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Review of Material Selection for Corrosion-Resistant Alloy Pipelines

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Abstract

The selection of materials for subsea pipelines is critical due to the highly corrosive nature of the environments, in which these pipelines operate. Traditionally, carbon steel has been used for non-corrosive applications or when an active corrosion management strategy is employed. However, the use of carbon steel is limited in situations where corrosive fluids, such as those containing chlorides, hydrogen sulfide (H_2S), and other aggressive substances, are present. In such cases, corrosion-resistant alloys (CRAs) offer a more effective alternative. This paper provides a comprehensive review of the material selection process for CRA pipelines, specifically focusing on corrosion mechanisms such as general corrosion, pitting, crevice corrosion, chloride stress corrosion cracking (CSCC), and hydrogen-induced stress cracking (HISC). The paper examines commonly used CRA materials, including duplex stainless steels, super duplex stainless steels, Alloy 825, and Alloy 625, comparing their performance under different subsea conditions. Resistance of each material to various forms of corrosion is discussed, along with considerations for operational and economic viability. The review highlights that while CRA pipelines typically have higher initial costs than carbon steel pipelines, they offer significant long-term savings by reducing corrosion maintenance, inspection, and repair costs. The review findings also emphasize the importance of proper CRA material selection, particularly in the presence of complex environmental factors such as high temperatures, high pressures, and the presence of chlorides and H_2S. The paper concludes that the appropriate use of CRA materials can significantly enhance pipeline integrity, extend operational lifespans, and prevent costly failures, making them a critical choice in the design and construction of subsea pipelines.

Keywords: Material selection; Corrosion-resistant alloy; Subsea pipelines; CRA metallurgically clad; Mechanically lined pipes.
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1. Introduction

The increasing operational challenges in the oil and gas industry, including deeper wells, higher pressures, and more aggressive environments, have amplified the need for materials with superior corrosion resistance. In this context, corrosion-resistant alloys (CRAs), particularly duplex and super duplex stainless steels, have emerged as essential components in the design and construction of hydrocarbon production infrastructure. These materials are capable of withstanding not only corrosive environments but also the mechanical stresses induced by high pressures and temperatures. Corrosion can result in catastrophic failures, leading to loss of production, safety risks, and significant economic costs. As the industry moves towards more extreme operating environments, CRAs and their variations like duplex and super duplex steels have become critical in ensuring the system integrity, extending the service life of assets and minimizing downtime. This paper explores the chemical compositions, properties, and applications of CRAs, duplex, and super duplex steels, focusing on their roles in mitigating corrosion in hydrocarbon production systems.

The material selection process for CRA subsea pipelines traditionally consists of two stages. Firstly, the whole range of engineering materials considered, and technically unacceptable ones are rejected. The technically acceptable materials are then reviewed on a cost basis and the cheapest suitable ones are selected. The limitation of this approach is that the lowest-cost materials are not always the most

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economical over the field life - small savings at the project stage can lead to high costs during the operational stage. Life cycle costing adds a third stage to the material selection process which includes the prediction of the cost of operating each material and the addition of this to the purchase price (see Fig. 1). Fig. 2 shows the flow diagram of the various stages that need to be considered during the life cycle costing exercise.

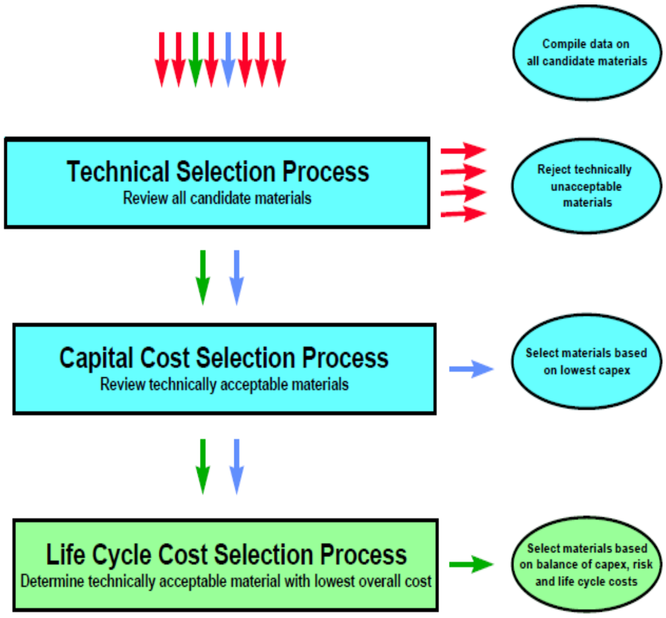

Fig. 1: Material selection process.

Corrosion mitigation measures shall be selected to ensure integrity throughout the intended life of the pipeline system and may include the use of the following items:[1]

- Corrosion-resistant alloy (CRA).
- CRA cladding, overlay, or lining.
- Polymer lining in water service.
- Carbon steel with an added corrosion allowance, by injection or batching of corrosion inhibitor.

For some pipelines, high corrosion rates are predicted due to the high amount of CO_2 present in the well stream, and as such, CRA material will be required for the pipelines. Carbon steel can be used for the pipelines when the product is dry but would need to be CRA material if there is no dehydration facility unless a significant reduction in design life is accepted. However, several options can be considered that may allow the use of carbon steel for the pipeline, such as pressure reduction, pH stabilizers, design life reduction option, subsea cooling spool and production de-rating. However, it is not always easy or viable to implement such options. Furthermore, these options have an element of risk associated with them.

For the wet hydrocarbon option, the corrosion allowance selected is optimized through pre-conceptual and conceptual design as the design process progresses and more information becomes available. Even at the end of the conceptual design phase, there may still be some conservatism in the required corrosion allowance because of some outstanding unknowns in the design. The final opportunity to optimize the corrosion allowance occurs at the very beginning of the detailed design before the long lead items (like the line pipe) are ordered (probably within a month of the beginning of the detailed design). The corrosion allowance generated should be assessed against the following criteria:

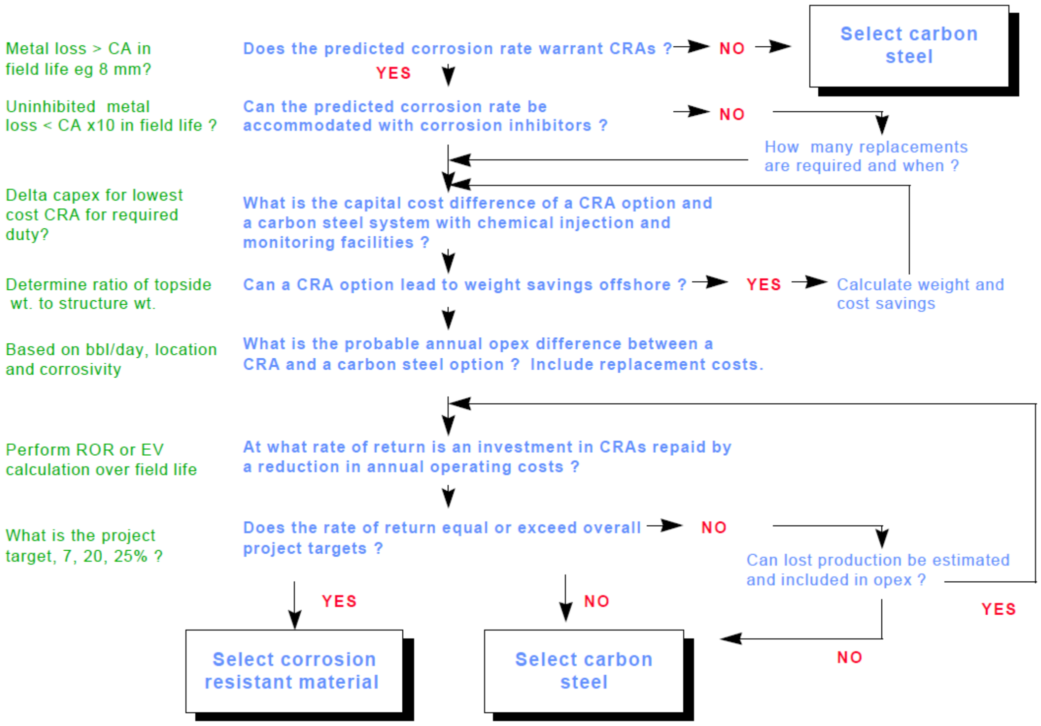

Fig. 2: Decision tree showing considered items during the life cycle cost exercise.

- If the corrosion allowance of the pipeline exceeds 8mm, this should trigger a more detailed review. The 8mm threshold is based on general guidelines accounting for the perceived difficulty of ensuring effective inhibitor penetration to the bottom of corrosion pits, which could compromise long-term integrity. Although there has been no documented testing to determine what this limiting depth would be, this value is advocated here.
- In the conceptual design phase, carry out a pipeline risk-based assessment (RBA) analysis with the selected corrosion allowance and assess the inspection requirements. Determine if an increased corrosion allowance would result in zero or low inspection requirements and check if this is economically attractive. This is not a key activity for piping systems since in-service inspection costs are much lower than for pipelines.
- The corrosion allowance may have to be optimised when making an economic evaluation of carbon steel plus inhibition against the other corrosion control options (*i.e.*, CRA Clad/Mechanically lined pipe). Depending on the constraints of the project, this should either be based on Life Cycle Costs or capital expenditures (CAPEX).

The point at which material selection changes from carbon steel to a CRA is determined by the corrosion rate in conjunction with the design life. For example, carbon steel would be suitable for a corrosion rate of 0.5 mm/y over 10 years when a 5 mm corrosion allowance is added. However, the same corrosion rate over 40 years of design life would require a corrosion allowance of 20 mm which is uneconomical concerning material costs and costs incurred due to offshore girth welding times.

The important factor to consider when contemplating CRA pipelines is the reduction in operating costs that will be achieved. In most cases, CRA pipelines will have negligible operating costs, and it will be reasonable to assume that all the operating costs associated with carbon steel will be saved. This is not always the case and there are several examples of where CRA pipelines that have suffered expensive failures or required repairs. This is generally due to the selection of an inappropriate material that is not resistant to the whole range of operating conditions (*e.g.*, downhole screens that are resistant to production fluids but fail when acidizing solutions are used) or unforeseen operating conditions (such as the high chloride concentrations present on the outside of the duplex separators, leading to cracking of the separator). However, if a CRA is correctly selected with due consideration to the whole range of potential operating conditions, degradation should not be an issue.

The objective of this review paper is to outline the corrosion mechanisms that may arise in the CRA pipelines (*i.e.*, solid CRA, CRA clad and CRA mechanically lined pipelines) and review the resistance of the most common available CRA materials in the pipeline industry. The paper also assesses the impact of the installation methods, lists the precautions necessary during welding and installation of the pipelines, highlights areas of ignorance and prepares a test program to resolve the corrosion unknowns. Furthermore, the paper also highlights the issues that should be considered when evaluating the option of using carbon steel pipes versus CRA-lined pipes.

2. Design and application of CRA

CRAs are specifically engineered for use in environments where corrosion poses a significant threat, such as in oil and gas pipelines, chemical processing plants, and marine structures. The design of CRAs is based on the strategic selection of alloying elements that promote the formation of protective oxide layers on the surface, acting as a barrier against further degradation. This section integrates the design, application, and processing of CRAs with the nuances of their alloy composition, microstructure, and mechanical properties, ensuring optimized performance in harsh environments.

2.1 Alloy composition and corrosion resistance

The effectiveness of CRAs in resisting corrosion is largely dependent on their alloy composition. Essential elements such as chromium, nickel, and molybdenum are crucial for enhancing corrosion resistance. Chromium contributes to the formation of a passive oxide layer that inhibits further oxidation. Nickel stabilizes the austenitic structure of the alloy, particularly under acidic conditions, while molybdenum increases resistance to pitting and crevice corrosion, especially in chloride-rich environments. Key CRAs, such as Alloy 625 and Alloy 825, are commonly applied in sour service environments, particularly in oil and gas pipelines, where they mitigate the risks associated with sulfide stress cracking and hydrogen embrittlement. These alloys find extensive use in subsea pipelines and other critical infrastructure, where their superior resistance to aggressive chemical environments ensures the longevity and safety of the systems.

2.2 Microstructural considerations

The microstructure of CRAs plays a significant role in determining their corrosion resistance. A fine-grained microstructure generally enhances resistance to corrosion by reducing the number of grain boundaries, which can serve as initiation sites for localized corrosion. Duplex stainless steels, composed of both austenitic and ferritic phases, provide enhanced resistance to chloride-induced stress corrosion cracking, making them highly suitable for marine and offshore applications. The balance between these phases is critical during the alloy production process. Careful control of overheating treatment, and mechanical processing ensures that undesirable phases, which might impair corrosion resistance, are avoided. The result is a stable, corrosion-resistant structure that performs reliably in highly corrosive environments.

3. Processing and heat treatment of CRAs

The processing and heat treatment of CRAs is essential for optimizing their mechanical properties and corrosion resistance, ensuring that these alloys can withstand aggressive environments over extended periods. Both CRA plates and coils undergo specialized processing techniques, which are critical for refining their microstructure, enhancing mechanical performance, and ensuring long-term durability.

3.1 Thermomechanical processing

Thermomechanical processing combines mechanical deformation with controlled heat treatment to enhance the strength and corrosion resistance of CRAs. This process ensures that both CRA plates and coils exhibit uniform grain distribution, which is key to maintaining the material's mechanical integrity and corrosion resistance. The application of thermomechanical processing dissolves harmful precipitates and refines the microstructure, improving the material's ability to form a stable, protective, passive layer. For CRA plates, thermomechanical processing is particularly important in increasing structural integrity, which is necessary for applications such as subsea pipelines and pressure vessels. In the case of CRA coils, the process ensures that the material remains flexible and resistant to deformation during forming operations while maintaining the desired corrosion-resistant properties.

3.2 Heat treatment techniques for CRA plates and coils

Heat treatment plays a vital role in stabilizing the microstructure and enhancing the corrosion resistance of CRAs. One of the most commonly used heat treatment techniques is annealing, where the alloy is heated to a specific temperature and then slowly cooled to relieve internal stresses and dissolve unwanted precipitates. This process is crucial in ensuring a uniform microstructure free from corrosion-prone phases along grain boundaries.

- **CRA Plates**: Heat treatment for plates focuses on improving ductility, reducing internal stresses, and refining the grain structure. This enhances the mechanical strength required for high-pressure applications, such as pipelines, where structural integrity is paramount.
- **CRA Coils**: Coils, which are thinner and more flexible than plates, undergo heat treatment to maintain flexibility during further fabrication while preserving their corrosion-resistant properties. The process ensures that coils can withstand forming and bending operations without compromising their mechanical or corrosion-resistant performance.

The heat treatment process must be carefully controlled to prevent the formation of secondary phases that could lead to galvanic corrosion. Time and temperature control during heat treatment are critical to achieving the desired alloy properties.

3.3 Surface finishing for enhanced corrosion resistance

Surface finishing techniques, such as polishing and shot peening, are applied to both CRA plates and coils to improve surface quality and enhance corrosion resistance. Polishing helps reduce surface roughness and seal microcracks, which could otherwise serve as initiation points for corrosion. A smooth, polished surface also ensures that the protective oxide layer remains intact, reducing the risk of pitting and crevice corrosion. Shot peening induces compressive stresses on the surface of the material, which significantly improves its resistance to stress corrosion cracking. This is particularly important for components exposed to high-pressure environments, such as subsea pipelines, where corrosion fatigue is a major concern.

4. Duplex stainless steels

Duplex stainless steels (DSSs) consist of a mixed microstructure of austenitic and ferritic phases, which provides a unique combination of strength and corrosion resistance. This dual-phase microstructure enhances resistance to chloride-induced stress corrosion cracking (SCC), a common concern in marine and offshore applications where chlorides are prevalent. The structure, properties, and applications of DSSs can be briefly summarized as follows:

- **Structure:** The balanced microstructure of DSSs results in higher yield strength compared to conventional austenitic stainless steels. This allows for the use of thinner wall sections, reducing material costs without compromising mechanical performance. The presence of ferrite improves resistance to SCC, while the austenite phase enhances toughness and ductility.
- **Properties:** DSSs are highly resistant to pitting and crevice corrosion, particularly in chloride-rich environments. This makes them ideal for applications involving seawater, desalination plants, and offshore oil platforms.
- **Applications:** DSSs are widely used in subsea pipelines, risers, and processing equipment in oil and gas production. They offer a cost-effective alternative to higher-priced CRAs, providing a balance of strength and corrosion resistance.

5. Super duplex stainless steels

Super duplex stainless steels (SDSSs) offer greater strength and corrosion resistance than standard duplex grades due to their higher chromium, molybdenum, and nitrogen content. These elements significantly improve resistance to pitting and crevice corrosion in highly aggressive environments. The structure, applications, and limitations of SDSSs can be briefly summarized as follows:

- **Structure**: SDSSs have a similar dual-phase microstructure to standard duplex steels but with a higher proportion of alloying elements. This composition results in enhanced resistance to SCC and better mechanical performance under high-pressure and high-temperature conditions.
- **Applications**: SDSSs are used in deepwater oil and gas production, particularly in riser systems and flowlines, where mechanical strength and corrosion resistance are critical. They are also employed in chemical processing plants, desalination systems, and marine structures exposed to harsh environmental conditions.
- **Limitations**: While SDSSs perform well in most

environments, their use is limited at high temperatures, where phase instability can lead to reduced corrosion resistance and mechanical performance.

6. Comparison and selection criteria of CRA, duplex, and super duplex alloys

Selecting the appropriate material for a specific application involves balancing factors such as corrosion resistance, mechanical strength, and cost. While all three materials–CRA, duplex, and super duplex alloys–offer excellent corrosion resistance, the decision on which to use depends on some specific environmental conditions and mechanical requirements, as follows:

Cost vs performance: Duplex and Super Duplex stainless steels (*e.g.*, 22%Cr, 25%Cr) are generally more cost-effective than high-end nickel-based CRAs while still providing excellent corrosion resistance, particularly in seawater and chloride-rich environments. However, nickel-based CRAs, such as Incoloy 825 and Inconel 625, are preferred for environments requiring maximum corrosion resistance, especially in sour service applications where high H_2S levels, elevated temperatures, and acidic conditions demand superior material performance.

Operating conditions: Super Duplex stainless steels are well-suited for extreme conditions involving high chlorides, high pressures, and elevated temperatures, making them ideal for offshore and subsea applications. Duplex steels provide a more cost-effective solution for moderate environments with lower chloride exposure and temperature requirements. Nickel-based CRAs, on the other hand, are used in highly corrosive environments where maximum corrosion resistance is essential, such as in sour gas wells, aggressive chemical processing conditions, and environments with severe localized corrosion risks.

7. Possible corrosion mechanisms

The mechanisms of corrosion that could occur in the CRA clad/lined subsea pipelines are:

- General corrosion.
- Pitting corrosion.
- Crevice corrosion.
- Chloride stress corrosion cracking.
- Sulphide stress cracking.
- Corrosion fatigue.
- Hydrogen-induced stress cracking.
- Sensitization.
- Microbiological corrosion.
- Corrosion by precipitated free sulphur.

7.1 General corrosion

General corrosion would only be significant for carbon manganese steel. The martensitic stainless steel may show some slight material loss in acidic solutions, and it is not uncommon to allow for a small corrosion to accommodate this metal loss. The higher alloyed materials do not show significant general metal loss.

7.2 Pitting corrosion

Pitting corrosion can occur in all kinds of metals. The pitting behavior of carbon steel is well reported though pitting rates and is very difficult to quantify. Pitting often initiates defects in the metal surface. With the CRA pipes, the risk of pitting is loosely related to the pitting resistance number (PREN) defined as follows:

$$\text{PREN} = \text{Cr\%} + 3.3\,(\text{Mo\%} + 0.5\ \text{W\%}) + 16\ \text{N\%} \qquad (1)$$

where PERN = Pitting Resistance Number, Cr = Chromium, Mo = Molybdenum, W = Tungsten, and N = Nitrogen.

The CRA materials exhibit pitting corrosion at the areas where the passive oxide films break down and fail to reform. Pitting may initiate at areas of damage to the surface film, such as damage that can occur during fabrication of the pipe or installation, for example, the formation of excessive oxide tint at weldments. The most common trigger for initiating pitting is the chloride ion. Each generic CRA has a tolerance to chloride that is related to the operating temperature, and molybdenum is particularly important because of the multiplier and the impact of molybdenum content on pitting in chloride solutions is shown in Fig. 3.

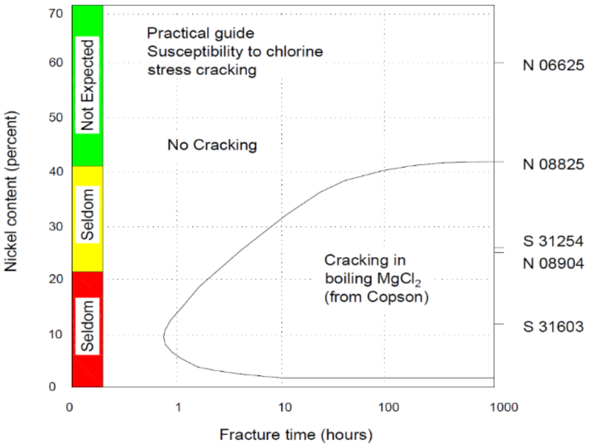

Fig. 3: Nickel content and risk of chloride stress corrosion cracking from stress-corrosion cracking of Nickel-base alloy weldments (Nickel Development Institute, Int. Inst. Welding, Montreal, 1990).

Table 1: Pitting and crevice corrosion of CRA pipes.

Alloy	PREN	Critical temperature* (ºC)	
		Pitting	Crevice
Martensitic stainless steel	19	0	0
Super martensitic stainless steel	21	2	0
Type 316L	26	20	0
Alloy 825	26	30	2
Type 317L	31	40	3
Duplex stainless steel 2205	35	52	16
904L	37	60	18
Super duplex stainless steel 2507	42	84	41
254 SMO	43	90	41
Al6-XN	45	78	45
Alloy 625	51	85	40
C-276	66	85	50

PREN = Pitting resistance number; *1M sodium chloride test solution.

The pitting temperatures of the candidate materials are listed in Table 1. These values are derived from standard tests using boiling sodium chloride solutions. At the operational temperature, the most common CRA materials would be operating above their critical pitting temperatures. However, though pitting is possible, it does not necessarily occur. When the flow rate is adequate pitting may not occur unless areas of significant damage are present. One important issue, however, is the change in microstructure that occurs in the heat-affected zone (HAZ). This change is usually a growth of the grains and potential deposition of chromium carbide at grain boundaries, insufficient to result in sensitization but sufficient to alter the critical pitting temperature.[1-6] The critical pitting temperature (CPT) for base metal and weldments for a range of CRAs is given in Table 2. The reduced CPT is critical for the solid CRA pipes where the weldment would be closely matched to the parent material. The clad pipe would be welded with consumables of enhanced metallurgy that provide a higher CPT, for example, 904L, 254-SMO and alloy 825, which is welded with alloy 625. In one case, failure of a CRA material has resulted from the unexpected local concentration of chlorides because of the evaporation of water.[7]

Table 2: Critical pitting temperatures of welds in CRA pipes.

Grade*	UNS	Critical Pitting Temperature CPT (ºC) in 6% $FeCl_3$		SCC of base metal time to failure (hours) NaCl at 200 ºC 50% YS
		Base metal	Weld metal	
SAF 2304	S32304	20	10	350
Type 2205	S31803	35	25	350
SAF 2507	S32750	70	45	> 500
Type 316L	S31603	5	2	100
904L	N08904	40	25	> 500
254 SMO	S31254	70	45	> 500

7.3 Crevice corrosion

Crevice corrosion is like pitting and can occur on carbon-manganese steels, it is a particularly serious issue for most CRA pipes. Crevice corrosion occurs when a narrow gap is present between an inert material and the CRA surface. Typical crevice situations exist beneath gaskets and adherent scales and deposits. In almost all cases, crevice corrosion requires the presence of oxygen and chloride ions. As for pitting, there is a critical temperature below which crevice corrosion does not occur. The critical crevice temperatures for the candidate materials are listed in Table 2. Most of the candidate materials are susceptible to crevice corrosion; however, crevice corrosion results in an increase in the dimension of the crevice, and after a period, the corrosion ceases. Each CRA pipe has a characteristic crevice geometry that is related loosely to the pitting resistance number. If the

Table 3: Chloride stress corrosion cracking of CRA pipes.

Alloy	CSCC ºC	Threshold % YS	Pass/Fail in boiling solution		
			$MgCl_2$	$LiCl_2$	NaCl
Martensitic SS	---	---	P	P	P
Super martensitic SS	---	---	P	P	P
Duplex stainless steel	150	30	F	P	P
Super duplex SS	> 200	75	P	P	P
Type 316L SS	60	10	F	F	F
Type 317L SS	70	10	F	F	F
904L SS	120	75	F	F/P	P
254-SMO SS	> 200	90	F	P	P
AL6-XN SS	121	90	F/P	P	P
Alloy 825	250	---	P	P	P
Alloy 625	---	---	P	P	P

PREN = Pitting Resistance Number; F = Fail and P = Pass for 1,000 hr test.

crevice is narrower than the critical crevice dimension, then crevice corrosion may initiate. For example, the critical crevice dimension for type 316 L is 0.4 mm whilst for alloy 904L, the crevice dimension is 0.15 mm. Crevices must not be formed at the girth welds by lack of penetration or side wall fusion or overlap. Provided welds are defect-free and deposits and scales are prevented crevice corrosion should be avoided.

7.4 Chloride stress corrosion cracking

Chloride stress corrosion cracking (CSCC) can occur in austenitic and duplex stainless steels when the material is stressed, chloride and oxygen are present, and the temperature is above a critical value. The data in the literature do not identify a threshold oxygen level below which cracking does not occur. However, the time taken to initiate cracking is extended at lower oxygen levels. Studies of failures in oil and gas facilities indicated that internally initiated cracking had occurred in extremely low oxygen environments; the levels were estimated to be a few parts per billion or less. Factors that appeared to be involved in the internal CSCC failures in oil field equipment included the unexpected deposition of chloride deposits on internal walls, downstream of chokes; incorrect specification of the operating conditions leading to incorrect materials selection; and an assumption that there would be no oxygen present.[8] The first stage of cracking is pitting which is thought to initiate at and follow grain boundaries where chromium carbide deposits have formed and depleted the chromium. Residual and applied stress will always be present and, once above the critical temperature, the risk of cracking of a CRA will depend on the oxygen and chloride concentrations. The critical temperatures for generic CRAs are given in Table 3. An alternative method of ranking the resistance of a material to CSCC is to drip saline water onto a heated strip of the material that is stressed progressively in 20% increments. Eventually, the material develops a crack and fails. This test is useful in that it indicates the applied stress at which cracking occurs. Data for the candidate materials is given in Table 4.

Table 4: Saline drop test data for CRA pipes.

Alloy	Minimum stress for CSCC (MPa)	% of typical YS (0.2%)	Time to Failure – Test 1 (hrs)	Time to Failure – Test 2 (hrs)
2205	227	50	360	>500
2507	372	90	415	>500
904L	193	90	230	348
254-SMO	> 221	> 90	>500	>500

A dilute sodium chloride solution is slowly dripped onto an electrically heated specimen that is simultaneously subjected to tensile stress. The applied stresses are gradually increased in increments of 20% until they are 90% of the material's yield strength at 200 °C. The test is run for up to 500 hours and measures the minimum stress required for failure. The results given are for duplicate tests.

Martensitic stainless-steel pit but are immune to CSCC. Duplex stainless steels show a high resistance to CSCC partly because of their mixed ferritic-austenitic structures though the basic reason for their resistance is largely unresolved.[9] For the austenitic alloys, an increase in nickel content reduces the risk of CSCC and at 24% nickel, the material behaviour is significantly altered such that CSCC seldom occurs. The 904L and 254-SMO contain 24%. Nickel and high nickel alloys that contain more than 42% Ni are essentially immune. The effect of nickel content on the risk of CSCC is illustrated in Fig. 4. Molybdenum content is also important, see Fig. 4. The sensitivities of alloys to CSCC are evaluated by extreme tests using boiling halide solutions, typically magnesium, lithium and sodium chlorides. Though these tests have a role in ranking the alloys they have less value for practical applications. They do however give some confidence in materials selection if the test temperatures are sufficiently high

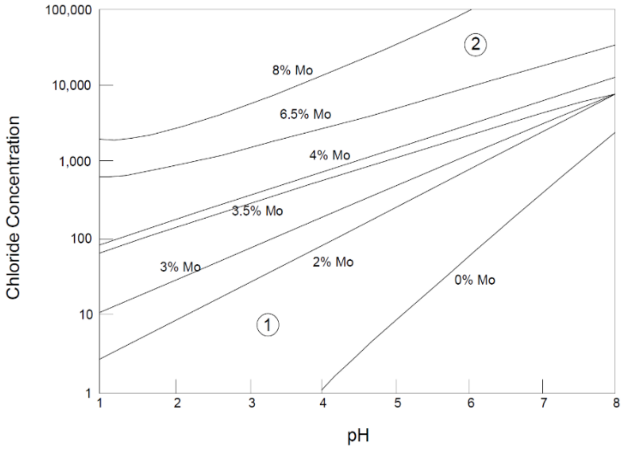

Fig. 4: Pitting corrosion as a function of chloride, pH, and molybdenum content. Pitting resistance above the line for chloride and pH. Initial conditions with acid-condensed water (1) and final conditions with less acidic saline water (2)

7.5 Sulphide stress cracking

Sulphide stress cracking (SSC) can occur in many metals and occurs when a susceptible material is exposed to water containing hydrogen sulphide whilst subject to a relatively high static load. Once cracking initiates, the atomic hydrogen generated by cathodic corrosion reactions migrates to the vicinity of the crack tip; the hydrogen migrates towards the high-stress areas. The risk of SSC is highest in the temperature range of 20-120 °C. At low temperatures, inadequate atomic hydrogen migrates through the metal to cause embrittlement whilst at high-temperature hydrogen rapidly diffuses out of the metal and does not accumulate. The risk of SSC is identified from the pH of the water and the partial pressure of hydrogen sulphide. NACE MR-0175/ISO 15156 is the principal reference document.[10] If SSC is possible then it is avoided by ensuring that the strength of the material is below a critical value specific to material composition. The strength is generally identified by hardness testing. NACE MR-0175/ISO 15156 defines sour service related to water pH and the partial pressure of hydrogen sulphide (refer to Table 5).[10]

7.6 Corrosion fatigue

Metals that are exposed to a corrosive environment do not exhibit a fatigue limit. Surface films that would reduce or prevent corrosion are fractured by the cyclic tensile forces so that fresh metal is exposed; over time the enhanced pits that are created are converted to fatigue cracks. Simulation studies of failures indicate that the development of the initial pit is 60% of the time to failure whilst representing less than 10% of the final failure size.[11-13] The prevention or inhibition of pitting is critical in preventing corrosion fatigue. The initiation of internal pipeline corrosion fatigue may be delayed using corrosion inhibition but is generally not prevented. For external pipeline surfaces the fatigue limit is recovered if cathodic protection is used to prevent corrosion. Some CRA materials are susceptible to corrosion fatigue and the risk appears to be related to the pitting propensity of the material, essentially related to the PREN. There is a gradual decline in the operating pressure of the pipelines as the reservoir pressure reduces to 35 bar at the end of field life. Some shutdowns will require blowdown to low pressure, and it is estimated that shutdowns may occur up to 14 times per year. There may be several minor pressure transient events. During and after blowdown the temperature of the flowline will fall resulting in contraction of the pipeline and/or differential contraction of the cladding/liner. Though the frequency of cyclic loading is low the amplitude will be high and possibly close to or exceeding yield (the Erskine pipeline is understood to have failed because of pressure and temperature cycling). The weldments are the locations where the most damage would be expected because of this low cycle high amplitude fatigue loading because the welds are anchored to the steel pipe. Defects in welds may develop or coalesce resulting in the formation of critical size defects. The differential expansion of CRA material compared to carbon steel may also be significant. As temperature increases the CRA will expand more than carbon steel resulting in a compressive force in the liner, and this is discussed in Section 4.1. CRA materials have a higher expansion coefficient than carbon steel (refer to Table 6).

Table 5: Sulphide stress cracking of CRA pipes (extracted from NACE MR-0175/ISO 15156).[10]

Alloy	PP H2S (kPa)	Other factors	Limiting HRC
Carbon manganese steel	0.345	---	22
Martensitic stainless steel	10	pH ≥ 3.5	22
Super martensitic SS	10	pH ≥ 3.5	28
Type 316L	100	T < 60; no S°	22
Type 317L	100	T < 60; no S°	22
Duplex stainless steel	10	T < 232	25
904L PREN > 40	100	Cl⁻ < 5000; T < 171	22
Super duplex stainless steel	20	Cl⁻ < 5000; T < 232	25
254-SMO	20	T < 232	25
Al6-XN	20	T < 232	25
Alloy 825	N/A	T < 171	35
Alloy 625	N/A	T < 171	35

Key: T = temperature °C; Cl⁻ = chloride (ppm); S° = free sulphur; N/A = not applicable.

Table 6: Linear thermal expansion coefficients of CRA pipes.

Material	Units	Value
Carbon steel	$\times10^{-6}/^{o}C$	6.3
2205	$\times10^{-6}/^{o}C$	13.2
904L	$\times10^{-6}/^{o}C$	16.0
2507	$\times10^{-6}/^{o}C$	13.0
254-SMO	$\times10^{-6}/^{o}C$	16.0
Alloy 825	$\times10^{-6}/^{o}C$	14.0
Alloy 625	$\times10^{-6}/^{o}C$	12.8

7.7 Hydrogen-induced stress cracking

Hydrogen-induced stress cracking (HISC) was originally termed hydrogen embrittlement and occurs after a metal has absorbed atomic hydrogen. Other influences are local plastic strain (particularly tri-axial stresses). The hydrogen behaves as an alloying element and the ductility of the metal is severely reduced such that a shock load or impact may result in a brittle fracture of the metal rather than a ductile deformation. The atomic hydrogen normally arises from corrosion reactions though for CRA materials it is more common for the hydrogen to arise from the cathodic protection system. Austenitic and high nickel alloys are immune. Martensitic and duplex stainless steels are susceptible to the hydrogen generated by the external cathodic protection system. The risk reduces as the temperature increases but pipelines may cool and consequently, the cathodic protection (CP) system must be designed to avoid the risk of HISC. DNV RP F112 and NORSOK M-WA-0 are the most commonly used recommended practices to avoid the risk of hydrogen embrittlement of the duplex stainless steels.[14-18] The potential of the duplex steels must not be more negative than -850 mV (SSCE).

7.8 Sensitization

Sensitization is caused by the precipitation of chromium carbides along the prior austenite grain boundaries during welding. The carbides reduce the chromium concentration along narrow zones running along the grain boundaries. Less chromium is available to reform the protective oxide films and preferential corrosion can occur along the grain boundaries. High nickel content nickel alloys also develop unfavourable phases along the grain boundaries, but these are less likely to be continuous and intergranular separation is far less likely to occur.

7.9 Microbiological corrosion

Microbiological corrosion can occur inside and outside pipelines because of the activity of sulphate-reducing bacteria (SRB). These organisms are anaerobic and oxidize organic material (usually fatty acids) using the oxygen in the sulphate radical. They are common in seawater injection pipelines and oil pipelines, after the breakthrough of seawater from the seawater injection used for pressurization of the reservoir. The SRB have limited tolerance to low pH; water in gas condensate pipeline systems is generally too acidic despite the presence of a suitable food source and sulphate. Towards the end of field life, the pH may be in the range that is tolerable to some strains of SRB sulphate and fatty acids will be present from the formation water. At the SRA platform, the temperature will be moderate, and it is faintly possible that bacterial growth could occur if the pipeline is contaminated by a maintenance operation. Most metals and alloys can be corroded by active growth of SRB. Materials believed to be inert are titanium alloys and Ni-Cr-Mo alloys containing 6% or more molybdenum.[19,20]

7.10 Corrosion by precipitated free sulphur

Wet sulphur is known to be corrosive to carbon steel as it can generate a pH below 2. Few studies have been done on the effect of free sulphur on CRA materials.[21] For corrosion to occur the sulphur must be in direct contact with the CRA. If the sulphur can be kept in suspension it does not appear to cause corrosion. Chromium affords protection in the absence of chloride but the combination of wet sulphur with chloride can be corrosive. The literature reports the combination of 10,000 ppm chloride with 1,000 ppm sulphur at 66 °C resulted in 0.2 mm pitting of alloy 825 and type 2550 (similar to SDSS 2507) after one month of exposure. An increase in the chloride content to 50,000 ppm increased pitting depth to 0.6 mm. Increasing the temperature from 60 to 93 °C at 10,000 ppm chloride did not significantly increase the pitting depth. This would suggest that sulphur attack results after pitting, caused by chloride ion, has occurred. The combination of chloride and sulphur may induce SSC though only at a high temperature above ~150 °C. Alloy 825 appears to be susceptible to SSC but alloy 625 is resistant. This would suggest that other alloys with lower nickel content may also be susceptible. Generally, the effect of sulphur on the risk of SSC of CRAs appears to be related to the molybdenum content. This would suggest that the attack is related to the extent of pitting by chloride ions.

7.11 Selection of corrosion-resistant alloys

Corrosion-resistant alloys (CRAs) are critical materials used in upstream oil and gas operations to combat corrosion, particularly in environments containing hydrogen sulfide (H_2S). In sour service, where the risk of sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), and stress corrosion cracking (SCC) is high, the selection of appropriate CRA materials is crucial to ensure safe and long-lasting operation. The ISO 15156 standard and company-specific guidelines, provide a framework for the selection, qualification, and testing of these materials.

8. Selection of corrosion-resistant alloys

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8.1 Factors influencing CRA selection

When selecting CRAs for sour service applications, it is essential to consider several environmental, mechanical, and operational factors. These factors not only dictate the choice of material but also influence the long-term integrity of the equipment.

- **H_2S partial pressure**: The level of H_2S in the environment is a critical determinant of alloy selection. Higher H_2S partial pressures increase the likelihood of sulfide stress cracking (SSC). Materials selected for such environments must be qualified to resist SSC, particularly in environments where H_2S exceeds the threshold set by ISO 15156-3.
- **Temperature and pH**: Elevated temperatures and acidic environments accelerate corrosion mechanisms such as stress corrosion cracking (SCC) and hydrogen embrittlement. The ISO 15156 standard highlights specific operating limits for various CRAs, defining acceptable service temperatures and pH ranges to minimize these risks.
- **Hardness and mechanical properties**: The hardness of

the material plays a significant role in its susceptibility to cracking. ISO 15156 specifies maximum allowable hardness levels for various CRAs to ensure that the material does not become brittle under stress or in the presence of H_2S. For example, nickel-based alloys often have stricter hardness requirements to prevent hydrogen embrittlement.

- **Fabrication and welding requirements**: The performance of CRAs can be affected by the processes used during fabrication, such as welding and heat treatment. Special care must be taken during these processes to ensure that the material's corrosion-resistant properties are not compromised. For example, ISO 15156 specifies guidelines for welding procedures to avoid issues like sensitization, which can increase susceptibility to localized corrosion.

8.2 Classes of corrosion-resistant alloys

Corrosion-resistant alloys are categorized based on their chemical composition and their ability to resist various forms of corrosion in sour environments. These categories include austenitic stainless steels, duplex stainless steels, and nickel-based alloys, among others.

- **Austenitic stainless steels**: These CRAs, containing high amounts of nickel and chromium, are widely used due to their resistance to CSCC and pitting corrosion. Common austenitic stainless steels include 316L and 317L, which are often used in environments with moderate chloride concentrations. These alloys are also preferred for applications where the operating temperatures remain below 60 °C and where partial H_2S pressures do not exceed the limits specified by ISO 15156-3.
- **Highly alloyed austenitic stainless steels**: In more aggressive environments, highly alloyed austenitic stainless steels such as Alloy 904L are used. These alloys contain higher levels of molybdenum and nitrogen, which improve their pitting and crevice corrosion resistance, making them suitable for harsher sour service conditions.
- **Duplex stainless steels**: Duplex stainless steels, such as 22% Cr and 25% Cr grades, combine the best properties of austenitic and ferritic steels. Their dual-phase microstructure provides excellent resistance to stress corrosion cracking (SCC), pitting, and crevice corrosion. Duplex steels are widely used in subsea pipelines and offshore platforms due to their strength and durability in chloride-rich, H_2S-containing environments. Additionally, their mechanical properties allow them to be used at higher pressures, making them suitable for deep-water applications.
- **Nickel-based alloys**: Nickel-based alloys, such as Alloy 625 and Alloy 825, offer superior resistance to a broad spectrum of corrosion mechanisms, including sulfide stress cracking (SSC), hydrogen embrittlement, and pitting corrosion. These alloys are particularly effective in environments where both high H_2S concentrations and high temperatures are present. The high nickel content ensures that these materials maintain their mechanical properties and corrosion resistance, even in the most aggressive environments.

8.3 Application in sour service

In sour service, materials must withstand a range of aggressive environmental conditions, including exposure to H_2S, chlorides, and high temperatures. CRAs are selected based on their ability to resist SSC, HIC, and other forms of environmental cracking.

- **Nickel-based alloys in high-temperature applications:** Nickel-based alloys like Alloy 625 are favored for their robustness in high-pressure, high-temperature (HPHT) environments, where both H_2S concentrations and chloride levels are elevated. These alloys are typically used in critical components such as wellheads, risers, and downhole tubulars, where material failure could result in catastrophic consequences.
- **Duplex steels in subsea applications**: Duplex stainless steels are widely used in subsea applications where chloride exposure is significant, such as in seawater injection systems and flowlines. Their high strength-to-weight ratio and corrosion resistance make them ideal for deep-water pipelines.
- **Austenitic stainless steels in process piping**: For onshore and offshore process piping where chloride exposure is moderate, austenitic stainless steels such as 316L are frequently used. Their ability to withstand localized corrosion, combined with their ease of fabrication, makes them cost-effective solutions for less aggressive environments.

8.4 Material qualification and testing

ISO 15156-3 emphasizes the importance of rigorous material qualification before deployment in sour service. Materials intended for H_2S service are subjected to stringent laboratory tests, including:

- **SSC and SCC resistance testing**: NACE TM0177 and TM0284 test methods are widely used to evaluate the susceptibility of materials to sulfide stress cracking and stress corrosion cracking. These tests help in determining the maximum allowable hardness for materials in specific sour service applications.
- **Hydrogen embrittlement resistance**: Nickel-based alloys, which are prone to hydrogen embrittlement, undergo hydrogen permeability testing to assess their ability to resist hydrogen-induced cracking in H_2S environments. Test results guide the selection of materials based on their hardness and environmental compatibility.
- **Field performance and validation**: In addition to laboratory testing, field performance data is crucial in validating the long-term resistance of CRAs to environmental cracking. Materials are often deployed in pilot projects or small-scale field trials to assess their performance under actual operating conditions.

Fig. 5 presents the selection and testing process for CRAs in sour service environments. The figure outlines the following stages: starting with material selection based on environmental factors such as H_2S partial pressure, temperature, and pH, the process moves through the classification of CRAs into austenitic, duplex, and nickel-based alloys. The chart then demonstrates the application of these materials in sour service conditions, followed by material qualification testing, including SSC, SCC, and hydrogen embrittlement testing. The final step involves field performance validation through small-scale trials to confirm the material's long-term resistance to environmental cracking before deployment.

9. General requirements for CRA alloy qualification

The qualification of CRAs is essential to ensure the reliability and integrity of pipelines and components, especially in challenging environments such as those containing hydrogen sulfide (H_2S) in oil and gas production. DNV-ST-F101 (2021) and ISO 15156-3 (2020) outline stringent guidelines for the selection, testing, and qualification of CRAs to mitigate the risks of material failure from cracking and corrosion.

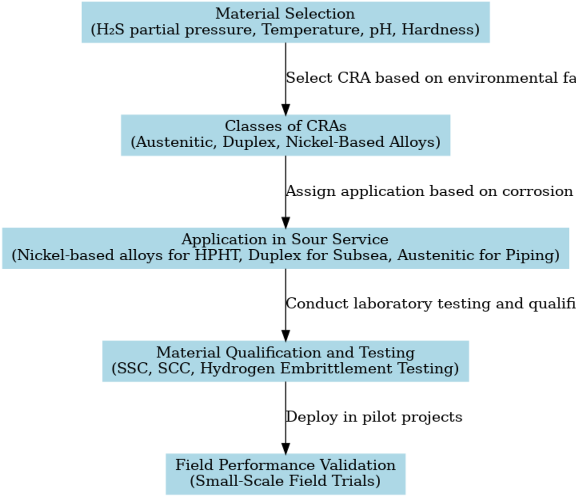

Fig. 5: Flowchart for CRA selection and testing.

9.1 Material selection criteria

In DNV-ST-F101, Section 6.2 highlights the critical aspects of material selection, emphasizing mechanical performance, corrosion resistance, and toughness requirements. For CRAs, these requirements are particularly stringent when exposed to sour service (H_2S environments). Materials must be selected based on their ability to withstand combined mechanical and environmental stresses, with specific attention to sour service, as outlined in Section 6.4 of DNV-ST-F101. ISO 15156-3 (Section 6) addresses material selection specifically for H_2S environments, setting forth criteria for preventing SSC and SCC. The standard includes tables with acceptable limits for different alloy groups and introduces the concept of the pitting resistance equivalent number (PREN) to evaluate susceptibility to pitting corrosion. Materials such as super duplex stainless steels and nickel alloys (*e.g.*, UNS N06625) are recommended for environments with high chloride content and elevated temperatures.

9.2 Welding and fabrication considerations

According to DNV-ST-F101, Section 7.4 focuses on the qualification of welding procedures for CRAs, emphasizing that the welding process must not compromise the material's corrosion resistance or mechanical properties. Post-weld heat treatment (PWHT) may be required, particularly for duplex and super duplex stainless steels, to maintain their microstructure and mechanical integrity. ISO 15156-3 (Section 6.2.2) elaborates on the evaluation of welds for sour service, specifying that welds must meet hardness limits to avoid SSC. Weld qualification tests are required to simulate the most severe service conditions anticipated during the pipeline's operational life. Special attention is given to hydrogen-induced cracking (HIC) and hydrogen embrittlement in weld zones.

9.3 Testing Requirements

DNV-ST-F101, in Appendix B, details the testing protocols necessary for CRA qualification, including tensile testing, Charpy impact testing, and fracture toughness evaluations. These tests ensure that the material can withstand both operational loads and environmental stresses (DNV-ST-F101-2021). ISO 15156-3 (Annex B) specifies the laboratory tests required for CRAs in H2S service, such as those outlined in NACE TM0177 and TM0284, which assess the material's resistance to SSC and SCC under simulated service conditions. These tests are crucial for ensuring the material's long-term performance in H2S-containing environments, as outlined in Section 6 of ISO 15156-3.

9.4 Documentation and Traceability

Both DNV-ST-F101 (Section 12) and ISO 15156-3 (Section 7) emphasize the importance of documentation and traceability throughout the material qualification process. Full traceability of CRA materials, including heat numbers, chemical compositions, and mechanical and corrosion test results, is mandatory. The documentation ensures that materials meet the specified requirements and can be traced back to their origins in case of future inspections or audits.

10. Solid CRA materials

10.1 General comments

API 5LC is the principal document related to CRA pipelines. The CRA will need to be resistant to corrosion and chloride stress cracking in aerated seawater. As cathodic protection would be applied the material must also be immune to cathodic embrittlement or the CP potential restricted to prevent HISC. If used as the pipe in the pipe, then external corrosion by aerated seawater would be avoided. The available materials that tolerate contact with seawater are weldable super martensitic 13 chrome, duplex and super duplex stainless steels, and alloy 625. DSS and SDSS both show a reduction in yield strength at elevated temperatures. Alloys type 316L, 904L, and alloy 825 are not suitable for use in solid CRA forms because of their low yield strength. Alloys 316L

Table 7: Weldable 13 Chrome steel - Composition.

Cr	Ni	Mo	N	Fe	PREN
12 – 14	3.5 – 4.5	0.3 – 0.7	---	Remainder	15 – 19
12 – 14	5 – 6	2.5 – 3.5	---	Remainder	22 – 25

Table 8: Weldable 13 Chrome steel - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	HISC	MIC	Sulphur
XXX	XXX	XXX	A	R	uncertain	XXX	X	X

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 9: Weldable 13 Chrome steel - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	HISC	MIC	Sulphur
0.05 m/y	T > 2 ºC	T > 0 ºC	HRC < 22/28	---	---	-850 mV SSCE	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

and 904L are also susceptible to chloride stress corrosion cracking in aerated seawater at elevated temperatures in the absence of cathodic protection.

The solid CRAs are susceptible to HISC because of hydrogen charging from the CP system. Though the guidelines in DNV-RP-F112 are principally concerned with duplex stainless steels, it is also relevant to weldable 13Cr material. It is recommended that the potential is restricted to -850 mV (SSCE), which is normally achieved by including a resistor in the connection of the anode to the pipeline and this approach works for pipelines that operate at modest temperatures. However, for pipelines operating at high temperatures, a large CP protection current is required, and consequently, a large surface area of anode material must be provided. At shut down the pipeline will cool, and the current density required for protection will reduce, but the anodes will remain able to supply the high current density. A fixed resistor would be unable to control the potential of the material, which would be reduced to close to the anode potential. Specialized current limiting devices, Schottky barrier rectifiers, need to be installed between the anode and the pipeline.[22,23]

An alternative approach that may be worth considering is to supply the cathodic protection current from remote anodes sited on anode rafts. Because the anodes are remote and at ambient temperature, they will operate at higher efficiency than anodes directly attached as bracelets to the pipelines. A well-designed anode raft can protect up to 4 km of pipeline. The use of rafts would permit more reliable control of the potential of the pipelines. If the solid CRA material is enclosed within a steel pipe in a pipe-in-pipe configuration, the external corrosion issues are avoided.

10.2 Weldable 13 Chrome Steels (Lean and High Alloy UNS 41425)

Tables 7 to 9 present the chemical compositions of Weldable 13 Chrome as well as the corrosion mechanisms that may occur in Weldable 13 Chrome.

The weldable 13Cr steels may be ‘lean’ (4Ni0.6Mo) or high alloy (5.5Ni3Mo); for this service the presence of salinity indicates that the high alloy variety would be required. The girth welds would be made using super duplex filler. The high alloy 13Cr is regarded as an alternative to duplex stainless-steel type 2205 provided the fluids are not too corrosive. Weldable 13Cr pipe material is approximately half the price of DSS type 2205. Weldable 13Cr has a high yield strength but does show relaxation of tensile properties at high temperatures. For example, trials indicated a de-rating of about 9 % for a temperature rise from 20 °C to 200 °C. Weldable 13Cr may show general corrosion though this will be irregular and localized. A corrosion rate of 0.05 mm/year is often assumed to occur and a small corrosion allowance is provided.

The PREN is around 19, which means limited resistance to pitting and crevice corrosion. Provided the strength is restricted it is tolerant to a low concentration of hydrogen sulphide. Concerning internal corrosion, the material would be borderline for the condensed gas service as the pH could fall below 3.5 depending on the temperature of the fluids but the material may be suitable for service in the high chloride formation water because of the shift in pH as chloride content rises.[24-26] The presence of oxygen, however, would result in significant pitting corrosion. The mono-ethylene glycol (MEG) may reduce the rate of corrosion but probably not sufficiently. The PREN of the material is too low to prevent external corrosion without the application of cathodic protection. A failure of the CP system would result in severe external pitting. Weldable 13Cr is susceptible to HISC and anode output would need to be controlled by an active resistive device. Weldable 13Cr does not suffer chloride stress corrosion cracking but several failures in weldable 13Cr pipeline material have occurred at girth welds and anode pads. Three mechanisms were identified including:

- External fractures resulted in failures resulting from hydrogen-induced stress cracking (HISC) where the hydrogen was generated by the cathodic protection system. Fractures were mixed intergranular and transgranular with secondary intergranular cracks perpendicular to the main fracture, typical of hydrogen-induced fracture.
- Internal failure due to sulphide stress cracking (SSCC)

Table 10: Duplex stainless-steel Type 2205 - Composition.

Cr	Ni	Mo	N	Fe	PREN
21 - 23	4.5 – 6.5	2.5 – 3.5	0.08 – 0.2	rem	30.5 – 38

Table 11: Duplex stainless-steel Type 2205 - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	HISC	MIC	Sulphur
A	XX	XXX	A	XXX	uncertain	XX	X	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 12: Duplex stainless-steel Type 2205 - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	HISC	MIC	Sulphur
---	T > 52 ºC	T >16 ºC	HRC < 25	---	---	-850 mV SSCE	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 13: Super duplex stainless steel - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
24 – 26	6 – 8	3 – 5	0.24 - 0.34	Rem	Cu 0.5	38 - 47

Table 14: Super duplex stainless steel - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
R	X	XX	A	A	A	uncertain	XX	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 15: Super duplex stainless steel - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 84ºC	T > 21ºC	HRC < 25	---	---	---	-850 mV SSCE	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

where the hydrogen was generated by a corrosion process adjacent to the crack area. Fractures were similar to the HISC and occurred in the ‘lean’ weldable 13Cr material (no molybdenum).

- Internal failure resulting from embrittlement at high temperature (above 110 ºC) resulting in intergranular cracking (sensitization). Fractures propagated along the grain boundaries due to reduced corrosion resistance in these areas.

In the absence of oxygen, the weldable super martensitic 13Cr material would be expected to be resistant to corrosion by the carbonic acid and hydrogen sulphide in the produced fluids though may be at risk during early field life if the pH falls below 3.5. This may occur if the pipeline is allowed to cool at high pressure. A 13Cr pipeline would be at risk from external HISC and would best be employed as pipe-in-pipe. With oxygen present from the MEG addition, this material is not considered suitable.

10.3 Duplex stainless-steel type 2205 (UNS 31803)

Tables 10 to 12 present the chemical compositions of Duplex Stainless-Steel Type 2205 as well as the corrosion mechanisms which may occur in Duplex Stainless-Steel Type 2205.

DSS type 2205 is the most utilized duplex stainless steel for pipelines. It is attractive because of the combination of high yield strength and corrosion resistance. However, type 2205 shows a marked decrease in yield strength as the operational temperature increases. In the absence of material-specific test data, the reduction in yield strength would be 135 MPa at ~130 ºC.[27] For comparison, carbon manganese steel shows a reduction in yield strength of ~45 MPa.

DSS 2205 has a good track record. It is not expected to show general corrosion but is susceptible to pitting and crevice corrosion at temperatures above 25 ºC and is susceptible to chloride stress cracking at elevated temperatures. The present limiting temperature for DSS is 140 ºC, though NORSOK M-001 recommends a maximum service temperature of 100 ºC when oxygen is present. This latter restriction is generally considered over-conservative for submarine pipelines and appears to have arisen from the Norwegian experience with the early 2205 pipelines that showed highly irregular properties at the welds. Modern welding techniques have largely overcome the wide variations in mechanical and corrosion properties. In the absence of oxygen, type 2205 DSS would be resistant to corrosion by the carbonic acid and hydrogen sulphide in the produced fluids. It would be at risk from external HISC and would best be employed as pipe-in-pipe, otherwise, the cathodic protection system anodes would require current limitation devices installed to avoid HISC. Though MEG would confer some inhibition, the concentration of oxygen present from MEG addition makes this material unsuitable.

10.4 Super duplex stainless steel (UNS S32750)

Tables 13 to 15 present the chemical compositions of Super Duplex Stainless Steel as well as the corrosion mechanisms which may occur in Super Duplex Stainless Steel.

The yield strength of super duplex stainless-steel type 2507 is reduced at elevated temperatures. In the absence of material-specific test data, the reduction in yield strength would be 90 MPa at ~130 °C.[27] For comparison carbon manganese steel shows a reduction of 45 MPa. SDSS type 2507 has better corrosion resistance than type 2205 and is not generally corroded. There is a risk of pitting and crevice corrosion and CSCC. This material has been used at temperatures up to 180°C transporting fluids with a carbon dioxide partial pressure of 38 bara and 40 ppm hydrogen sulphide, however, with no oxygen present. NORSOK M-001 recommends an upper limit of 140 °C and this value is understood to allow for the presence of oxygen. The presence of MEG would confer some inhibition, which may extend the service temperature slightly. The main risk would be early in field life when the pH is most acidic. In the absence of oxygen, type 2205 DSS would be resistant to corrosion by the carbonic acid and hydrogen sulphide in the produced fluids. Though sensitive to high concentrations of chloride at high temperatures, the shift in pH as formation water would be produced would reduce the risk of pitting and cracking. With oxygen present from the MEG addition, this material is questionable and would require simulation testing. SDSS would be at risk from external HISC.[28,29] and would require control of the potential provided by the cathodic protection system; anodes would require to be fitted with current limiting devices. The material would require to be protected externally with a temperature-tolerant coating under the thermal insulation. Thermal-sprayed aluminium is understood to be a suitable coating, and the alternative would be to use the material in a pipe-in-pipe configuration.

11. Pipe-in-pipe configuration

A pipe-in-pipe insulation system consists of a single production flowline concentrically positioned inside a protective pipe jacket. Improved insulation can be achieved by filling the annulus space with polymeric foam and silicate microspheres or by the establishment of an active vacuum. A pipe-in-pipe system was a logical progress for shallow water offshore insulated flowlines from onshore insulated pipeline experience by employing proven techniques and materials. The attractiveness of pipe-in-pipe flowlines for deepwater is because they are simple to fabricate, use low-cost proven materials, and because a high-strength protective steel jacket offers nearly unlimited depth capabilities. However, the deepwater versions of these systems can be cost-prohibitive for small or marginal economic fields.

The pipe-in-pipe system is well suited for all relevant water depths and provides, through a 3-4 thick insulation layer, an excellent U-value in the range of 0.8-3.5W/m² °C. A typical pipe in the pipe system for reel lay (see Fig. 6) consists of a casing pipe housing an insulated wrap flowline pipe concentrically positioned in the carrier pipe employing spacer blocks placed every 2.5m on the production flowline. Insulation material is strapped and attached to the production flowline pipe using galvanic steel, tape or band wire. The assembly of pipe in pipe consists of pulling the production pipe into the outer casing pipe in one continuous length while securing spacer blocks and insulation material on the production flowline pipe.

A basic pipe-in-pipe concept applicable for other methods of installation (S-lay, J-lay, Towing) comprises an inner product carrying pipe inside an outer sleeve pipe. Variations occur when the specific detail of pipe materials, bulkhead configuration, insulation system, field joints or method of fabrication change. A basic pipe-in-pipe concept applicable for other methods of installation (S-lay, J-lay, Towing) comprises an inner product carrying pipe inside an outer sleeve pipe. Variations occur when the specific detail of pipe materials, bulkhead configuration, insulation system, field joints or method of fabrication change. The sleeve (or outer) pipe has a multipurpose role in the design of a pipe-in-pipe system. Keeping the insulating material dry is one of the most basic requirements when designing and installing an insulated subsea pipeline. An obvious solution is to surround the insulation with an external waterproof sleeve (wet insulated system). The use of a sleeve will also protect the insulation material from mechanical damage during installation and service. It reduces the overall thermal loads within the system and can reduce the installation stresses experienced by the

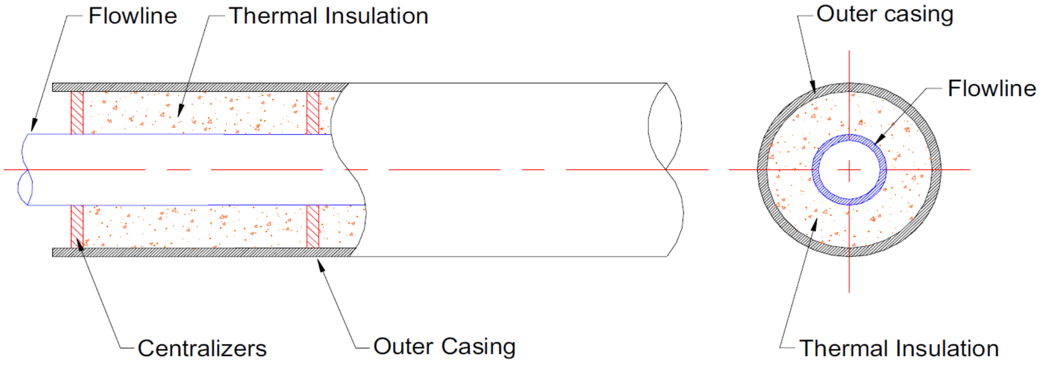

Fig. 6: Typical pipe in the pipe system.

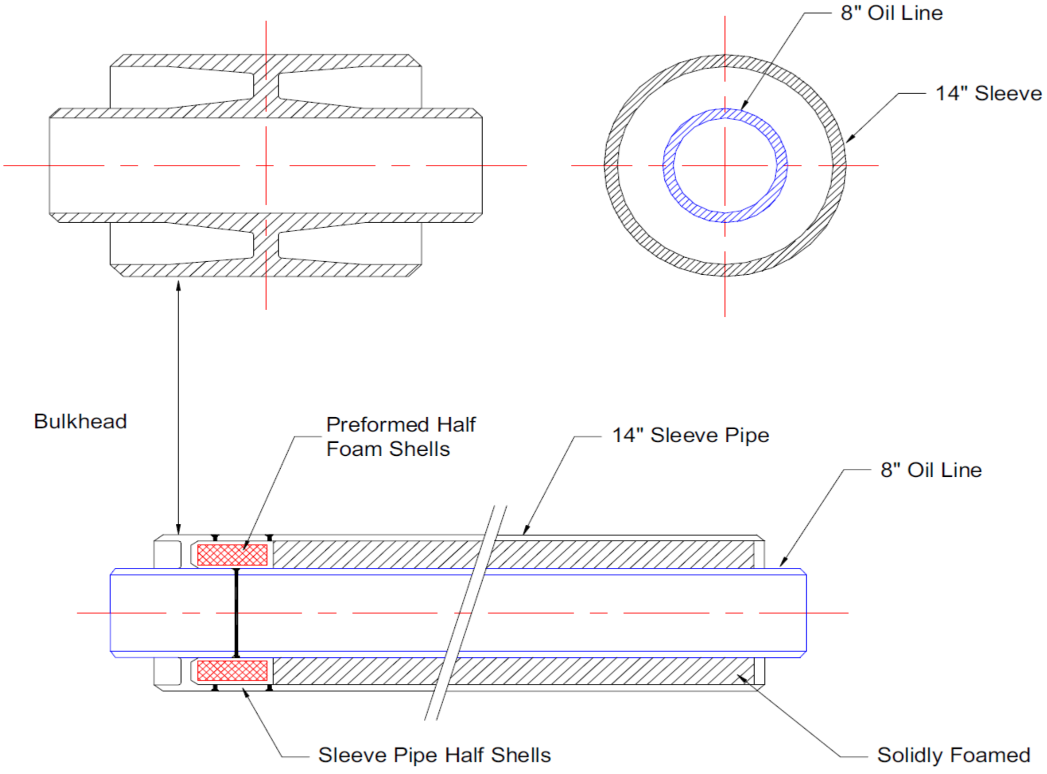

Fig. 7: Bulkhead assembled between 8-in oil line and 14-in sleeve.

system.

Load transfer can occur between product carrier pipe and sleeve pipe, which results in reduced thermal expansion. This is typically achieved by the use of a welded connection (bulkhead) between the inner and outer pipe that also provides a high-integrity water stop (see Fig. 7. During the assembly of the pipe in the pipe system, the flowline joints are welded together and insulation field joints are applied to fill the gaps at the welds. The sleeve pipes are joined by fillet welding half-shell steel sleeves over the insulation field joints. Preformed half foam shells are top surface fire resistant to prevent arc burn during the welding operation. Preheating may be required for the TIG orbital welding process but there is no post-welding heating for welded joints of C-Mn steel pipe having nominal wall thickness less than 49 mm. In the pipe-in-pipe option, the solid CRA production pipe is not exposed to aerated seawater and consequently, there would be no risk of external corrosion, chloride stress corrosion cracking and hydrogen embrittlement.

12. Clad/Lined pipe

12.1 General comment

API 5LD is the principal document relevant to line pipe clad/lined with CRA.[30] The carbon manganese steel pipe may be internally clad with a CRA such that there is a metallurgical bond between the CRA and the steel pipe. Bonding may be achieved by co-extrusion of pipe or by forming the pipe from a roll-bonded plate. After forming the pipe, the complete assembly is heated to solution anneal the CRA material to recover the corrosion resistance properties. Other minor procedures to form metallurgically bonded pipe are weld overlay into steel pipe. In the alternative procedure, the CRA inner layer is installed into the steel pipe as a separate liner mechanically bonded to the steel. The CRA liner is inserted into the steel pipe and hydraulically pressurized to expand the liner by yielding. The steel pipe is also expanded but is kept within its elastic limit. The steel pipe may be further expanded to 1% yield to ensure circularity. The elastic spring back of the outer pipe is greater than the plastic expansion of the inner pipe and the residual compressive stress in the inner pipe is reported to be in the region of 50-100 MPa.[31,32] As the temperature increases the differential expansion of the liner compared to the carbon steel pipe will increase the compressive stresses in the liner. This compressive stress should provide a degree of ‘buffer’ against the applied stress from the operational pressure, reducing the stress in the material and consequently the risk of both sulphide and chloride stress cracking. The mechanically bonded pipe must have the CRA liner attached to the steel pipe at the pipe ends to enable girth welding of the pipe. At the triple point, where the CRA liner, steel pipe, and weld overlay meet, these residual stresses and dissimilar material interfaces introduce further complexities. This area is particularly vulnerable to stress concentration and potential failure if not carefully monitored and controlled during installation and operational phases. The primary issues with CRA-clad pipe welding include Hi/Lo misalignment, which can result in thinning of the CRA layer and reduce corrosion resistance. Achieving proper fusion between the CRA cladding and steel backing at the weld interface is challenging. Additionally, excessive heat input during welding can affect the clad layer's properties, compromising its integrity in aggressive environments.

12.2 Triple point-CRA mechanically lined pipe

12.2.1 Sealing with weld overlay in mechanically lined pipes

Sealing with weld overlay is a widely adopted method in mechanically lined pipes (MLPs), particularly for sealing the internal liner at an optimized distance from the pipe end. This method typically involves the use of a corrosion-resistant alloy (CRA) weld overlay, such as Alloy 625, to cover the remaining length of the pipe. The weld overlay forms a "triple point" at the intersection of the steel pipe, liner, and weld overlay, which is a critical region that requires careful inspection and control (Fig. 8). The primary function of the weld overlay is to provide corrosion resistance while ensuring a secure bond between the CRA liner and the steel pipe. However, the intersection of these materials at the triple point introduces complexities that pose significant challenges during installation and operation, particularly in subsea environments.

12.2.2 Challenges of triple point in mechanically lined pipes

The triple point, where the CRA liner, steel pipe, and weld overlay meet, is recognized as a vulnerable area in MLPs due to its susceptibility to defects. These defects, such as lack of fusion or crack initiation, are often exacerbated under cyclic loading conditions, especially during reel-lay installation or in-service operations. As the transition between dissimilar materials (CRA liner, carbon steel, and weld overlay) generates stress concentrations, the risk of fatigue failure increases (Fig. 9). Full-scale fatigue testing on CRA-MLPs, as reported by Reda *et al.*[31] (2024) demonstrated that cracks tend to initiate at the triple point due to the residual stress concentrations present in this junction. The transition between the CRA liner and the steel pipe, particularly during installation, can lead to the development of flaws that are difficult to detect through conventional non-destructive testing (NDT) methods. Despite the widespread use of CRA-MLPs in subsea applications, current industry standards, such as DNV-ST-F101 and API 5LD, do not explicitly define the triple point or provide clear acceptance criteria for defects in this area. This creates uncertainty in pipeline design and fatigue performance assessments. Although full-scale testing has shown promising fatigue resistance in controlled conditions, the industry still lacks standardized guidelines for evaluating the long-term integrity of the triple point (Fig. 8). In addition, the welding process at the triple point requires stringent quality control to avoid flawssuch as lack of fusion or dis-bonding. These defects can compromise the structural integrity of the mechanical bond between the CRA liner and the steel pipe. Furthermore, traditional inspection methods like ultrasonic testing may not effectively detect these defects due to the complexity of the materials involved at the triple point.[31,32] Addressing these challenges is essential to improving the safety and reliability of MLPs, especially for subsea applications where fatigue loading is a primary concern. Implementing enhanced testing methods and refining inspection protocols will help mitigate the risks associated with the triple point and improve the long-term performance of these pipelines.

12.3 Challenges in welding CRA-clad pipes

Alignment is one of the most critical factors influencing the success of welding CRA clad pipes. The integrity of the welded joint, the quality of the CRA barrier, and the overall

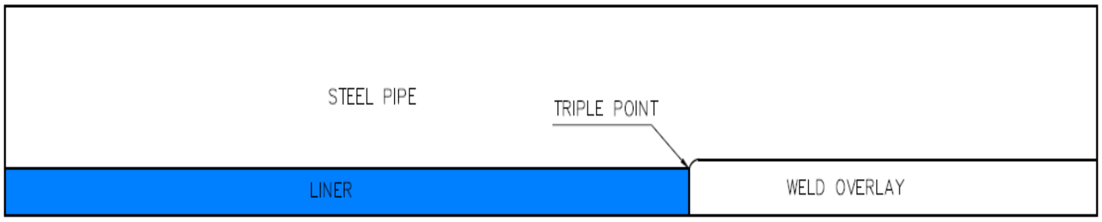

Fig. 8: Schematic of lined pipe with weld.

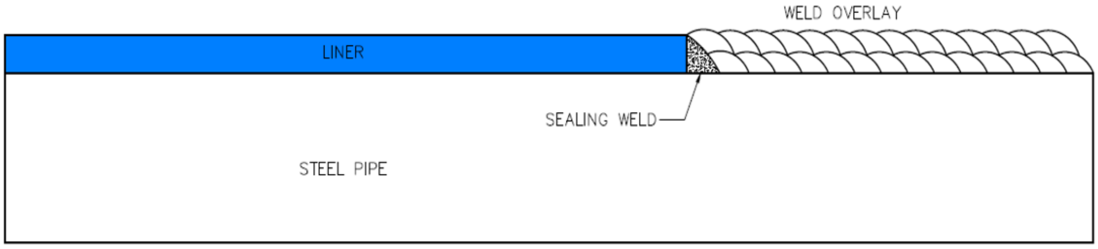

Fig. 9: Schematic of typical liner cladding interface.

reliability of the pipeline depend heavily on proper alignment. Misalignment during the welding process can introduce significant risks, such as welding defects, loss of structural integrity, and potential failure under operating conditions. Fig. 10 illustrates the importance of proper alignment in CRA-clad pipes. The top section of the figure shows a cross-sectional view of two pipes being joined, highlighting the importance of aligning the CRA layers. The bottom sections of the figure compare a well-aligned joint with poor alignment, showing the misalignment of the CRA layers and its potential consequences.

12.3.1 Dimensional tolerances of clad pipes

One of the major alignment challenges in CRA-clad pipe welding is the variability in the dimensional tolerances of the pipes themselves.[33-35] Manufacturers may claim improvements in these tolerances, but in practice, variations in pipe diameter, roundness, and wall thickness remain common. These variations make it difficult to achieve the required fit-up of adjacent pipes, where the CRA layers must align perfectly to avoid defects at the weld interface (Fig. 10). Out-of-roundness (OOR) further complicates the process, especially for large-diameter pipes. Large pipes tend to spring back after cutting, making it challenging to align the CRA layers accurately. The OOR in the middle of the pipe or away from the ends is often less controlled, contributing to alignment problems. For instance, a misalignment of 6 mm was observed in a subsea installation, which significantly hindered the welding process.[35]

12.3.2 Impact of misalignment on welding

Misalignment introduces several issues during the welding process, particularly when the CRA layers do not align properly:

- Radial Offset: Misalignment creates a radial offset between the abutting ends of the pipes. This offset reduces the CRA layer thickness at the weld, compromising the pipe's corrosion resistance. The welding process becomes more challenging, as the misaligned layers must be ground to minimize the offset (Fig. 10). Excessive grinding, however, can expose the carbon steel backing, leading to corrosion and other structural issues.
- Welding Defects: Poor alignment increases the likelihood of welding defects such as incomplete fusion, voids, or gaps. Additionally, significant misalignment introduces stress concentration points, which can lead to cracking under operational stresses or during thermal expansion.

12.3.3 Allowable misalignment tolerances

Hi/Lo misalignment, a critical issue in CRA-clad pipeline welding, occurs when the ends of adjoining pipes are not properly aligned during the girth welding process. According to DNV-ST-F101, Section 12.3.3 "Allowable Misalignment Tolerances", the maximum allowable Hi/Lo misalignment for CRA-clad pipes is 1.0 mm, unless otherwise qualified or if it does not reduce the thickness of the CRA barrier below the specified limit. Misalignment exceeding this tolerance creates uneven weld geometries that lead to stress concentration points, compromising the weld's structural integrity and corrosion resistance. Common defects caused by misalignment include incomplete fusion, crevices, and localized thinning of the CRA layer. These defects are particularly problematic in sour service conditions, where exposure to hydrogen sulfide (H_2S) accelerates material degradation, promoting stress corrosion cracking (SCC) and eventual pipeline failure.

The welding of CRA-clad pipes presents unique challenges, particularly the need to maintain a continuous corrosion-resistant barrier across the weld joint. Hi/Lo misalignment often requires grinding to level misaligned surfaces, but excessive grinding can breach the CRA layer, exposing the carbon steel backing to corrosive media. Such exposure significantly increases the likelihood of SCC and fatigue failure, particularly in subsea environments where pipelines experience cyclic loading and high operational stresses. A recent failure of a 36-inch CRA-clad pipeline exemplifies these challenges.[35] The failure occurred at a girth weld connecting the riser to a subsea spool, where a significant Hi/Lo misalignment of 6.3 mm was observed, far exceeding the DNV-ST-F101 allowable limit specified in Section 12.3.3. Corrective grinding was performed to address the misalignment but inadvertently breached the 3 mm Alloy 825 CRA cladding, exposing the underlying X65 carbon steel to wet sour gas. This exposure, combined with the stresses from the misalignment and the corrosive environment, initiated cracks at the weld root. Within 14 days of operation, SCC propagated through the carbon steel, resulting in a leak. The thinning of the CRA layer exacerbated the issue, leaving the exposed carbon steel vulnerable in the sour service environment. This failure highlights the critical impact of Hi/Lo misalignment and improper grinding on the integrity of CRA-clad pipelines. It demonstrates how exceeding the allowable misalignment tolerance specified in DNV-ST-F101, Section 12.3.3, can compromise the weld joint, leading to rapid degradation and loss of containment in operational pipelines.

12.3.4 Mitigating alignment issues

Several strategies can mitigate alignment issues during CRA-clad pipe welding:

- Dimensional Control: Pre-installation dimensional checks are crucial for ensuring proper alignment. By matching pipes with similar dimensions and adjusting for any out-of-roundness, welders can minimize misalignment.
- Rotating Pipes: During welding, rotating the pipes to achieve the best fit helps minimize radial offsets. This technique ensures that internal misalignment is evenly distributed around the circumference of the pipe.
- Pup Pieces: Short sections of pipe (pup pieces) can be used to compensate for dimensional variations and improve fit-up during installation.

12.3.5 Importance of Proper Fit-Up

Proper alignment is essential to maintain the integrity of CRA-clad pipes. Even minor alignment issues can result in significant corrosion risks, especially in aggressive environments like subsea pipelines. Careful attention to alignment during the fit-up and welding process can reduce the likelihood of these issues and ensure the long-term performance of the pipeline.

12.4 Weldable 13Cr (UNS 41425)

Tables 16 to 18 present the chemical compositions of Weldable 13Cr as well as the corrosion mechanisms which may occur in Weldable 13Cr. This material was discussed in detail in Section 2.2. In cladding, it was originally provided as centricast pipe and is available as metallurgically and mechanically bonded cladding/liner.

12.5 Stainless steel type 316L (UNS S31603)

Tables 19 to 21 present the chemical compositions of 316L as well as the corrosion mechanisms that may occur in 316L. The 316L is available as a mechanically bonded liner. It is commonly used for anaerobic gas pipelines where there is little or no production of formation water. It has a modest cost in comparison to solid CRA materials. Type 316L does not suffer general corrosion, but it has a low resistance to pitting and crevice corrosion. And CSCC in oxygenated saline water, cracking may occur in waters containing above 250 ppm chloride and 1 ppm oxygen when at elevated temperature. As the liner will be 2–3 mm thick, pitting would rapidly expose areas of the carbon steel, which would suffer a high rate of corrosion. The threshold stress for CSCC is 10% of yield and though the liner would be in compression for most of the service life, some areas adjacent to the welds may be in tension after blowdown. Corrosion fatigue has occurred with 316L materials used in the process plant, and it is possible that thermal cycling would cause pits to develop into fatigue cracks.

12.6 Stainless steel type 317L (UNS S31703)

Tables 22 to 24 present the chemical compositions of 317L as well as the corrosion mechanisms which may occur in 317L.

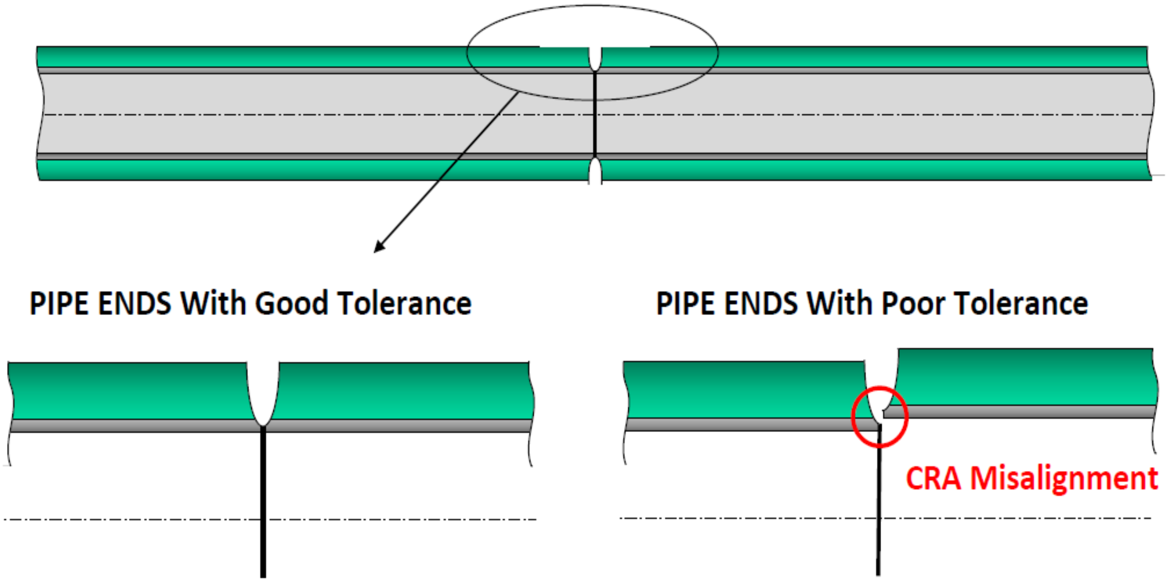

Fig. 10: Welding misalignment between adjacent pipes.

Table 16: Weldable 13Cr - Composition.

Cr	Ni	Mo	N	Fe	PREN
12 – 14	5 – 6	2.5 – 3.5	---	Remainder	22 – 25

Table 17: Weldable 13Cr - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
XX	XXX	XXX	A	R	uncertain	X	XX	X

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 18: Weldable 13Cr - Condition

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
0.05 mm/yr	T > 2 °C	T > 0 °C	HRC < 28	---	---	---	-850 mV SSCE	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

SS type 317L is similar to type 316L. It contains 3% molybdenum and some nitrogen which improve the pitting and crevice resistances.

12.7 Stainless steel type 904L (UNS N08904)

Tables 25 to 27 present the chemical compositions of 904L as well as the corrosion mechanisms that may occur in 904L. This material can only be used as a mechanically bonded liner. Stainless steel (SS) type 904L is borderline super austenitic stainless steel. It was originally developed for handling sulphuric acid but has been identified as an attractive claddingof pipelines that must handle corrosive saline waters and consequently, it is commonly used in desalination plants as a replacement for 316L. The material was developed before the beneficial effect of nitrogen alloying was identified. The absence of nitrogen does, however, reduce the variation in properties that can occur at weldments, and overall, 904L has good weldability. The resistance to CSCC is markedly improved compared to type 316L/317L because of the high nickel content (24%). Though 904L has good resistance to pitting, crevice corrosion, and CSCC it is not immune to these forms of corrosion at high temperatures.

Table 19: Stainless steel Type 316L - Composition.

Cr	Ni	Mo	N	Fe	PREN
16 - 18	10 - 14	2 – 3	---	Remainder	23 - 28

Table 20: Stainless steel Type 316L - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
R	XXX	XXX	A	XXX	XX	X	R	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 21: Stainless steel Type 316L - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 2 °C	T > 0 °C	HRC < 22	T > 60 °C	---	---	-850 mV SSCE	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 22: Stainless steel Type 317L - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
18 – 20	11 – 15	3 – 4	---	Remainder	---	28 - 33

Table 23: Stainless steel Type 317L - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
R	XXX	XXX	A	XXX	XX	X	R	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 24: Stainless steel Type 317L - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 5 °C	T > 2 °C	HRC < 22	T > 70°C	---	---	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 25: Stainless steel Type 904L - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
19 – 23	23 – 28	4 – 5	---	Remainder	Cu 1 – 2	32 – 39

Table 26: Stainless steel Type 904L - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
R	X	XX	A	uncertain	R	X	R	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 27: Stainless steel Type 904L - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 60 °C	T > 18 °C	HRC < 22	T > 121	---	---	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Useful information was gathered from a review of nuclear waste containment studies.[36] These are intended to identify materials that must remain integral for many years. The studies indicated that the tolerance to chloride and temperature was related to pH. In stagnant aerobic conditions at 90 ºC, pitting was initiated on 904L at 18,300 ppm chloride, whilst at 140 ºC, the tolerance to chloride reduced to 10,500 ppm. At higher pH values, the tolerance to chloride increased to 20,600 ppm. In anaerobic conditions, the tolerance to chloride concentration increased to > 100,000 ppm. The presence of sulphate appeared to improve resistance to pitting, perhaps because of competitive absorption (in the nuclear waste studies, the sulphate levels were 1,700 ppm).

The 904L has a higher linear coefficient of expansion than carbon steel and elongates more than the pipe into which it has been expanded as the temperature increases. At ambient temperature, the compressive stress in the liner is in the range of 50-100 MPa. As temperature increases and the liner expands and elongates, the compressive stress increases. For an increase in temperature from ambient to 150 ºC, the longitudinal expansion of the 904L in a 12.2 m pipe will be ~20 mm, whilst the expansion of the steel will be ~9 mm. Consequently, at operating temperature and pressure, the liner will be in compression and resistant to CSCC.

During blowdown, the liner will shrink, and the compressive force will decrease. The HAZ may shift into tension; however, the threshold stress for CSCC is ~75% yield, which should be above the stress resulting from liner contraction after blowdown. Tests on 904L indicate that it is highly resistant to corrosion fatigue and is susceptible to some forms of microbiological-influenced corrosion.

12.8 Stainless steel type 254-SMO (UNS S31254)

Tables 28 to 30 present the chemical compositions of 254-SMO as well as the corrosion mechanisms which may occur in 254-SMO. The 254-SMO and other 6Mo stainless steels have only recently become available in quantity for oil and gas service. The 254-SMO was developed over twenty years ago to be an improved 904L; this is achieved by increasing the molybdenum content to 6% and the inclusion of nitrogen. The generic identifier of this form of austenitic stainless steel is UNS S31254. An alternative is AL-6XN, which has a PREN of ~45 and a nickel content of 24% which confers improved resistance to CSCC. However, this alloy remains may not be as readily available as UNS S31254. This material will not suffer general or localized corrosion. Despite the improved performance compared to 904L, the pitting and crevice temperatures of this alloy are lower than the operational temperature, so there remains a risk of pitting and crevice corrosion. The higher molybdenum and nitrogen increase resistance to pitting, but the lower nickel reduces the resistance to CSCC. Overall, however, the alloy has greater corrosion resistance than 904L, though it is not as resistant as alloy 625. The 254-SMO is believed to be resistant to microbiological corrosion because of the high molybdenum content.

12.9 Alloy 825 (UNS N08825)

Tables 31 to 33 present the chemical compositions of 825 as well as the corrosion mechanisms that may occur in 825. Alloy 825 is the most widely used material for clad/lined pipelines. This alloy is favored for sour service conditions because alloy 825 has the advantage that it is immune to SSC and immunes to CSCC at the operating temperature. Alloy 825 is reported

Table 28: Stainless steel 254-SMO - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
19.5 – 20.5	17.5 – 18.5	6 – 6.5	0.18 - 0.22	Remain	0.5 – 1.0	42 - 45

Table 29: Stainless steel 254-SMO- Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
R	uncertain	X	A	uncertain	R	R	R	R

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 30: Stainless steel 254-SMO - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 70 ºC	T > 45 ºC	HRC < 25	T > 121 ºC	---	---	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 31: Alloy 825 - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
19.5 – 23.5	38 - 46	2.5 – 3.5	---	Remainder	Cu 1.5 – 3.0	28 - 35

Table 32: Alloy 825 - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
A	XX	XX	R	A	uncertain	uncertain	R	A

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 33: Alloy 825 - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	HISC	Sulphur
---	T > 30 °C	T > 12 °C	Ni > 42%	T > 200 °C	---	---	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 34: Alloy 625 - Composition.

Cr	Ni	Mo	N	Fe	Other	PREN
20 - 23	Remainder	8 – 10	---	5 max	---	46 - 56

Table 35: Alloy 625 - Corrosion Mechanism.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	Sulphur
R	A	uncertain	R	R	R	R	R

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

Table 36: Alloy 625 - Condition.

General	Pitting	Crevice	SSC	CSCC	Fatigue	MIC	Sulphur
---	T > 85 °C	T > 50 °C	Ni > 42%	Ni > 42%	---	---	---

Key: XXX = high risk; XX = moderate risk; X = low risk; A = acceptable; R = resistant.

to have cracked at temperatures exceeding 200 °C. The low PREN means that the alloy is susceptible to pitting and crevice corrosion, which may be severe in the presence of oxygen. Since the thickness of the CRA layer is 2-3 mm, the risk of perforation of the layer is high which would result in local and excessive corrosion of the steel outer pipe at the area of pit perforation. Alloy 825 has been identified as suffering pitting corrosion because of microbial activity.

12.10 Alloy 625 (UNS N06625)

Tables 34 to 36 present the chemical compositions of 625 as well as the corrosion mechanisms which may occur in 625. Alloy 625 may be used as a solid CRA as it has a high yield strength but is more cost-effective to use as a cladding/liner. It is available as a metallurgically and mechanically bonded cladding/liner. Alloy 625 is attractive for severe corrosive sour service because it is immune to SSC and CSSC because of the high nickel content above 40%. It is not completely resistant to pitting and crevice corrosion at elevated temperatures. However, it should not show pitting at the reduced oxygen and chloride concentrations in the absence of adherent deposits. The MEG should provide some inhibition and the increase in pH as the chloride concentration increases will also reduce the risk of pitting and crevice corrosion. Alloy 625 has good resistance to corrosion fatigue. Alloy 625 is believed to be resistant to microbiologically influenced corrosion because the molybdenum content is above 6%.

13. Industry experience

This section provides an overview of significant failure events involving Duplex Stainless Steels (DSS), Martensitic Stainless Steels (WMSS), and Corrosion-Resistant Alloys (CRA) in offshore applications, particularly focusing on high-pressure, high-temperature (HPHT) fields in the North Sea. These cases underline the risks associated with hydrogen-induced stress cracking (HISC), stress corrosion cracking (SCC), and inadequate heat treatments, as well as challenges specific to CRA materials.

13.1 Duplex stainless steel (DSS)

- **Dutch Sector (1980s):** A duplex stainless-steel pipeline fractured during pressure testing after a GTAW repair weld. The microstructure predominantly contained delta-ferrite (δ-ferrite), resulting from high cooling rates post-PWHT. The failure was attributed to HISC, associated with residual hydrogen from welding and high δ-ferrite content.
- **Marathon Oil (1998):** Cracking in 22Cr DSS production tubing, cold-worked to 1000 MPa, was linked to HISC caused by galvanic coupling with carbon steel casing, introducing hydrogen levels above 30 ppm.
- **Foinhaven (1997):** Two forged subsea hubs exhibited cracking due to high stresses, high ferrite content, undesirable grain orientation, and the absence of protective coatings. HISC was identified as the primary cause.
- **Norway (1996):** A forged 25Cr bend fractured during pressure testing. Failure analysis revealed an excess of 20% intermetallic phases, with poor heat treatment leading to embrittlement.
- **Norwegian Sector (1999):** A 22Cr DSS manifold fractured during pressure testing after two years subsea. The failure was associated with 80% δ-ferrite in a fillet weld, elevated hydrogen content from cathodic protection (CP), and high stresses, culminating in HISC.

13.2 Martensitic stainless steel (MSS)

- **North Sea (1998):** A 13Cr WMSS pipeline suffered severe pitting corrosion after anchor damage led to seawater flooding. The failure investigation revealed significant pitting (10-12 mm deep) due to the material's susceptibility to corrosion when exposed to raw seawater.
- **Statoil Åsgard (1998):** Fracture occurred in a 13Cr WMSS pipeline girth weld shortly after reeling. HISC was the

root cause, attributed to high stresses and excessive hydrogen in the filler material.

- **Statoil Åsgard (2002):** Two fractures were observed in a 13Cr WMSS flowline associated with anode pad welds. Disbanding of field joint coatings, combined with high stresses, led to HISC, which initiated and propagated the cracks in the HAZ.

13.3 Corrosion failures of CRA materials in HPHT fields (North Sea)

Corrosion failures of CRA in HPHT fields have occasionally been reported, although operators are cautious about releasing detailed information. Key cases are summarized below:

- **Weldable 13Cr Flowlines:** Pitting corrosion at welds occurred due to seawater ingress, indicating vulnerability in the weld zones.
- **25 Cr SDSS:** Pitting and possible CSCC initiation were observed, attributed to oxygen ingress.
- **Alloy 718 Tubing Hangers:** Alloy 718 (53Ni-20Cr-3Mo) exhibited hydrogen embrittlement, likely due to poor heat treatment, resulting in embrittlement similar to Alloy 825.
- **Franklin Field (Alloy 718 Tubing Hanger):** Hydrogen embrittlement, linked to the presence of the delta phase, was caused by inadequate heat treatment.
- **Shearwater (Alloy 718 Tubing Hanger):** Brittle fracture occurred, with suspected hydrogen embrittlement resulting from galvanic corrosion.
- **DSS:** Acidic scale removal chemicals attacked the DSS matrix, highlighting the importance of chemical inhibition during cleaning operations.

These failure cases illustrate the critical importance of proper material selection, coating systems, heat treatments, and hydrogen management to prevent such incidents in HPHT environments.

14. Testing programme for candidate materials

14.1 Selecting samples for testing

The range of alloying elements of a generic CRA can vary by several percentages. By minimizing one or more expensive alloying elements, suppliers would be able to produce an attractively priced product that meets the nominal specification. Additionally, there would be natural variations in composition between heats. All the material supplied will be to specification but will demonstrate differences in mechanical properties and corrosion resistance.

When evaluating suppliers, PREN should be considered in the cost-benefit analysis and suppliers should be required to guarantee that all material supplied will meet this PREN. For clad/lined pipe the cost of fabrication of the pipe is generally the largest fraction of the total cost and the cost of the CRA lining is less significant. The cost of fabrication of solid CRA pipe is a lower percentage of the total pipe cost.

It is generally cost-effective to screen generic CRAs to identify the most suitable for the proposed service and then, having identified an acceptable CRA, to select a Supplier. To select and validate, the suppliers would then require additional testing. However, it may be possible to identify the potential final Supplier in advance and do the testing of generic CRAs on the materials that are most likely to be purchased. One approach to this would be to normalize material cost according to the guaranteed PREN values.

14.2 Sample preparation

Though it would be ideal to use samples cut from specimen pipe, this is not considered necessary. Samples cut from a plate that has been heat treated similarly to the pipe material or lining/cladding will be acceptable. For the super duplex, the samples should be the same thickness as the eventual pipe. For the clad pipe specimens, the test material should be the same thickness as the pipe cladding. If a slightly thicker plate must be used, then an appropriate adjustment to the applied stress will have to be made, and HAZ grain size will be measured to allow comparison with the HAZ grain size produced by welding the actual thickness. The HAZ of the materials will be at the most risk of pitting and CSCC, and if these areas pass then the parent material, provided it is free of significant defects, will be acceptable. Consequently, samples should contain an area of weld typical of the welds that will be made offshore. The degree of heat tint at the weld should also be like that anticipated to be produced during the offshore welding and this tint should not be removed.

14.3 Test conditions

The purpose of the testing is to identify if these materials can tolerate acidic, oxygenated condensed water treated with MEG and the less acidic, oxygenated saline water treated with MEG. The combination of oxygen and chloride is the most aggressive species concerning pitting and crevice corrosion, whilst the combination of oxygen, chloride, and acidity relates to CSCC. Pitting and CSCC are stochastic processes and consequently, the time to initiation of pitting or cracking cannot be predicted. Tests will require to be done for a period sufficient to give confidence. At the high operational temperature, it is not possible to maintain the oxygen concentration or the carbon dioxide concentration without applying pressure. The testing will have to be done using autoclave systems. The risk of CSCC is related to the tensile stress. For the solid CRA pipes, this may be applied using four-point bed methods; this method is the most suitable for flat plate samples. The solid CRA materials show a relaxation of yield strength when held at elevated temperatures for a period. The samples will need to be heat treated to ensure that relaxation occurs. This should be done in an inert atmosphere to avoid the production of abnormal surface films. The stress should be fixed as judged necessary for pipeline operation, though it is usually set at 72% actual yield strength.

As discussed in Section 2, the clad material may be in compression when in service at operational temperature. Four-point bend tests on plate material are the most suitable test configuration as this test provides both tensile and compressive stress across the samples as the inner face of the constrained sample will be in compression. The presence of gases other than carbon dioxide and hydrogen sulphide is not required as they are inactive for corrosion. This means that the autoclaves can operate at a reduced pressure with the sparging gas formulated from carbon dioxide with trace hydrogen sulphide. The operating pressure would be set to ensure the required partial pressures of carbon dioxide and hydrogen sulphide. One procedure that requires attention by the test house will be the method of introducing oxygen into the system. Usually, test fluids are de-oxygenated by a combination of vacuum and pre-gassing before or after introduction into the autoclave. The oxygen may have to be introduced into the autoclave by injection in MEG after the set-up of the autoclaves but before the increase in pressure and temperature.

14.4 Preparation and evaluation of the samples

Before the tests, the surface of samples must be well inspected at magnification (usually 10x with 100x for defects) and the surface condition recorded, preferably photographically. Samples should be free of grease, fingerprints, *etc.*, but the oxide tint around the weld should not be removed. After testing, the samples should be examined at magnification (10×), and defects examined at higher magnification (100×). The purpose is to identify any pits that may have been formed and the depth of the pits. Dye penetrant testing may also be used to identify pits and cracks.

14.5 Standard tests

Standard tests are used to screen materials and for quality assurance/quality control (QA/QC). For screening materials, the CPT and CSCC tests are perhaps the most critical for this project if they can be done on the HAZ and simulating pipeline conditions. The tests should be done with simulated produced water, *i.e.*, sodium chloride test, and with oxygen and MEG present. For the proposed materials, ambient testing in aerated seawater is not required, ferric chloride testing is irrelevant, and SSC testing is not necessary. The weight loss of CRA materials during short-term testing is minimal as these materials do not corrode in a general manner. Pitting represents a tiny volume of material and, hence, small weight loss. Visual examination supplemented with dye penetrant inspection (DPI) is more useful.

15. Precautions during fabrication

15.1 Defects and contamination of the CRA surface

Corrosion tends to initiate at defects or aberrant areas on the CRA surface. The defects may be introduced by handling the pipe before or during fabrication. Ferrous materials in contact with the CRA surface may impart iron particles into the surface; this iron subsequently corrodes and induces pitting corrosion. To avoid this all handling and lifting equipment should be rubber-covered. When the girth welds are cleaned the CRA surface must not be blasted using carbon steel shot or copper grit. A blasting material which does not contain iron such as glass beads or garnet is acceptable. Garnet should be checked to ensure it is iron free and recycling of garnet must be restricted.

The use of ferrous-based bevelling and grinding discs should be avoided and drift of grinding dust into or from adjacent pipes must be avoided. Removal of rust on bevels should be done carefully to avoid the inclusion of the rust into the CRA weldments. Wire brushes used for surface cleaning should be fabricated with stainless steel. Contamination from carbon steel weld spatter into the pipe bore should also be avoided. The presence of iron on or embedded in the CRA surface can be identified using the ferroxyl test which is a very sensitive indicator that will detect even traces of free iron or iron oxide. It should only be used by experienced personnel and is described in ASTM A380 and Nickel Development Institute publication 11007.[37,38] If, by accident, iron is embedded in the CRA surface it can be removed using nitric acid which will dissolve iron and carbon steel particles but not damage the stainless steel. Surface smears or lightly adherent iron particles can be removed using nitric acid passivating solutions. Phosphoric acid cleaning solutions are also used quite extensively and are common where nitric acid is banned. Deeply embedded particles require the use of nitro-hydrofluoric acid pickling solutions or pastes, which can also be used for removing heat tint in the case that a faulty weld must be repaired.

15.2 Grain boundary sensitization

Galvanized steel should not contact the CRA surfaces as the zinc may be introduced into the metal surface and, during welding, the zinc migrates into the weld metal and results in later intergranular embrittlement along the grain boundaries. Similar liquid metal embrittlement can occur when surfaces that are to be welded are contaminated with lead, tin or copper. Carbon on the surface, as grease, will degrade during welding, and the carbon will migrate into the CRA, reacting with chromium to form carbides that can initiate sensitization, leading to pitting. Sources of contaminants must be removed. These are usually general dirt, hydrocarbons such as grease, oil, cutting lubricants, deposits from dirty gloves, marking crayons, paints and temperature indicators, and areas where tools have rested, *e.g.* hammers and backing bars.

15.3 Surface cleanliness

When cleaning the CRA surface before welding it is usual to use solvents. It is important to use clean solvents and clean cloths and to avoid chlorinated solvents, particularly in areas where there could be crevices formed. Acceptable solvents include alcohol and acetone.

15.4 Oxide tint

CSCC is generally initiated by pitting corrosion. The risk of pitting is known to increase in areas where irregular oxide layers are formed. After the girth weld is completed, the pipe will be cleaned by grit blasting. As it is not possible to remove the internal oxide layers after it is formed it is necessary to prevent them from being formed during pipeline fabrication. To achieve this, it will be necessary for the oxygen content to be reduced, and to achieve this, a bore purge of argon, argon-helium, or argon/nitrogen is used to prevent oxide formation. The maximum oxygen content at the start of welding is typically set to a maximum value of 1,000 ppmv (0.1%). Further reduction in the oxygen content below 1,000ppm will lead to further improvement in the corrosion resistance by reducing the severity of the tint. With an oxygen content of below 150 ppm (0.015%), it has been reported that the corrosion resistance of the weld metal is like that of the parent metal. Some tint is acceptable but must be limited. A discoloration greater than straw or high blue is considered unacceptable. Super duplex stainless steels may require special purge gas to ensure that the nitrogen is not depleted.[38] Allowing trace air (~1,500 ppm) is understood to provide sufficient nitrogen to prevent nitrogen depletion. Alternatively, a nitrogen-hydrogen mixture may be used to provide nitrogen whilst preventing excessive tint and the need for this form of shield gas should be identified during the development of the welding procedure.

15.5 Welding issues

The Nickel Development Institute (NiDI) gives considered advice on the welding of nickel-containing steels.[39] Only corrosion issues are discussed in this Report. The risk of crevice corrosion is high for the CRA materials, and it is necessary to avoid the formation of crevices at the girth welds. The root pass is the most critical area, and the weld procedure must be able to produce defect-free root passes. Dilution of the root pass may occur, resulting in reduced corrosion resistance. The use of an enhanced metallurgy for the root pass should ensure that dilution does not occur. The shape of the bevel has an impact on the number of welds that pass to complete the weld. A reduction in the number of passes will reduce grain growth in the HAZ and consequently reduce the reduction in critical pitting temperature. In this respect, the J-type bevels appear to have the advantage over V-shape bevels. If the 'nose' of the J-bevel can be complete CRA material, then the risk of dilution of the CRA is also reduced.

The heat input for duplex stainless steel must be controlled such that the cooling is at a rate that ensures the correct balance of ferrite and austenite is obtained. Excess ferrite is produced if the temperature declines too rapidly. If the temperature declines too slowly, then unfavorable phases are formed; these phases, *e.g.*, the sigma phase, may initiate pitting corrosion. The sigma phase material binds chromium and molybdenum, resulting in a local decrease in the concentration of these elements and reducing corrosion resistance. Heat input for SDSS type 2507 must be held below 2.5 kJ/mm and the maximum inter-pass temperature is limited to 150 ºC.[40] Welding of high nickel alloys is less exacting than welding the super duplex stainless steels, but heat input must be limited to avoid the formation of unfavourable precipitations that may result in sensitization and cracking.

15.6 Repair of welds

Welds in super duplex stainless steel cannot normally be repaired as the repair procedure results in unfavourable metallurgical properties in the adjacent material. Usually, a faulty weld must be completely reformed. The super austenitic and high nickel alloys (*e.g.* alloy 625) are more tolerant to repair.

16. Hydrotesting and seawater management of stainless steel and corrosion-resistant alloys

Hydrotesting and pre-commissioning of stainless steel (SS) and CRA require strict adherence to water quality standards and robust operational practices to ensure long-term pipeline integrity. The evaluation of biocides and other chemical additives for compatibility with SS and CRA materials is essential to prevent material degradation during hydrotesting and seawater exposure.[41-45]

16.1 Martensitic steel, 13% Cr and super 13% Cr steel

Hydrotesting pipelines constructed from martensitic steel demand the use of freshwater that meets stringent quality standards. Water must comply with the following parameters:

- Chloride content: < 200 ppm
- Sulfate content: < 10 ppm
- Total dissolved solids: < 500 ppm
- pH range: 6.5–7.5
- Dissolved oxygen: < 10 ppb
- Organic matter: < 2 ppm
- Suspended solids: ≤ 20 ppm
- Particle size: ≤ 50 microns
- Total bacterial count: < 10^6 bacteria per liter
- Sulfides (H_2S): Zero

If water quality deviates from these specifications, filtration, and chemical treatment are mandatory. Chlorine must be completely excluded from water. To prevent seawater ingress during installation and tie-in, rigorous precautions must be implemented. In case of seawater contamination, the system must be flushed with freshwater within seven days. Complete removal of the residual water through dewatering and drying is critical to avoid stagnant conditions that could promote localized corrosion or microbiologically influenced corrosion.

16.2 Duplex stainless steel and austenitic steel

Duplex stainless steel (22% Cr and 25% Cr), 300-series austenitic stainless steel, and Alloy 825 require similar water quality specifications as martensitic steels. This includes: (i) residual chlorine levels in the water must not exceed 0.3 ppm; (ii) hydrotesting should be conducted at ambient temperatures, and (iii) the system must be dried immediately using air or nitrogen to prevent moisture retention. Seawater ingress must be strictly avoided and if it occurs, the pipeline should be flushed with freshwater within seven days. After hydrotesting, no residual water pools should remain in the system. Thorough dewatering and drying prevent under-deposit corrosion and microbial activity, which can compromise pipeline integrity.

16.3 Super duplex and 6 Mo steel

Super duplex and 6 Mo stainless steel can be hydrotested at temperatures exceeding 15 °C (60°F) using freshwater that adheres to stringent quality standards. Residual chlorine levels must remain below 0.3 ppm. For preservation durations exceeding one week, biocide treatment is essential to mitigate microbial risks. Complete dewatering and drying are critical to ensure material integrity and prevent localized corrosion or MIC. Additionally, maintaining a high pH (above 10) in treated water is crucial for preserving the passive film on stainless steel surfaces. This is particularly important in environments with elevated chloride concentrations, where the risk of crevice corrosion is heightened.

16.4 Key considerations for hydrotesting

The water quality and chemical treatment program plays a critical role in preventing corrosion and microbiologically induced damage during hydrotesting and preservation. Common factors contributing to material degradation include high chloride levels, dissolved oxygen, and microbial activity. These risks necessitate rigorous water treatment protocols, which may include the following items:

- Biocides to eliminate harmful microorganisms.
- Oxygen scavengers to reduce dissolved oxygen levels.
- Corrosion inhibitors for enhanced protection against pitting and crevice corrosion.

Furthermore, the use of inline filtration and continuous water quality monitoring ensures compliance with water specifications, mitigating the risk of corrosion failures during hydrotesting.

17. Precautions in service

Corrosion of CRAs is more prevalent in stagnant conditions compared to flowing conditions, particularly in subsea pipelines. When the temperature exceeds the pitting and crevice corrosion initiation threshold, there is an increased risk of these localized corrosion forms, especially when flowlines are shut in and the temperature remains high. The time taken for pitting and crevice corrosion to initiate may vary, and the risk is exacerbated by the presence of high temperatures and stagnant flow conditions, which are common during operational shutdowns in subsea environments.

Reducing pressure in the flowlines will result in a decrease in the partial pressure of carbon dioxide, leading to a rise in pH, which may help in mitigating general corrosion. However, oxygen corrosion remains relatively insensitive to changes in pH. The development of scales on the internal pipe surface must be avoided, as crevices may form beneath these scales, which could serve as initiation sites for pitting or crevice corrosion. These scales may also facilitate the accumulation of solid contaminants, such as free sulfur, which can promote further localized corrosion under stagnant subsea conditions. Corrosion monitoring is typically not required for CRA systems under normal subsea operating conditions. Traditional methods like weight-loss coupons or resistance probes are generally insufficient to detect early signs of localized corrosion in CRA pipelines. If an early warning system is considered necessary, electrochemical noise monitoring should be implemented, adjusting the potential of the samples to ensure that pitting corrosion can be detected before it occurs on the pipe material. This proactive monitoring can be particularly useful in subsea pipelines, where maintenance and monitoring access are challenging. By implementing these precautions, the integrity of CRA-lined or clad subsea pipelines can be better maintained, reducing the risk of costly repairs or environmental damage due to leakage or failure.

18. Cost life cycle of CRA mechanically lined pipe

Many subsea pipeline projects face capital expenditures (CAPEX) constraints, focusing primarily on minimizing capital expenditure. This emphasis often leads to the oversight of economic analysis over the pipeline's life cycle. The oversight is particularly prevalent in projects involving joint ventures from different companies or stakeholders, where one company may be responsible for design, fabrication, and construction but not operational aspects. In such cases, the project delivery company might opt for carbon steel pipes with corrosion inhibitors due to their perceived lower CAPEX compared to CRA mechanically lined pipe. Unfortunately, the project team may overlook the life cycle costs associated with carbon steel, as well as capital equipment like dehydration plants. There is often a false assumption that the operational expenditures (OPEX) of carbon steel are equivalent to that of CRA mechanically lined pipes. However, in many cases, considering the overall life cycle cost, CRA mechanically lined pipes are more cost-effective than CRA-clad, solid CRA, or even carbon steel with corrosion inhibitors. This section focuses on the financial advantages of CRA mechanically lined pipes and demonstrates how they can result in significant operational cost savings over the pipeline's design life, challenging the conventional preference for carbon steel pipes. The life cycle cost of pipeline systems typically includes all capital and operating expenditures. Certain costs are incurred regardless of whether carbon steel or CRA mechanically lined pipes are used. However, where costs vary due to corrosion control choices, selecting the right pipeline material can substantially reduce expenses. The life cycle cost calculation involves identifying all cost factors affecting the facility throughout its life. This should include repair and replacement costs, if applicable. By assigning costs to each year of operation, the net present value (NPV) of later-incurred costs can be determined. The total NPV cost gives the life cycle cost, enabling a comparison of all feasible options and allowing the most economical option to be selected. Key factors contributing to the life cycle cost of pipeline systems are discussed below, highlighting why the assumption that the OPEX of carbon steel is equivalent to CRA mechanically lined pipe is inaccurate.

- **Materials**: While CRA mechanically lined pipes typically have higher material costs, in some cases, they can be comparable to carbon steel. For example, a 16" seamless pipe with a 6mm corrosion allowance might cost similarly to a 16" HFI pipe with a 2.5 mm 316L liner.
- **Installation**: Exotic materials like CRA are often more expensive to install, as CRA welding tends to cost more than carbon steel welding.
- **Topside Weight**: Carbon steel systems with corrosion inhibitors require reliable inhibitor injection pumps and tanks, increasing topside weight. This additional weight is not an issue for CRA mechanically lined pipes.
- **Commissioning**: There is no significant cost difference between carbon steel and CRA mechanically lined pipes during commissioning. However, if carbon steel pipes need to be replaced during the system's life, the commissioning cost must be repeated, including lost production during replacement. CRA mechanically lined pipes have a lower likelihood of requiring replacement during the design life of the field.
- **Subsea Umbilicals**: Carbon steel systems with corrosion inhibitors may require a supply boat to deliver chemicals to offshore platforms, which must then be transported to wellhead jackets via subsea umbilicals. These umbilical costs are often overlooked in economic analyses comparing carbon steel and CRA mechanically lined pipes.
- **Operation**: Carbon steel systems incur chemical costs (*e.g.*, inhibitors and biocides), alongside the costs of chemical injection equipment and associated operations. CRA mechanically lined pipes do not require any chemicals throughout their life cycle. For subsea carbon steel pipelines, the cost of chemical injection equipment can be high, as well as the man-hours required to operate the injection facilities. None of these costs apply to CRA mechanically lined pipes.
- **Inspection**: Carbon steel pipelines typically need frequent inspections, such as intelligent pigging, depending on fluid corrosivity, remaining corrosion allowance, pipeline life, and risk assessment. These inspections entail pre-inspection cleaning, intelligent pigging operations, deferred production, and data analysis costs. CRA mechanically lined pipes do not require such inspections.
- **Monitoring**: Carbon steel systems require corrosion monitoring equipment and its ongoing operation. These costs are spread across materials, installation, commissioning, and operation. CRA mechanically lined pipes do not need corrosion monitoring.
- **Maintenance**: The most significant maintenance costs for pipelines relate to operational pigging, particularly for corrosion control. These include the costs of pig purchases, stocking parts, launcher and receiver seals, and pigging operations. For carbon steel systems, pigging costs can be particularly high, especially for subsea pipelines. In contrast, CRA mechanically lined pipes generally do not require operational pigging, though cleaning pigging may be necessary for issues such as wax or scale build-up.
- **Repair and Replacement**: Carbon steel pipes have a higher likelihood of needing repair due to metal loss compared to CRA mechanically lined pipes. Pipeline systems may be designed for partial or complete replacement over their life cycle, and these costs should be included in the life cycle cost analysis. This strategy should be explicitly agreed upon with the operator.
- **Dealing with Design Unknowns**: Carbon steel systems are designed for a specific life expectancy, and if the field’s required life is unclear, a non-corrosive design like CRA mechanically lined pipe may be more appropriate. When production data is poor, conservative assumptions required for carbon steel design may make CRA mechanically lined pipes more attractive.
- **Carbon Tax**: Carbon tax and emissions associated with supply vessels and chemical injection equipment operation (applicable to carbon steel systems) can significantly increase costs. As fields age, maintaining pipeline integrity with inhibitors becomes more challenging, further increasing operational costs. CRA mechanically lined pipes contribute to reducing carbon emissions, aligning with many operators' goals to meet the Paris Agreement by 2050.
- **Corrosion Inhibitor Qualification**: This cost applies only to carbon steel systems, where inhibitor qualification programs may take up to three years to complete.

19. Current and future trends of CRA materials

19.1 Background

CRAs have been a critical component in industries where materials are subjected to harsh environmental conditions, such as the oil and gas, chemical, and power sectors. The need for enhanced corrosion resistance, mechanical strength, and longevity has driven continuous advancements in CRA technology. This section explores the latest trends in CRA material development and offers insights into future directions for enhancing their performance and industrial applications.

19.2 Current trends in CRA development

19.2.1 Material optimization for harsh environments

One of the key trends in CRA development is the optimization of their properties to withstand more aggressive environments. Traditional CRAs such as stainless steel, nickel alloys, and cobalt-chromium alloys continue to dominate, but they are increasingly being tailored for specific applications. For example, nickel-cobalt-tungsten (Ni-Co-W) alloys have emerged as a promising alternative to traditional coatings. These alloys are gaining attention for their excellent mechanical strength, wear resistance, and superior corrosion resistance, particularly in high-temperature and harsh industrial environments. Ni-Co-W alloys combine the beneficial properties of each element. For instance, Nickel (Ni) provides outstanding corrosion resistance, particularly in alkaline and reducing environments. Cobalt (Co) enhances mechanical properties, especially in terms of hardness and wear resistance. Tungsten (W) contributes significantly to high-temperature stability and wear resistance. The synergy between these elements makes Ni-Co-W alloys particularly well-suited for applications such as aerospace, energy, and industrial components, where high durability under extreme conditions is essential. Furthermore, new variations of Ni-Co-W alloys are being tested for enhanced resistance to chloride-induced corrosion, targeting their use in seawater environments. Additionally, Ni-Co-W alloys are being explored as potential replacements for chromium-based coatings, addressing environmental concerns linked to chromium toxicity. While Ni-Co-W alloys are weldable, special welding procedures are required to maintain their properties, such as controlling heat input and cooling rates to prevent cracking and brittleness in the weld zone.

19.2.2 Manufacturing process enhancements

Advances in manufacturing technologies, such as precision electrodeposition and thermomechanical treatments, are driving the optimization of CRAs. These processes enable the fine-tuning of microstructures, which in turn improves the alloys' resistance to localized corrosion and stress-corrosion cracking. For instance, innovative heat treatments are being adopted to enhance the pitting resistance equivalent number (PREN) of duplex and super duplex stainless steel. Furthermore, the ability to control surface treatments and compositions enhances the alloys' overall electrochemical performance.

19.2.3 Sustainability and toxic metal replacement

With increased awareness of environmental and health concerns, researchers are exploring alternatives to CRAs that contain toxic elements, such as chromium. Efforts to replace chromium-based coatings with more environmentally friendly alternatives, like Ni-Co-W alloys and other high-performance non-toxic coatings, are gaining traction. These materials offer improved sustainability without compromising on the required protective qualities for industrial use. In particular, the use of recycled alloy materials is being investigated as a step towards reducing the carbon footprint of CRA production.

19.3 Future trends in CRA materials

19.3.1 Development of high-performance alloy systems

The future of CRA materials is likely to see the rise of hybrid alloy systems that integrate nanotechnology and composite materials. These hybrid CRAs will offer superior corrosion resistance and mechanical properties through the incorporation of nanostructured phases that can enhance the alloy's durability, particularly in extreme conditions. Advances in metallurgical processes will allow for the precise design of such materials, paving the way for their widespread adoption in sectors like deepwater drilling and nuclear energy. Moreover, new composites that combine CRAs with carbon-based reinforcements are being evaluated for their ability to reduce weight while maintaining high strength.

19.3.2 Smart alloys and self-healing materials

A significant frontier in CRA research is the development of self-healing alloys that can autonomously repair minor corrosion damage. Smart materials with responsive behaviors are being explored, including alloys that can detect early corrosion damage and activate healing mechanisms that restore the material’s integrity. This trend could dramatically reduce maintenance costs and extend the operational life of critical infrastructure. Experimental studies are now focusing on embedding microencapsulated corrosion inhibitors within CRA matrices to facilitate self-healing.

19.3.3 Alloys for additive manufacturing

With the rapid rise of additive manufacturing (AM), there is growing interest in developing CRA materials that are specifically optimized for 3D printing. These materials must retain their superior corrosion resistance and mechanical properties even when processed through AM methods, which involve high heat and rapid cooling. Alloy systems that are highly customizable during the AM process will offer new possibilities in industries requiring complex geometries and rapid production times, such as aerospace and medical implants. For example, laser powder bed fusion is being used to create high-performance CRA components with reduced residual stresses.

19.3.4 Evolution of CRA material

While environmental regulations are pushing for reductions in the use of toxic elements like chromium in CRAs, it is unlikely that these materials will phase out completely. Instead, CRAs will evolve through the development of more eco-friendly formulations and enhanced performance characteristics. Newer materials, such as Ni-Co-W alloys, are likely to replace some traditional CRAs, but the demand for highly durable and corrosion-resistant alloys will persist, especially in industries like energy, aerospace, and infrastructure. In addition, advancements in intelligent material design are expected to enable the creation of CRAs with adaptive properties, such as dynamic stress redistribution under load. Furthermore, advancements in smart materials and self-healing technologies will further extend the life and efficiency of CRAs, ensuring their relevance in the future.

20. Conclusion

The selection of preferred CRA material is based on price and weld facility. Alloy surcharges are constantly in flux, and therefore, the comparative prices of duplex and nickel alloys can alter at any time. Manufacturing capabilities would also have an impact. A small quantity of duplex may be easier to procure than clad/liner material. The selection of material should, therefore, be left closer to the time of procurement, *i.e.*, in the detailed design phase. Ease of welding is also a factor in choosing a solid duplex or a clad/liner nickel alloy. There may be great savings in choosing MLP, which is normally easier to weld than duplex. This would need to be addressed during detailed design with input from the installation contractor.

The prime consideration in material selection is internal corrosion, but for solid corrosion-resistant alloys, it is also necessary to consider the risks of external corrosion in seawater and the impact of cathodic protection. The mechanical properties of the material and the effect of welding on corrosion must also be considered. For solid CRA pipe, the CRA, though coated and insulated, may be in external contact with aerated seawater, and there will be a risk of crevice and pitting corrosion and chloride stress corrosion cracking. External corrosion and embrittlement would not occur if the solid CRA pipe were enclosed within a carbon steel pipeline as a pipe-in-pipe configuration. For example, a pipe-in-pipe configuration was used for the BP Rhum HPHT flowline to permit the use of a CRA material that was not suitable for direct contact with seawater at operating conditions. Clad/Lined pipelines present a carbon steel surface to the seawater; carbon steel is readily protected by the combination of conventional coatings and cathodic protection.

An important mechanical issue related to materials selection is the reduction of the yield strength of the solid CRAs at high operational temperatures. Duplex and super duplex steels show a significant reduction in yield strength. For mechanically clad/lined pipe the interaction between the CRA lining and the carbon steel outer pipe needs to be considered because austenitic CRA materials have a higher expansion coefficient than carbon steel. This is, however, expected to have a beneficial effect as the CRA material will be in compression reducing the risk of chloride stress cracking. CRA mechanically lined pipe can eliminate many OPEX-involved costs. The asset owner within any organisation should guide the project team to thoroughly consider the life cycle cost of carbon steel, encompassing both CAPEX and OPEX and challenge the assumption that the OPEX cost of carbon steel is equivalent to that of CRA mechanically lined pipe. The cost of the CRA pipelines was competitive with that of inhibited carbon steel pipelines when assessed on a through-life basis. On some occasions, a CRA may have to substitute carbon steel pipes if an incoming law forbidding the dumping of corrosion inhibitors means that economically it is cheaper to use CRA than provide inhibitor separation facilities.

Conflict of Interest

There is no conflict of interest.

Supporting Information

Not applicable.

Abbreviation	Meaning
AM	Additive Manufacturing
API	American Petroleum Institute
ASTM	American Society for Testing Materials
CAPEX	Capital Expenditures
CP	Cathodic Protection
CPT	Critical Pitting Temperature
CRA	Corrosion-Resistant Alloy
CSCC	Chloride Stress Corrosion Cracking
DNV	Det Norsk Veritas
DPI	Dye Penetrant Inspection
DSS	Duplex Stainless Steel
HAZ	Heat Affected Zone
HISC	Hydrogen-Induced Stress Cracking
HPHT	High-Pressure High-Temperature
ISO	International Standards Organisation
MEG	Mono-Ethylene Glycol
NACE	National Association of Corrosion Engineers
NORSOK	Norwegian Standards Institute
OPEX	Operational Expenditures
PREN	Pitting Resistance Number
QA/QC	Quality Assurance /Quality Control
RBA	Risk-Based Assessment
RP	Recommended Practice
SDSS	Super Duplex Stainless Steel
SRB	Sulphate-Reducing Bacteria
SSC	Sulphide Stress Cracking
SSCE	Silver-Silver Chloride Electrode
YS	Yield Strength (generally as MPa unless stated otherwise)
13Cr	Martensitic Stainless Steel containing 13% chromium

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