which wall thickness is lost when compared to general corrosion. Where pitting corrosion is assessed to be too great to accommodate with a corrosion allowance for CS, CRA shall be selected.

CRA materials can be more vulnerable to pitting corrosion than CS and prone to very rapid failure in chloride containing services. Selection of CRA shall account for pitting threat and CRA materials shall be selected that have an appropriate pitting resistance for the service. Pitting resistance of CRA can be defined by the Pitting Resistance Equivalent Number (PREN). Selection of austenitic and duplex SS alloys in halide containing environments will be preceded by a detailed review for the possibility of localized pitting and crevice corrosion.

## 3.3 Microbially Influenced Corrosion (MIC)

MIC is the acceleration of other forms of corrosion due to the presence of microorganisms in the form of a biofilm on the metal surface. The biofilm localises corrosion which concentrates material loss to a smaller area and consequently accelerates loss of wall thickness. The microorganisms within the biofilm also produce acidic by-products, these by-products can further accelerate corrosion and cause corrosion without the assistance of other mechanisms.

The microorganisms that contribute to MIC are waterborne and typically introduced to systems during pressure or commissioning testing of systems. Once a biofilm is established it is extremely difficult to completely remove, it is also difficult to predict exactly which parts of a system will be affected.

Most materials are vulnerable to MIC to some extent, grades 304/304L and 316/316L SS are extremely vulnerable to MIC and through wall pits can develop in weeks if MIC is not controlled. CS also experiences accelerated corrosion rates due to MIC but not as drastically as 304 and 316 SS. SS grades containing > 3% Molybdenum offer superior resistance due to an increased pitting resistance equivalent number (PREN) but no alloys are considered completely immune to MIC. Microbial activity in the presence on chlorides can lower typical safe threshold limits of chloride and temperature for a given alloy, and PREN alone is insufficient mitigation to MIC.

The only sure mitigation of MIC is to avoid the introduction of microorganisms into systems. Water used for hydrotest and commissioning tests on austenitic SS piping and equipment should be of demineralised quality and properly treated with biocide. Residence time of water within a system shall be limited and thorough draining and drying cycles shall be performed after testing to remove all residual moisture and prevent bacterial growth within systems. Hydrotest water quality and drying requirements shall be detailed in a project construction specification and rigorously enforced.

## 3.4 Amine Corrosion

Amines are not corrosive to CS however, the acid gas species ($CO_2$) that amines absorb are corrosive in the presence of free water as discussed in sections 3.1. The effect of this corrosion can be exacerbated by the presence of Heat Stable Amine Salts (HSAS). Amine corrosion can be mitigated by controlling the flow velocity of the process to limit desorption of corrosive species and selection of CRA materials.

## 3.5 Cooling Water Corrosion

Cooling water systems are subject to numerous corrosion threats including but not limited to, general corrosion, chloride pitting, under deposit corrosion, MIC and fouling. Typically, corrosion in cooling water piping can be mitigated with corrosion allowance. The most vulnerable sections of cooling water systems are heat exchanger tubes for which corrosion allowance is not applicable. Careful evaluation of cooling water composition and temperature is required to ensure appropriate CRA selection for heat exchanger tubes. Chloride concentration can be expected to increase in recirculating cooling water systems due to the evaporation of water.

A general limit of 200 ppm chloride shall be considered for 316L SS tube bundles in cooling water service. Above 200 ppm CRAs with higher PREN than 316L SS shall be considered.

## 3.6 Seawater Corrosion

Due to the chloride concentration, oxygenated seawater is highly corrosive to Carbon Steel, corrosion rates are temperature dependant but corrosion rates ≈ 0.5 mm/yr are considered typical.

Seawater is an effective electrolyte, consequently there is a significant risk of galvanic corrosion between dissimilar metal connections depending on their relative positions in the electrochemical series.

In Seawater service Microbially Influenced Corrosion (MIC) can also occur. MIC can lead to rapid failures in both CS and SS piping as discussed in section 3.3. A particular MIC phenomenon known as grooving corrosion has been previously documented in deaerated water transmission pipelines.

Where possible, HDPE and FRP shall be selected for seawater intake piping and equipment (if any) as these non-metallic materials are fully resistant to seawater corrosion. Any submerged CS equipment shall be protected by a combination of robust protective coating and CP. For temperatures up to 30° C CRA selected for aerated seawater piping shall have a PREN of 40 or greater such as 2507 super duplex stainless steel (SDSS).

## 3.7 Process Chemicals

Many common process plant chemicals are corrosive in concentrated form, Table 3-1 lists a non-exhaustive selection of typical processing plant chemicals and the appropriate material selection or guide to selection for those chemicals:

**Table 3-1 - Material Selection for Typical Process Plant Chemicals**

| Chemical | Primary MoC | Remarks |
|---|---|---|
| Hydrochloric Acid | Hastelloy B-3 | Temperature shall be limited to 40°C<br>CS + PTFE lined may be considered |
| Sodium Hypochlorite | cPVC | Hastelloy C276 and Titanium may be considered |
| Ferric Chloride | Hastelloy C276 | CS + PTFE lined may be considered |

| | | |
|---|---|---|
| Oxygen Scavenger | 316L SS | |
| Scale Inhibitor | 316L SS | SS typically selected for cleanliness |
| Biocide (Non-Oxidising) | 316L SS | |
| MEG | 316L SS | |
| Anti-Foam | 316L SS | |

## 3.8 Galvanic Corrosion

Galvanic corrosion is a concern for both external and internal surfaces of piping and equipment. It is caused by the coupling of materials with different electrochemical potential in the presence of a corrosive electrolyte, causing a loss of materials from the less noble material. This is not generally a problem with de-aerated process fluids. Externally, the problem can arise in buried or immersed situations. Where aerated fluids are concerned, various techniques (such as the local coating of the cathode) can mitigate this. A critical influencing factor is the anode to cathode surface area ratio. Designs that result in an unfavourable anode to cathode ratios shall be avoided. An example of this is where CRA piping connects to a lined piece of equipment, this can result in a holiday in the lining becoming an anode site with a small surface area in comparison with the large cathode surface area of the CRA pipe. Such instances will be mitigated by the introduction of a lined CRA spool of a length at least 20 times the diameter of the pipe at the connection to the lined equipment.

Coupling of dissimilar metals should be minimized to prevent galvanic corrosion. Where unavoidable the risk should be assessed. Formal assessments are not required for use of combinations that are well proven by historical evidence (e.g. SS316 trim in CS valves or use of galvanised low bolting for above ground flange connections in SS316 piping).

Designs that are proven to lead to accelerated galvanic corrosion such as using graphite packing and seat and seal materials in sea water duty valves or coupling carbon steel with titanium in seawater service shall be avoided.

# 4 ENVIRONMENTAL CRACKING THREATS

## 4.1 General

In services that promote stress cracking, socket weld fittings and slip on flanges shall not be used, pressure retaining welds shall be full penetration butt welds. Should pressure retaining fillet welds be unavoidable, a minimum of two passes shall be made.

Cold worked components shall not be employed in stress cracking services unless subject to a normalising or solution annealing heat treatment after cold working.

## 4.2 Chloride Stress Corrosion Cracking (ClSCC)

ClSCC affects austenitic and duplex SS materials exposed to chlorides and water in presence of oxygen and/or a low environmental pH at temperatures above 50°C. It can occur both internally and externally.

Internal ClSCC is a prominent risk during start up and shut down when moisture and oxygen ingress is possible, procedures shall be developed to control moisture and oxygen ingress.

Externally, austenitic stainless steel and duplex stainless steel materials should be coated to minimise exposure to water and chlorides refer Table 5-1. Where impractical to externally paint more resistant grades will be selected.

The use of unprotected austenitic SS bolting presents a risk of failure due to ClSCC and shall be avoided.

## 4.3 Amine Stress Corrosion Cracking

Amine SCC is most prevalent in lean amine service, temperature and amine type are the key factors affecting the likelihood of amine SCC but it can occur at ambient temperatures and in all amines. Mono Ethanolamine (MEA) is the most aggressive amine for causing amine SCC.

PWHT shall be applied to CS materials in lean and rich amine service regardless of operating temperature and the amine. PWHT shall be applied in accordance with the guidance of NACE SP 0472. The tensile strength of CS materials in amine service shall be limited to 485 MPa (70 ksi).

## 4.4 Caustic Stress Corrosion Cracking

Caustic SCC affects CS materials in caustic service dependent on caustic concentration and temperature. Materials selection for caustic service shall follow the guidance of NACE SP 0403.

PWHT shall be applied to CS materials per the caustic service chart Figure 1. PWHT shall be applied in accordance with the guidance of NACE SP 0472. The tensile strength of CS materials in caustic service shall be limited to 485 MPa (70 ksi).

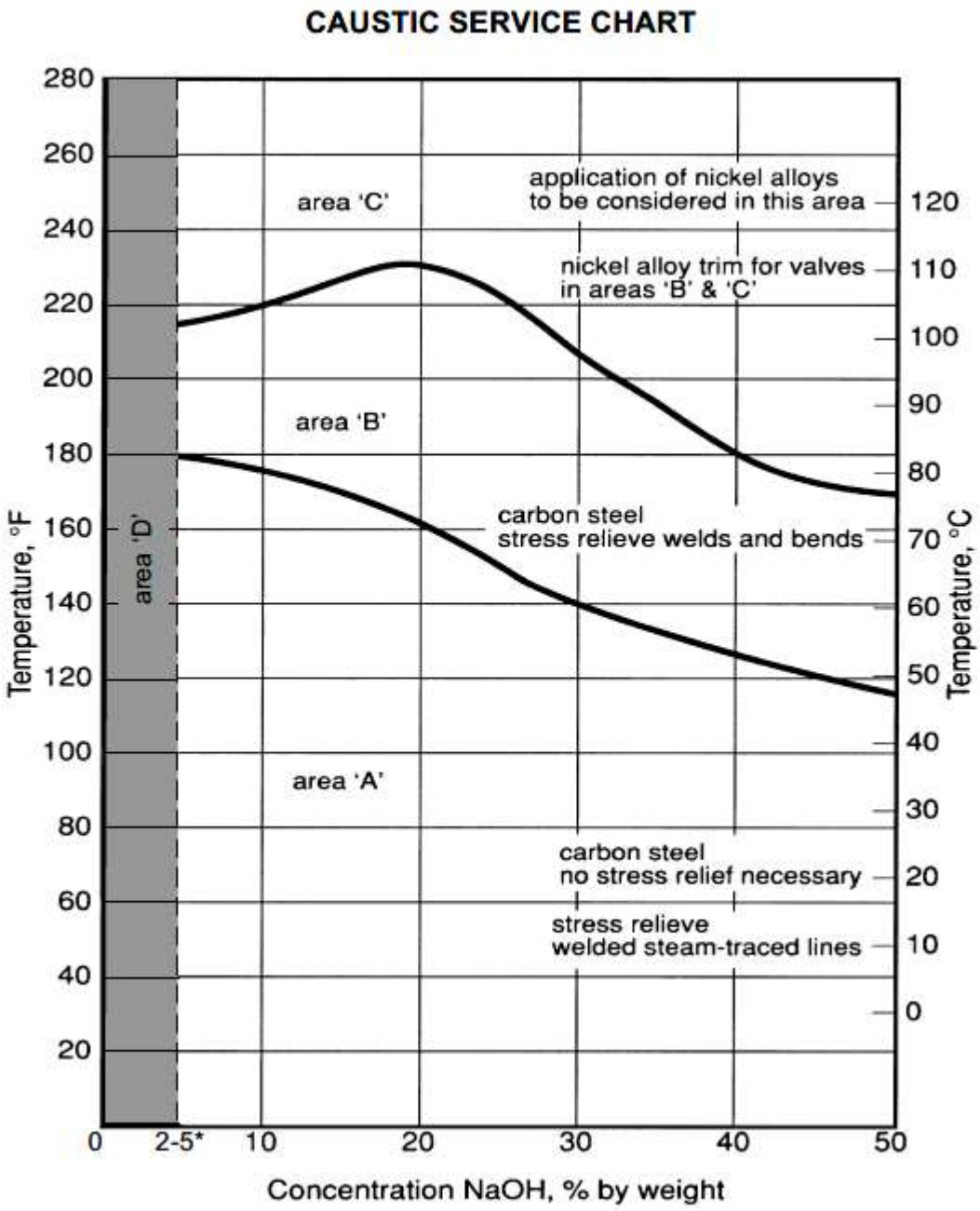


**Figure 1 - Caustic Service Graph (NACE SP 0403, 2015)**

## 4.5 Ammonia Stress Corrosion Cracking

Ammonia SCC can occur in CS in anhydrous ammonia streams i.e. <0.2% $H_2O$. Copper alloys are vulnerable to Ammonia SCC in aqueous ammonia service.

The minimum specified tensile strength of CS materials shall be limited to 485 MPa (70 ksi) and PWHT shall be applied to piping and equipment that could be exposed to anhydrous ammonia. PWHT shall be applied in accordance with the guidance of NACE SP 0472.

Copper containing alloys shall not be selected for ammonia service.

# 5 EXTERNAL CORROSION

## 5.1 Atmospheric Corrosion

The local atmospheric conditions are aggressive due to the coastal location and consequent saline conditions results in a coating systems classification for this project in accordance with ISO 12944 Parts 1 and 2 as C5 (Very high corrosivity). The C5 classification is defined as “Industrial areas with high humidity and aggressive atmosphere and coastal areas with high salinity”. External coatings shall be selected in accordance with ISO 12944-5 for corrosion category “C5” and high durability “H”.

All CS materials shall be externally coated to protect against atmospheric corrosion, CRAs shall be coated as detailed in Table 5-1. Maximum operating temperature selected shall consider the solar radiation or black body temperature of the item.

## 5.2 Corrosion Under Insulation (CUI)

CUI is caused by water, particularly chloride laden water, penetrating the external insulation. This leads to corrosion of CS, or pitting and stress corrosion cracking (SCC) of SS piping and equipment. The highest risk of this occurring is when hot / cold cycling leads to salt concentration. The corrosion often remains undetected until the insulation is removed for inspection, or when the corrosion causes leaks. CUI has been known to cause significant damage to plant.

It is important that insulation is applied only when it is necessary for the process, noise control, or fireproofing. Where protection of personnel from accidental contact with hot surfaces is required, cages shall be used instead of insulation.

Suitable coatings should be used to protect the metal surface from CUI and it is important that coating requirements are followed through for field joints.

The insulation materials selected should not retain water and should be chemically inert. Adequate sealing of the insulation and protrusions should also be ensured to prevent moisture ingress. The design and the orientation of such protrusions should be configured to aid effective water shedding.

The CUI threat is anticipated to be high due to the coastal location of the project and the different types of insulation required (acoustic, cold conservation, heat conservation).

The primary defence against CUI shall be the selection of robust coating systems in accordance with the applicable project coating specification.

All CS materials shall be externally coated to protect against CUI, CRAs shall be coated as detailed in Table 5-1.

**Table 5-1 - External Coating Requirements**

| Materials | Insulated/Uninsulated | Maximum operating temperature (apply coatings above specified temperature) |
|---|---|---|
| CS and LAS | Insulated and uninsulated | Coating required for all temperatures above 0°C |
| 4XX series Ferritic and Martensitic SS | Insulated and uninsulated | Coating required for all temperatures above 0°C |
| 304 series SS | Insulated and uninsulated | Coating required for all temperatures above 0°C |
| 316 series SS | Insulated | Coating required for all temperatures above 0°C |
| 316 series SS | Uninsulated | 50°C |
| 6Mo and other highly alloyed austenitic SS | Insulated or uninsulated | 120°C |
| Duplex SS | Uninsulated | 70°C |
| Duplex SS | Insulated | Coating required for all temperatures |

| Materials | Insulated/Uninsulated | Maximum operating temperature (apply coatings above specified temperature) |
|---|---|---|
| Super Duplex SS | Uninsulated | 90°C |
| Super Duplex SS | Insulated | Coating required for all temperatures |
| Alloy 825 | Insulated | Coating required for all temperatures |
| Alloy 825 | Uninsulated | 50°C |
| Alloy 625 and Higher Alloys (Hastelloys, Titanium etc) | Insulated or uninsulated | No coating required |

## 5.3 Soil Corrosion

Due to the coastal and industrial location soil at the project site will be chloride laden and consequently soil side corrosion will be aggressive. All buried piping and metallic equipment and pipelines shall be coated in accordance with the applicable project coating specification and subject to Cathodic Protection (CP) per section 7.2.

Where design constraints allow, non-metallic materials (HDPE and GRP/FRP) shall be selected for buried piping services as these are fully resistant to soil side corrosion.

Soil side corrosion can be exacerbated by to the presence of microorganisms, detailed soil survey's will be performed.

## 5.4 External Bolting

The project shall standardise as far as possible on low strength low alloy steel bolting regardless of the piping/flange material, bolting materials should follow table 5-2. Low alloy steel bolting shall be hot dip galvanised as standard per the applicable project galvanising specification.

Low alloy galvanised bolting is permitted for use in stainless steel piping systems. The propensity and consequence of austenitic stainless steel bolt failure due to ClSCC is far greater than any perceived threat of degradation as a result of galvanic corrosion.

Where the use of low alloy bolting is precluded due to minimum design temperature, any austenitic stainless steel bolting selected shall have an external coating system. The coating system shall consist of a ceramic-metallic base coat and fluorocarbon top coat that complies with ASTM F 1428 grade 4A or 4B.

High strength bolting i.e. bolting with a hardness > 34 HRC shall be avoided.

**Table 5-2 - Recommended Bolting Materials**

| Service Temperature (T) | Material | Material Specification | |
|---|---|---|---|
| | | Bolts | Nuts |
| T ≥ -29$^0$C | Carbon and Alloy Steel | ASTM A193 Grade B7 & B16 | ASTM A194 Grade 2H |
| -100$^0$C to -29$^0$C | Carbon and Alloy Steel | ASTM A320 Grade L7 or L43 | ASTM A194 Grade 7L |
| -50$^0$C to -29$^0$C | DSS / SDSS | ASTM A320 Grade L7 or L43 | ASTM A194 Grade 7L |
| -100$^0$C to -29$^0$C | Austenitic SS / 316L SS / Inconel 625 / Incoloy 825 | ASTM A320 Grade L7 or L43 | ASTM A194 Grade 7L |
| -196$^0$C to -100°C | Austenitic SS / 316L SS / Inconel 625 / Incoloy 825 | ASTM B805 Incoloy 925 | ASTM B805 Incoloy 925 |

## 5.5 Small Bore Tubing

Small bore (uncoated) tubing in non-sour service should be 6 Mo SS as a minimum to mitigate the atmospheric corrosion threat. A combination of 6 Mo tubing with 316L fittings and valves will be considered acceptable due the inherent increased thickness of fittings and valves reducing the propensity for CISCC in these components.

# 6 LOW TEMPERATURE EMBRITTLEMENT

## 6.1 General

Low temperature embrittlement is well documented and understood, however toughness issues even at ambient temperatures still occur in industry, primarily due to poor material and fabrication control. The following requirements shall be applied to mitigate the risk of low temperature embrittlement.

Code limits shall also be considered when selecting materials for low temperature service.

At this stage the project makes use of austenitic stainless steel grades at temperatures below the code limits for impact tested carbon steel. This is due to the known availability and ease of manufacture of stainless steel grades such as SS316/316L. Future phases of the project should assess the practicality of using lower alloyed grades of steel containing typically 3.5% nickel, to understand if cost, availability and fabricability could offer benefit to the project capital expenditure.

Table 6-1 below summarises the allowable temperature ranges for commonly selected materials for process plants:

**Table 6-1 – Allowable MDMT for Common Piping Materials**

| Material | Minimum Allowable MDMT (°C) |
|---|---|
| Carbon Steel | -29 |
| Low Temperature Carbon Steel | -46 |
| Duplex and Super Duplex Stainless Steel | -50 |
| Low Alloy Steel Bolting | -100 |
| Austenitic Stainless Steel (w/o impact testing) | -101 |
| Austenitic Stainless Steel (impact tested) | -196 |

## 6.2 Process Piping

To avoid mix-ups, the project philosophy shall be to standardise on impact tested components (LTCS grades) when carbon steel is selected regardless of the minimum design metal temperature (MDMT).

## 6.3 Utility Piping

All CS flanges shall be supplied in the normalized condition and impact tested regardless of service MDMT. Flange impact test temperature shall be -29 °C for all services, including where the MDMT is > -29 °C.

Flange impact test temperature shall be -46 °C for all services where the MDMT < -29 °C.

Where the MDMT is lower than -29 °C LTCS (i.e. Pipe and fitting material grades impact tested at -46 °C) shall be selected.

## 6.4 Pipelines and Equipment

Pipeline and equipment components shall be as required by the applicable design code.

Per section 2.3, a fracture control plan shall be developed for project pipelines in addition to code minimum requirements.

# 7 CORROSION MANAGEMENT

## 7.1 Corrosion Monitoring and Inhibition

A detailed strategy document shall be developed to assess and document the requirements for corrosion monitoring and chemical inhibition for all process and utility units once the plant configuration is finalised.

Corrosion monitoring shall be considered in areas of the plant where uniform measurable corrosion mechanisms are expected.

Where corrosion control is reliant on chemical inhibition, corrosion monitoring shall be employed to assess the dosing requirement and verification of corrosion inhibitor effectiveness.

Corrosion monitoring type shall be selected based on suitability for the specific location and the process/corrosion mechanism anticipated, Table 7-1 details common forms of corrosion monitoring device that may be employed on the project:

**Table 7-1 - Typical Corrosion Monitoring Techniques**

| Corrosion Monitoring Device | Remarks |
|---|---|
| Mass loss coupons | Offline metallic coupons that can be used to estimate the corrosion rate by the mass loss. Can be used externally to monitor CP system performance. |
| Electrical Resistance (ER) Probe | Intrusive probe that provides online, real time estimate of corrosion rate. |
| Linear Polarisation Resistance (LPR) Probe | Intrusive probe that provides online, real time estimate of corrosion rate. |
| Ultrasonic (UT) Wall Thickness Measurement | Non-intrusive corrosion assessment, can be used for fixed, online monitoring or periodic assessment of wall thickness loss. Numerous products and techniques are available for fixed and periodic assessment. |
| Fluid Chemical Sampling | Periodic chemical sampling is particularly relevant to monitor corrosion and chemical dosing rates of water systems. |

## 7.2 Cathodic Protection

A detailed CP philosophy and specification shall be developed for the project. The required CP systems shall be designed in accordance with the aforementioned philosophy and specification for all metallic surfaces that are buried including but not limited to:

- Buried metallic piping
- External tank bases
- Buried vessels
- Fire hydrants
- Import and Export pipelines

### 7.2.1 In-Plant Cathodic Protection

#### 7.2.1.1 Buried Piping

CP for underground steel piping within the CFP will be provided and shall be designed to be compatible with any existing CP systems.

Universal electrical continuity within the plant will be adopted as a design philosophy in accordance with EN 14505. There will be no provision made for electrical isolation at above/below ground interfaces. Isolation of pipelines is provided only at the battery limits of the CFP. Casings, if installed, shall be isolated from the carrier pipe.

The CP current could be large and optimization of current distribution is required. Impressed current anodes are recommended to be distributed throughout the protected piping network. Structures which may increase current demand include:

- Reinforcing steel in concrete;
- Steel supports and piling; and
- Electrical earthing systems.

#### 7.2.1.2 On Grade Tank Bases

CP shall be applied where tank base plates are in contact with soil or sand-based tank pads. To aid current distribution and decrease current demand, it is recommended to coat the underside (soil facing side) of tank base plate. The final current demand however is computed as if the tank base plate is 100% bare. The tank pad in contact with the coated steel base shall comprise clean and washed sand as described in API 651.

CP for tank bottoms should typically consist of the following (descriptions of items under the tank plates starting from the tank plate):

- Coating on the soil side (underside) of the tank floor plate in accordance with Project Painting Specification;
- A layer of 300-400 mm clean and washed sand;
- A CP system consisting of anodes (installed as a grid) and reference electrodes;
- A layer of 100 to 200 mm clean and washed sand; below the CP system
- A secondary containment of HDPE or other plastic liner, where applicable; approximately 400 to 600 mm below the base plates; and
- Foundation fill material.

#### 7.2.1.3 Tank and Vessel Internals

Impressed current Internal CP will be considered for tanks and vessels containing natural and other waters such as internal wetted surfaces of fire water tanks, glycol water tanks, tanks containing sour water, produced water etc. where it is deemed to control the expected corrosion.

All works for installation/attachment of internal CP equipment shall be completed before application of internal coatings.

The CP system or tank internals will mainly be an impressed current system using MMO anodes.

Automatic controls shall be installed to adjust the output of the rectifiers based on potential readings of the permanent reference electrodes.

Sacrificial anodes should be used for internal protection of hydrocarbon vessels and tanks containing a distinct corrosive water phase that separates at the bottom of these tanks and vessels. The surface where such waters separate should preferably be coated.

Potential monitoring of these sacrificial systems is not required. However, these systems should be designed for a minimum life commensurate with inspection and maintenance schedules.

### 7.2.2 Pipeline Cathodic Protection

The onshore buried pipelines will require Cathodic Protection. These pipelines need to be electrically isolated (monolithic joints) at the CPF as well as any other tie-in points.

It is possible that the CP current demand for the new pipelines is achieved by bonding to existing pipeline (same corridor) CP systems which have additional capacity to accommodate the current demand for the new pipelines for the design period. In such cases, new CP stations may not be required for the export pipelines.

Temporary CP, designed for a 2-year life, will be required in case of standalone ICCP systems. Pre-packaged sacrificial anodes shall be used for temporary protection. These will be disconnected prior to commissioning of the permanent impressed current system.

In areas of DC interference, measures to identify and mitigate interference (bonding, magnesium/zinc anode drains, use of insulating sheets and blocks, etc.) on the new pipelines need to be implemented immediately after the pipe lay.

Test stations shall be provided along the pipe route to allow monitoring throughout the design life.