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Engaging Degradation Mechanisms Of Materials In A Tourney. An Investigation Into The Philosophy Of Material Selection as a Mitigating Measure and Strategy

by

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Abstract

The aim of this project is to compare some important factors such as safety and environmental aspects, life cycle costing, reliability, availability and fabrication for selecting materials for flowlines for comparative study between carbon steel as a current practice with respect to various corrosion resistance alloys as an alternatives. In order to do that it is necessary to address all possible degradation mechanisms and the conditions that intensify the degradation process with respect to different types of materials like carbon steel, 316 stainless steel, 6MO stainless steel, Duplex stainless steel and titanium in the upstream production flowlines. The guidance has been supplemented with practical examples and descriptions of how the degradation mitigation measures can be applied to control the major threats experienced within the industry. Even though oil and gas industries have implemented mitigation measures to reduce the level of degradation, still it is considered to be one of the major problems. Therefore it is necessary to analyze the protection measures are effective enough with the current material quality. This study examines the degradation issues affecting the offshore pipelines in the North Sea and evaluating important factors, which is identified from the experience of the various authors and their companies.

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1. INTRODUCTION AND BACKGROUND

Oil and gas industry generally will face many challenges to discover, explore and exploit hydrocarbon reserves. In order to meet market demands companies drive to find more reserves by exploring globally in remote areas at greater water depths. In addition to that they are also forced to obtain more output from existing reservoirs by extending the life of facilities and making it capable with greater tolerance. We can foresee that in future there can be chances of having many remote fields on both onshore and offshore with vast accumulating systems which will bring raw fluids into centralized facilities where to be processed and transported to export systems.

Offshore industry not only provide challenge to the engineers who design the structures which operates in hostile environments but also in defining systems that assist in protecting those structures from the atmospheric conditions that are most destructive to those structures. During the initial stages of designing an Integrity Management Planning program, identification of degradation mechanisms that are possible in the offshore process systems is the vital thing to be carried out. Therefore it is most fundamental to understand the relevant mechanisms, their likelihood of occurring in the offshore systems, and the impact that they may have on it. Huge investments are directed towards exploration and production of offshore oil and gas in remote fields. Therefore cost of protecting the structures cannot be compromised by poorly designed applied protective systems. This tendency results in numerous challenges to the capital cost (CAPEX) and operating cost (OPEX) of projects. Due to the complexity of the topsides processes, piping comprises a significant part of the general project costs (CAPEX/OPEX). The material selection can be optimized based on a good understanding of the corrosion mechanisms and the fluid partitioning through the production systems.

Variations in national standards, legislative prerequisites, operator procedures and risk tolerance also play a generous role in the materials selection process. These challenges need diverse methodologies to pipelines materials selection, which may strongly fluctuate between various nations and operators. While carbon steel pipelines still be choice for most of the pipelines designed, but now there is a increased tendency towards the use of corrosion resistant alloy (CRA) and flexible pipelines within the European sector, which is determined and driven by the use of full life cycle instead of CAPEX evaluation and the standards used.

1.1 PROBLEM FORMULATION

The material selection for a flowline obliges a trade-off between optimum corrosion resistance, safety, mechanical properties, fabricability, reliability, availability and cost. It might regularly be the situation that a last decision must be made between two or more alternative materials which might contrast in the degree to which they meet all the desired service prerequisites for the expected obliged lifetime of the project. In the compelling situations where corrosion risks are either negligible or exceptionally intense, materials selection is generally between carbon steel or corrosion resistant alloy respectively.

Corrosion problem have been concerned for many decades hence they are the causes of failure in equipment and structure made of metal. These corrosion problems are normally found in pipelines, storage vessels and other equipment's like tubing, casing, valves and wellheads which have to operate with corrosive materials. Many researches and studies have been going on since this problem has large effect on operation. It is necessary to select the material with respect to the operating conditions and degradation mechanisms related to it. Various models have been formulated to predict accurate corrosion mechanisms. The main aim is not only to understand the phenomenon, but also to formulate effective mitigation measure. Therefore, it is more important to know the type of mitigation or protection approaches that can be used against the various degradation mechanisms present in the actual process system.

To carry out in-service inspection program it is more important to know the material properties, operation conditions, environmental conditions and maintenance properties that pave ways to promote degradation of materials. Degradation can occur due to Mechanical causes, chemical causes and induction by heat and other forms of energy. Some common types of degradation mechanisms are Corrosion, Erosion, Fatigue, Hydrogen related Cracking, wear, overload, temperature expansion and contraction etc. These mechanisms and their causes should be analyzed in detail under various operation conditions.

Material selection for pipelines is one of the most critical decisions to be taken in the early project cycle of pipework in oil and gas production systems. It has direct leverage on capital cost, operation needs, inspection and maintenance strategy. In future there will be need for exploiting oil from more challenging environments from both geographical and chemistry perspectives. Hence there will be a situation to make a productive decision in material selection with respect to risk and operational necessities. Carbon steel with corrosion inhibitor was chosen for numerous projects because of smaller capital costs. Selecting corrosion resistant alloy will considerably increase the capital cost. The material selection process involves in diverse steps to identify the best apt material by investigating the cost, the degradation mechanisms, risks and required inhibitors, etc.

Using carbon steel in current practices, chemical protection believed to be one of the effective protections. This thesis mainly discusses about whether carbon steel with chemical protection is truly an effective or alternative corrosion resistant alloys are effective in terms of various factors. Problems related to current chemical injection systems are taken into account to analyze more with compared to use of CRA alloys.

1.2 MAIN OBJECTIVES AND SUB OBJECTIVES

Main Objectives:

- Explore and understand the fundamental phenomena and technical aspects of the process of degradation of materials used in flowlines.
- Investigate and narrow down the key and potent conditions/technical parameters that form the basis or serve as a root cause for the process of degradation.
- Map and analyze the effects of influential operational conditions such as pressure, temperature, flow rate etc. on the characteristics, properties and performance of the material.
- Understand, investigate and exemplify the current industrial practices used by the operators in offshore flowlines.
- Discuss the mitigation measures to overcome the process of degradation.
- Evaluate the characteristics of corrosion resistant alloys.
- Identify and discuss about various factors for comparing the alternatives (Corrosion resistant alloys).
- Investigate, discuss and contemplate the impact by comparing the alternatives with respect to current practices.

PROJECT ACTIVITIES LINK TO EACH SUB-OBJECTIVE AND RESEARCH METHODS:

- Collect and understand the degradation mechanisms of materials in offshore flowlines systems through literature survey and experiences gathered from various operators in Norwegian continental shelf
- Understand and systematically compile the current mitigation measures used by the operators of NCS.
- Gather and compare the alternatives with respect to current practices in terms of cost, safety, reliability, availability and fabrication.
- Brainstorm on the collected information to derive a logical and technically feasible material as a solution to counter the degrading mechanisms with respect to various factors.

1.3 LIMITATIONS

- Limited materials and equipment's are considered in this thesis.
- Mainly focussed on flowlines compared to other equipment's.
- Data mostly obtained from Norwegian Continental shelf.
- Hard to cover all aspects of the topic within time limit.

2. DEGRADATION MECHANISMS OF OFFSHORE FLOWLINES

All materials are subjugated to various mechanical and environmental factors during their use. Those various factors are mechanical vibration, mechanical loads, chemical attacks, process conditions like temperature, pressure etc. Under these various influencing factors materials loss their potential which develops develop degradation. Degradation may leads to catastrophes if not mitigated or monitored properly. Corrosion and erosion are the two main degradation mechanisms which is a big threat in oil & gas industries. If you take offshore process systems equipment's, in production casings, sand production causes erosion and produced water & water injection causes corrosion. Corrosion, fatigue and mechanical wear are the common problems that occur in drilling equipment's. This paper mainly focuses on corrosion and erosion degradation and mitigation measures in offshore pipelines.

2.1 CORROSION

Corrosion can be defined in different ways, but generally Corrosion is a process of deterioration of materials by chemical interaction with their environment. The word "corrosion" is sometimes also referred to the degradation of plastics, concrete and wood, but generally relates to metals.

Corrosion in metallic materials can be divided into three groups,

- Wet corrosion – Electrochemical process where corrosive environment is water
- Dry corrosion – Chemical corrosion where corrosive environment is dry gas
- Corrosion in fluids like fused salts and molten metals.

Corrosion leads to

- Reduced metal strength
- Failure of equipment
- Leakage of fluids
- Changes in the surface properties

2.1.1 ATMOSPHERIC CORROSION

Atmospheric corrosion depends upon the environmental conditions. For example, in atmospheric corrosion, the electrolyte is moisture from precipitation, fog or dew etc. There are some main factors which have more influence on the corrosivity of the atmosphere. They are

- Surface exposed for long time in wet conditions
- The atmospheric pollutants that hits the surface
- Chlorides from sea that reaches surface

Due to the presence of excess oxygen in the atmosphere, the corrosion continues rapidly if electrolyte is present.

2.1.2 GALVANIC CORROSION

Galvanic corrosion is also called bimetallic corrosion. It is a localized corrosion mechanism which metals can be corroded preferentially. If different types of metals with different compositions are plunged in a corrosive solution, each will produce a corrosion potential. If the corrosion potential of those different metals is different then they are in the direct contact and immersed in an electrolyte, the more noble metal will become cathode and more active metal will become anode. The corrosion rate mainly depends on the anode cathode surface area which is exposed to the electrolyte. Quantifying current will flow between cathode and anode. The corrosion percentage of anode will be increased and cathode will get decreased. Galvanic corrosion is nothing but the increased corrosion of the anode. Galvanic corrosion will happen when (i) Dissimilar metals come in contact (ii) Metal to metal contact and (iii) Metals on the electrolyte.

In case of unavoidable situation using two different metals the following measures can be used to decrease the damage they are, selection of material which are close together in electromotive force series, orientation of anode-cathode area ratio, Introduction of third metal using cathodic protection.

Some anodic materials are Magnesium, Zinc, Galvanized Steel, Aluminum, Mild Steel, Low Alloy Steel and Cast Iron. Cathodic materials are Lead, Tin, Muntz Metal, Yellow Brass, Aluminum Bronze, Red Brass, Copper Alloy 400, Stainless Steel (430), Stainless Steel (304), Stainless Steel (316), Silver and Gold. Figure show below provides overview about galvanic corrosion.

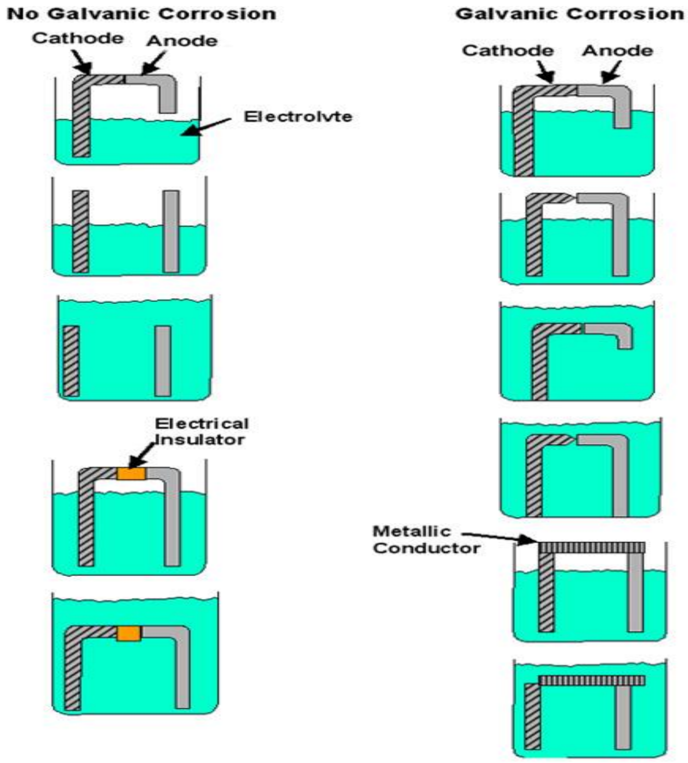


Figure 1: Galvanic Corrosion

(Source – from http://www.ssina.com/corrosion/galvanic.html)

2.1.3 CUI CORROSION (CORROSION UNDER INSULATION)

Corrosion under insulation is a localized form of external corrosion in a severe form. It is considered to be one of the big threats in oil & gas industries. This type of corrosion will occur when the water intrudes into insulation. The difficult part in this is it's too late to find the visible evidence as corrosion problem hidden inside with insulation acting as mask. Selection of proper insulation, Equipment design, protective paints & coatings, weather barriers and scheduled maintenance practices are the most important factors to be focused in preventing corrosion under insulation.

2.1.4 MIC (MICROBIOLOGICALLY INDUCED CORROSION)

Microbiologically induced corrosion is also called bio corrosion. It refers to the influence of living microorganisms such as bacteria, algae or fungus which are engaged in promoting deterioration of metallic and nonmetallic materials. Aqueous environments are more prone to MIC, because the microorganism will grow when water is always present or if there is stagnant and low flow conditions. It happens in two processes; the formation of corrosion cells on the surface of metal creates sticky biofilms. The parameters such as concentration of dissolved oxygen, salts, pH value, organic and inorganic compounds are influenced by microorganisms at growing interface. The other process is by direct attack of chemicals. MIC is more common in heat exchangers, storage tanks and piping's with slow flow conditions.

2.1.5 CREVICE CORROSION

It is form of localized corrosion which occurs in similar conditions as pitting. Crevice corrosion takes place due to the concentration difference between two regions of same metal components. It occurs in the locale that has lower concentration. Generally the attacks will be at flange joints and threaded connections. Proper care should be taken in concentration difference in order to nullify this corrosion. For example instead opting riveting, welding can be chosen.

2.1.6 CAUSTIC CORROSION

The Exposure of concentrated caustic on metal surface permits to dissolve the protective Fe_3O_4 layer causing metal loss which leads to form cracks in piping's and other equipment's. Caustic corrosion is also called as a form of stress corrosion cracking. Carbon steel and low alloy steels are more sensitive whereas nickel base alloys are more resistant to caustic corrosion.

2.1.7 EROSION CORROSION

Erosion-corrosion is defined as induction of corrosion attack in the metals due to the relative motion of corrosive fluid and surface of the metal. Mechanical wear and chemical attack's combination is the main reason behind erosion-corrosion mechanism. Metals are more prostrate to this degradation mechanism. It has detrimental effect on metal that passivate and forms secure film.

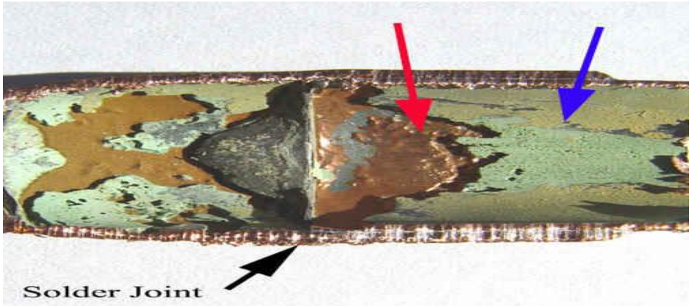


Figure 2: example of turbulence induced erosion near a solder joint

(Source- Charles C. Roberts fromhttp://www.croberts.com/erosion-corrosion.htm*)*

The blue arrow shown in figure 4 is the passive film protecting the copper pipe. Eroded pipe material caused by high water velocity due to water turbulence, shown by red arrows, as the water flows from left to right in the figure 4. In this case, there is no evidence as the water leakage occurred suddenly and without warning. Figure 5 showing the turbulence mechanism of erosion-corrosion that was observed in Figure 4. The turbulent flow of water increases the velocity near the pipe surface, wiping the passive protective film which accelerates the corrosion mechanism.

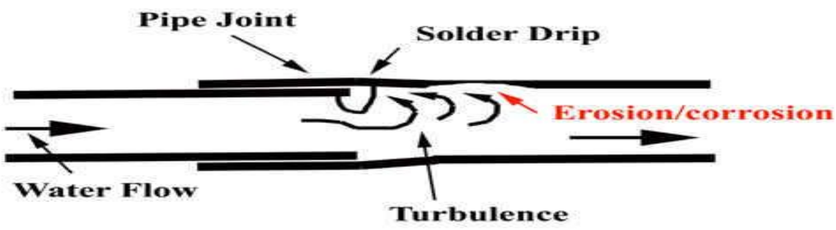


Figure 3: Turbulence mechanism of corrosion

(Source- Charles C. Roberts from[*http://www.croberts.com/erosion-corrosion.htm*](http://www.croberts.com/erosion-corrosion.htm)*)*

2.1.8 PITTING CORROSION

Pitting corrosion is nothing but the formation of small pits and holes or spots on the surface of the steel. This type is also a localized form of corrosion. Neutral or acidic solutions containing chlorides or halides are main culprits for the formation of pitting corrosion. This type of corrosion is highly dangerous as it is difficult to detect until the failure of components. Monitoring is also bit difficult, therefore proper care and maintenance like polishing the surfaces should be done on regular basis.

Figure 4: Pitting corrosion

(Source-Cato Torgersen, 2012)

2.1.9 INTER-GRANULAR CORROSION

The cause for Inter granular corrosion is similar as crevice corrosion i.e due to concentration difference, but here it occurs along the grain boundaries. Those boundaries are highly sensitive to corrosion. This type of corrosion happens severely on stainless steels. In order to protect from this corrosion remedies like possible heat treatments, reducing the carbon content, increase the alloying elements which readily form of carbides can be suggested.

2.1.10 SELECTIVE LEACHING

Selective leaching is a process of dismissal of an element from solid alloy by corrosion process. Dezincification i.e. the removal of zinc from brass alloys is the most common example of selective leaching. Similarly dealuminification loss of aluminum, decobaltification loss of cobalt, iron from cast iron, and nickel from steel alloys can also occur. Consequence of this type of corrosion is the mechanical properties of the materials are damaged as it becomes porous. The material can be protected by using cathodic protection and change of environment.

2.1.11 STRESS CORROSION CRACKING

Crack development in a corrosive environment is called as stress corrosion cracking. This type of corrosion will happen due to combined action of tensile stress that leads to unexpected sudden failures. The mitigation measures to be taken for this type is to avoid the external stress, Maintain coatings, Avoid salt deposits on hot vessels or pipes, inhibition, avoid wet insulation and change in type of alloy when there is change in stress level.

Figure 5: Stress corrosion cracking

(Source-Cato Torgersen, 2012)

Figure 6: Stress corrosion cracking

(Source-Cato Torgersen, 2012)

2.2 EROSION

Due to mechanical action the material from the surface of the pipe will be removed, often by impinging fluid, attrition by slurry, particles suspended in fast moving fluid or gas, is called Erosion. Internal erosion is especially very dangerous because there may be no external witness. The erosion rate depends upon the piping material, velocity of fluid and fluid type.

The blue arrow shown in the figure 6 is with normal piping wall thickness. The red arrow shown is an excessively less wall area where leaks had occurred. This reduction of the pipe wall in new installations is characteristic of the phenomenon called erosion. Due to turbulence and excessive flow rate, the passive corrosion protective film has been removed in those red pointed areas, causing accelerated erosion of the pipe wall, reduction of the pipe wall and hence water leakage.

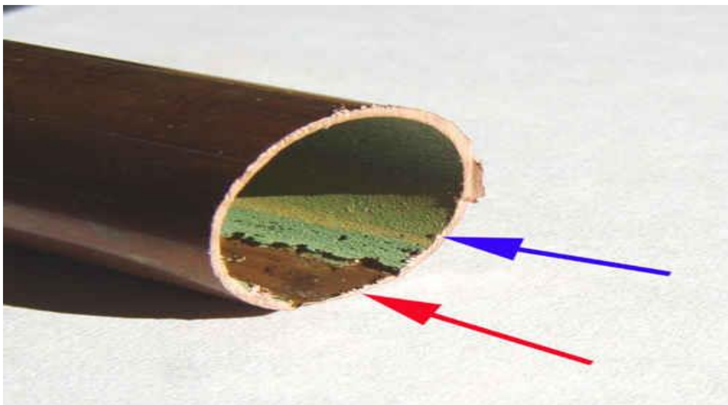


Figure 7: Showing the view of a section of the eroded interior pipe surfaces

(Source- Charles C. Roberts fromhttp://www.croberts.com/erosion-corrosion.htm)

2.3 CAVITATION

The formation of vapor cavities, which means bubbles or voids in the liquid is termed as Cavitation. The force acting on the liquid causes bubble formation. Rapid pressure change leads to the formation of cavities where low pressure occurs. In case of high pressure the voids implode and create an intense shockwave. Cavitation is common in valves, pumps, turbines.

2.4 WEAR

Loss of material or loss of material integrity from the surface of pipe due to erosion and corrosion is called wear, erosive wear due to particle and droplet impingement.

2.5 THERMAL FATIGUE

When the temperature is high, high axial load will be created. If this situation is not considered during design, it can lead to unwanted convulsion or lateral buckling within the pipelines. “Thermal fatigue” is the main cause which happens due to difference in temperature within the pipelines. The operating temperatures ranges from -200^{0}C and +800^{o}C. The process of expansion and constrainment happening concurrently causes thermal stress which over some period of time leads to fatigue failure. This failure mode causes severe damage to piping that result in dangerous situations.

The thermal fatigue problems can overcome by implementing thermal management philosophy. The pipeline routing must be done in such a way that the pipe has inherent flexibility in its geometry (like snake lay) so that the thermal stresses due to expansion of pipes is reduced. The flexibility shall be provided to such an extent considering other effects like pressure drop and increase in cost.

2.6 HYDROGEN RELATED CRACKING

Hydrogen cracking also named as cold or delayed cracking. This type of crack occurs in ferritic weldable steels. It occurs immediately on welding or after some time. There are three main causes for the hydrogen cracking. They are hydrogen generation from the contamination of the weld area and by welding process, Brittle structure suspicious to crack and Residual tensile stress acting on weld joints.

2.7 ICE AND HYDRATE FORMATION

Ice and hydrate formation occurs due to flow assurance problems. Ice and hydrate formation prevention is considered to be in high priority because the removal is very complicated. The one way of solving the flow assurance problem can be done by traditional approach of system selection for prevention and remediation that combines sampling, laboratory techniques and predictive modelling. The techniques that support continuous flow assurance also benefit effective reservoir management and production optimization. More permanent solution can be done through systematic data gathering and trends affecting flow efficiency be identified and mitigating prognoses be developed. Combination of chemical treatment (injecting Mono ethylene glycol) and thermal insulation should be used to prevent the hydrate and ice formation.

3. CORROSION IN OFFSHORE PROCESS SYSTEMS

Corrosion in offshore platforms and production facilities is one of the biggest challenges, both on terms of equipment repair or replacement cost and in terms of pollutions likely due to the chemical treatments to control corrosion. Carbon dioxide, hydrogen sulphide and free water are the main cause for corrosion in offshore process systems. Offshore rigid and flexible pipelines and risers are more prone to corrosion issues. Corrosion in these flowlines and process facilities can seriously disrupt the production and safety issues to offshore personnel. Despite of advances in systems, failures still happens from different kinds of failure modes.

3.1 INTERNAL CORROSION

We can categorize the occurrence of internal corrosion in water injection pipelines, oil & gas production pipelines and oil & gas transport pipelines.

3.1.1 WATER INJECTION PIPELINES

The two mechanisms which often cause internal corrosion in water injection pipelines are oxygen corrosion from poor de-aeration and microbial influenced corrosion from poor hydro chlorite & biociding treatment. If you take North Sea, failure of water injection pipelines are common. Marsh, Duncan, Kenny & Ian (2009) made comparison from the experience of pipelines where oxygen control has been poor and microbial control has been effective, and pipelines where microbial control has not been effective. They found one field where the oxygen control is not so effective, but the pipeline microbial corrosion control has good results with batch biociding and regular pigging. That field has been operated for 30 years and more with only some lesser extent of problems from their water injection lines. But there are other fields where microbial control has been worse.

O2 Corrosion

O_2 corrosion is common around the water injection and seawater systems. The chemical reaction of O2 corrosion is given below:

$$6Fe + 3O_2 + 6H_2O \rightarrow 6Fe(OH)_2.$$

The ferrous oxide oxides further into $Fe(OH)_3$ by the usage of O_2 in the water. When $Fe(OH)_3$ reacts to rust by:

$$Fe(OH)_3 \rightarrow Fe_2O_3 + 3H_2O$$

Thus the corrosion rate is limited primarily by the oxygen content, temperature and water quality. The temperature will increase the reaction rate, but even in low temperature systems, all O2 will eventually be used in a corrosion process.

3.1.2 OIL & GAS PRODUCTION PIPELINES

Co_2 Corrosion

In production pipelines Co_2 corrosion is the most common type corrosion issue. It is also called as sweet corrosion. The main reason behind this because of the presence Co_2 content in the crude oil and gas obtained from the reservoir. The hydration of dissolved carbon dioxide gives carbonic acid, carbonic acid then dissociates into bicarbonate and carbonate, and those chemical reactions are given below. The pH level reduces due to the carbonic acid which leads to corrosive pipelines.

$$CO_{2\,(g)} \longrightarrow CO_{2\,(aq)}$$

$$CO_2 + H_2O \longrightarrow H_2CO_3 \text{ (Carbonic acid)}$$

$$H_2CO_3 \longrightarrow H^+ + HCO_3^-$$

$$HCO_3^- \longrightarrow H^+ + CO_3^{2-}$$

The electrochemical reaction of carbon dioxide corrosion is

$$Fe + CO_2 + H_2O \longrightarrow FeCO_3 + H_2$$

The formations of surface films, consists to iron carbonate ($FeCO_3$) and their effects on the corrosion rate has significant role in $CO_{2\,(aq)}$. Iron carbonate ($FeCO_3$) mainly depends upon temperature and it plays an important role in formation of protective layer on the surface of the metal at higher temperature.

Carbon dioxide corrosion is greatly influenced by following factors, they are temperature, CO_2 partial pressure, flow rate, pH, acetic acid concentration, water wetting, welds (metal microstructure) etc. These factors are closely linked with each other. Their influence is not yet completely understood.

For example, let's consider temperature as 80^0C, pressure 2 bar, flow rate 4 m/s and pH 5.0 are kept constant; the amount of water phase varied, then say the corrosion rate ranges from < 1-20 mm per year. But this can change in the properties of thin layer lines. Therefore layer can also have effect which has interaction. Inhibitor plays an important role in this. When the corrosion inhibitor availability is maintained, it is possible to have some corrosion control on the pipelines. The major problem is lack of systematic dosing of corrosion inhibitor. When the pipelines have attained a stage of beyond their lifetime, to maintain the wall thickness it may need high corrosion inhibitor in the future. Operator's cooperation and efforts are needed to achieve more control on this issue.

H_2S Corrosion

The natural gas can be corrosive due to the significant content of hydrogen sulfide. Natural gas is said to be "sour gas" if it contains more than 5.7 milligrams of hydrogen sulfide per cubic meter of natural gas. Natural gas with less amount of hydrogen sulfide is called as "sweet gas". Sour gas at high temperature, pressure and in mixtures of formic acids which typically found in downhole oil well simulations will be more corrosive. Only special surface alloys can withstand to that sour gas environments. Amine solutions are generally used to remove hydrogen sulfide gas. H_2S Corrosion is electrochemical in nature. The chemical reaction happens between H_2S and iron form iron sulfide films. H2S is non-corrosive in the absence of water.

$$Fe + H_2S + H_2O \longrightarrow FeS + H_2$$

Depending upon the environment, hydrogen sulfide can form various types of iron sulfide form like amorphous ferrous sulfide, cubic ferrous sulfide, pyrrhotite, troilite etc. Finding the kinetics of iron sulfide scale formation is difficult because of its close influences and poor understanding of mechanisms.

3.1.3 OIL & GAS TRANSPORT PIPELINES

In transport pipelines, we can categorize the pipelines into four divisions depending upon the composition of fluids that are transported. They are

- Dry gas pipelines – Transports gas with dew point less than 40^{o}F
- Wet gas pipelines – Transports gas with dew point more than 40^{0}F
- Low water- cut oil pipelines – Transport oil with less than 20% water
- High water - cut oil pipelines – Transport oil with more than 20% water.

In these categories, the more critical lines which need continuous corrosion inhibitors are wet gas and high water cut oil pipelines.

3.2 EXTERNAL CORROSION

In external corrosion the main areas to be pertained are corrosion under insulation (CUI), firewater and deluge systems, flanges and bolts, valves, pipe supports and pipe coatings, and threaded plugs. Anode depletion and coating degradation are the major problems in external corrosion. Pipelines are usually coated to provide protection from the surrounding environment. The role of coating the structures is to act as physical and dielectric barrier. Cathodic protection helps to protect and reduce the corrosion rate to negligible level.

3.2.1 Anode depletion

When the pipelines become older, the external corrosion of anode depletion forms below the water line. Anode depletion considered as integrity threat after operating 30 years and more. Many offshore structures need cathodic protection retrofits in next decades to protect the structures. Many risers and spool piece anodes got depleted in excess of 75%. Pipelines anode gives more wastage, mainly near pipeline ends.

3.2.2 COATING DEGRADATION

In spite of the fact that best endeavors are put by the coating technologists, the coating won't be available everlastingly. Even in undisturbed situations, Painted pipelines exposed to North Sea environment is unlikely to last more than 10 years. The defects in painting cause blisters because of contaminations of salt or disbonding due to paint applied in less ideal situations. Therefore the paint systems result in coating degradation which it does not last until design life.

Figure 8: Coating Degradation

(Source-Jonathan Marsh and Phil Duncan, J P Kenny and Ionik consulting, and Ian Macleod, MCS, 2009)

4. CURRENT PRACTICES OR CURRENT USAGE OF MATERIALS

4.1 INFORMATION ABOUT PLATFORMS AND FLOWLINE MATEIALS

The following information about the current practices of flow line material (TR2000, Statoil) currently used by the oil & Gas NCF

Gullfaks-C

Operator : Statoil

Location : 34/10 in the northern part of the north sea

Production : Oil and Gas

Flowline Material : Carbon steel 5L X52 PSL2 S

Design Parameter : Pressure rating 1500, Pressure range 255.3/226.1, Temperature range 29/150

Statfjord-B

Operator : Statoil

Location : North sea

Production : Oil and Gas

Flowline Material : Carbon steel 5L X52 PSL2 S

Design Parameter : Pressure rating 1500, Pressure range 248.0/219.0, Temperature range 8/121

Troll-A

Operator : Statoil

Location : 34/10 in the northern part of the north sea, 65 km west of kollsnes near Bergen

Production : Gas

Flowline Material : Carbon steel 5L X52 PSL2 S

Design Parameter : Pressure rating 1500, Pressure range 255.3/193.7, Temperature range 46/300

Heidrun

Operator : Statoil

Location : North sea

Production : Oil and Gas

Flowline Material : Carbon steel 5L X52 PSL2 S & Duplex A790 S31803

Design Parameter : Pressure rating 1500, Pressure range 255.3/226.1, Temperature range -29/150

Snorre-A

Operator : Statoil

Location : North sea

Production : Oil and Gas

Flowline Material : 6MO & Super Duplex A790 S32760

Design Parameter : Pressure rating 1500, Pressure range 258.6/256.2, Temperature range -46/110

5. EFFECTS OF CORROSION ON CURRENT USAGE OF MATERIALS

5.1 EFFECTS OF CORROSION AND CONDITIONS ENHANCING CORROSION

The following are various process parameters to be considered to identify the effect of degradation mechanisms. All these following parameters have some kind of influence in enhancing the corrosion rate.

- Temperature
- Pressure
- pH
- Flow rate
- Velocity
- Dew point

Also the following content have some specific influence in increasing the corrosion rate.

- CO2 content
- H2S content
- Oxygen
- Oil, gas & water composition
- Salinity
- Water content
- Sand / Solid particles content
- Dew point
- Wax content

Temperature effect

Generally corrosion rates will increase with increase in temperature. According to De Waard and Milliams, there is a significant increase in the corrosion rate as function of the temperature. Temperature affects corrosion rate of metals in electrolytes primarily through its effect on factors which control the diffusion rate of oxygen. In a closed system, there is no possibility for oxygen to escape, therefore the corrosion rate continue to increase indefinitely. The corrosion rate can increase by doubling the rate for each 10^{o}C rise of temperature, sometimes this dissolution leads to common attack or cracking. By avoiding unnecessary high temperature, corrosion formation level will be reduced.

Effect of Pressure

During the well depletion process, carbon dioxide and water are injected for enhancing oil recovery. This method helps to maintain the pressure in the reservoir. Under higher partial pressure, occurrence of pitting corrosion can obvious, where morphology was different from that formed at low temperature. Earlier experiments have proved that the temperature and partial pressure will directly affects the morphology and composition of corrosion products, which in turn caused the change of corrosion rate and occurrence of localized corrosion. The corrosion rate increases at a high rate with increase in carbon dioxide partial pressure at each temperature and water cut.

pH effect

Corrosion will generally increase when pH is less than 5. It increases even more if the oxygen enters into the system. H_2S and O_2 combination is particularly tend to be more problematic combination.

Flow rate

Flow rate is an important factor to be considered which affects the corrosion rate and it mainly depends upon various parameters like chemical concentration, type of chemical, process conditions etc. Normally the value will be recommended by the chemical manufacturers. More often it is highly depends upon the process medium and rate of reaction by means of chemical interaction. Injecting the correct level at the recommended dosage rate is more critical. Dosing incorrectly can make unexpected reactions and head to equipment damage which leads to excessive system downtime. In other way, injecting excessive can become even worse added with their assorted costs. To achieve desired flow rate, the chemical injection equipment's should be designed as such to maintain same flow rates even after the initial system calibration.

Velocity

One of the most important factor influencing design and corrosion in process systems is velocity. Due to this impact it is necessary to design the pipe by considering allowable design velocities. Generally local velocities will be different from design velocity. The process system which consists of small features like bends, orifices, valves, flanges that are misaligned etc. can create turbulence which in turn generates high velocities and leads to corrosion acceleration. So it is important that the system design and fabrication should focus on reducing the occurrence of turbulence

5.2 CARBON AND ELEMENT OF LOW STEEL ALLOYS

Generally weathering steels is a class of low alloy structural steels which develops protective layer when exposed to the atmosphere. These low steel alloys do not require painting as these alloys have corrosion protection from the rust layer formation. Therefore it has an advantage of avoiding cost due to painting. The addition of other alloys adds strength to these steels.

Study has been done by Bethlehem Steel Corporation to define the effects of various alloying elements and impurities on the corrosion resistance of low alloy steel. Elements are Phosphorous (P), Sulphur (S), Carbon (C), Manganese (Mn), Silicon (Si), Copper (Cu), Nickel (Ni), Chromium (Cr), Arsenic (As), Molybdenum (Mo), Tin (Sn), Vanadium (V), Tungsten (W), Aluminium (Al), and Cobalt (Co). The concentrations of those elements are shown in table 1. They tend to determine the corrosion loss on the basis of loss of tensile properties. Test specimens are placed on racks which are supported by enamel rods which is inserted through hole at each end of the test specimen. The specimens after exposure were weighed to calculate the mass loss and the tensile tests were also conducted. They found that mass loss is more consistent than the tensile test results after few years of testing. The thickness loss were calculated from mass loss by assuming the density of steel as 7.86 g/cm^2

Maximum Concentrations of Alloying Elements in Test Materials (wt%)

C	Mn	P	S	Si	Ni	Cr	Cu	Al	V	Co	As	Mo	Sn	W
1.5	1.5	0.3	0.3	1.5	1.1	1.1	1.5	1.5	0.5	1.5	0.5	0.5	0.5	0.5

Table 1: Maximum concentrations of alloying elements (wt %)

(Source-H.E. Townsend, 2001)

Set of equations are used to find the corrosion loss.

$$C = AT^B$$

C = Corrosion Loss

T = Time of exposure

A & B are constants

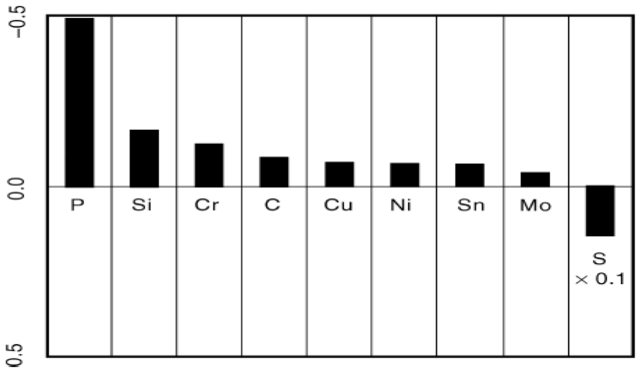


Figure 9: Effect of elements on corrosion losses

(Source-H.E. Townsend, 2001)

Negative value indicates less corrosion. From the results of their experiment it is found that It shows that P, Si, Cr, C, Cu, Ni, Sn and Mo have good corrosion resistance. V, Mn, Al, co, As and W have no significant effect and S has more corrosion losses.

5.3 CARBON STEEL

Carbon steel is the most commonly used material in offshore flowlines. The carbon steel use with inhibitor is still considered to be favourable material when compared to other type of materials like duplex stainless steel, nickel alloys because of the lower cost and high strength. Various researches have been conducted in order to control the corrosion rate of carbon steel by injecting chemicals.

During design of carbon steel pipelines the corrosion allowance of 3mm as per NORSOK standard is generally recommended but however it should be evaluated depending upon the each systems corrosion effects.

Barker, Hu and Neville (2011) conducted an investigation to determine the corrosion rate of carbon steel material in normal condition, heat affected zone and Ni-Molybdenum weld material in the pipework of an offshore facility. The experiment conducted using a submerged impinging jet in CO_2 saturated condition. The compositions of carbon steel parent and weld material is shown in the table below.

Element	Parent Metal	Weld Material
Carbon	0.120	0.200
Silicon	0.210	0.230
Manganese	0.960	1.120
Phosphorus	0.019	0.010

Sulphur	0.003	0.012
Chromium	0.060	0.070
Molybdenum	0.030	0.180
Nickel	0.090	0.780
Aluminium	0.035	<0.010

Table 2: Showing compositions of carbon steel parent and weld material (wt %)

(Source- Richard Barker, Xinming Hu and Anne Neville, 2011)

The test was conducted at flow rate 7 m/s and temperature at 45^0C. The rate has been calculated using linear polarization test with corrosion rate as a function of time. The results found are the static corrosion rate of heat affected zone is around 2.62 mm/year, carbon steel parent material 2.65 mm/year and Weld material is 2.94 mm/year. By comparing the values it's been noticed that the weld material rate is 15% higher when compared with parent and heat affected zone corrosion rate. It's also observed that the protective layer failed to form at temperature 45^0C, as there was no reduction of corrosion rate throughout the experiment duration.

6. MITIGATING MEASURES USED ON CURRENT PRACTICES

6.1 CORROSION & EROSION MITIGATING MEASURES

The offshore process systems have type of equipment's installed which is similar to equipment installed onshore but in limited space. As each square meter of offshore platform is expensive, the equipment's will be placed very compactly. This compactness makes difficulty in corrosion monitoring. The reasons are:

- Piping's with smaller radius and more bends
- Difficulty in painting the system
- Limited accessibility for inspection and repairing of components

By considering above factors it is better to take account of these factors in the design stage in order to control the corrosion rate. There are many ways to organize and operate successful corrosion management systems in the following phases

a. Design Phase:

- Materials with excellent corrosion resistance properties shall be recommended to be used in design specifications.
- Design allowances shall be considered to compensate material loss due to corrosion.
- Passive Corrosion protection systems like cathodic protection shall be installed.
- Use of dissimilar materials shall be avoided to prevent galvanic erosion.

b. Operation & Maintenance phase:

- Corrosion resistance coatings shall be applied at regular intervals as recommended in maintenance schedule.
- Corrosion monitoring shall be done regularly to study the rate of material loss in the pipeline.
- Fluid properties like acidity shall be checked at regular intervals.

Erosion control:

Choke valve is an important component which helps to control the production rate of the well. By seeing the choke valve disc, amount the erosion can be identified. There is some prevention methods available to reduce erosion include improving the flow lines within the pipe, smoothing out irregularities, allowing elbows to have larger angles, and changing pipe diameters gradually rather than sharp changes. Other methods include reducing turbulence by slowing the flow rate, changing the pH, reducing the amount of dissolved oxygen, and changing the pipe material to a different metal or alloy. The figure below shown is leaking due to erosion. (A) Showing the occurrence of likelihood places for leaks. (B) Redesigned the piping system to eliminate or reduce erosion. The pictures shown below are some good examples of pipes that are designed to reduce erosion

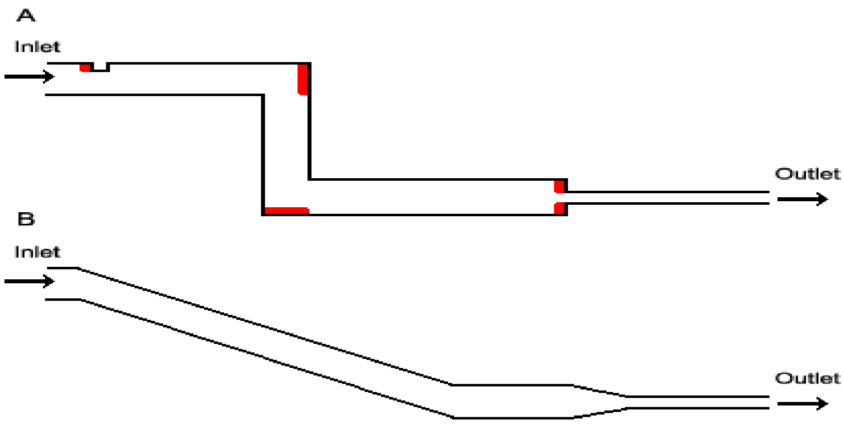


Figure 10: Shows design of pipe due to Erosion

(Source- Charles C. Roberts from[*http://www.croberts.com/erosion-corrosion.htm*](http://www.croberts.com/erosion-corrosion.htm)*)*

Figure 11: Shows design of pipe due to Erosion

(Source- Charles C. Roberts from[*http://www.croberts.com/erosion-corrosion.htm*](http://www.croberts.com/erosion-corrosion.htm)*)*

Typically erosion monitoring is carried out by applying weight loss coupons or ER probes of stainless steel, with similar mechanical properties as for the pipe that is the subject for monitoring. Hence the erosion probes will not corrode and all material loss and can then be attributed to erosion.

6.2 INSPECTION & MONITORING

Inspection and monitoring is an important philosophy which has to be carried out to ensure safe and reliable operation. Assessing risk and formulate proper inspection and mitigation measures are considered to be vital part of asset integrity management. Service inspections are made to achieve asset integrity management of static process equipment. It will be helpful to advice an operator when there is a need for maintenance using the data from service inspection. However some of the systems information in most of the time is unreliable or not enough which limits the application of many software systems.

The purpose of inspection is to prevent, predict and detect the syptoms of failures and discharges due to degradation mechanisms. Inspections should be done on regular basis by qualified personnel. Some of the activities involved in scheduled inspections are an external visual inspection of pipelines, Non destructive test to evaluate integrity of pipelines, thickness measurement and some additional assessment when needed.

6.3 PRINCIPLES FOR MATERIALS SELECTION

There are some important factors that has to be considered during the selection of material grades in order to achieve some degree of protection, they are

- Mechanical properties of the material
- Temperature resistance
- Properties of internal fluid
- Resistance level of corrosion effects
- Installation methods and procedure
- Weight requirement
- Weld ability
- Fatigue and fracture resistance
- Surrounding atmospheric and loading conditions

6.4 DESIGN LIMITATIONS

According to NORSOK M-001, Carbon and low alloy should have minimum design temperature -46^{o}C for pressure retaining purposes. The sour service design limitations for corrosion resistant alloys are given in table below.

Material	Chloride concentration, max. (%)	Min. allowed in-situ pH	Temperature, max. (°C)	Partial pressure H_2S, max.
316 SSTL	1 5	3.5 3.5	120 120	0.1 0.01
6Mo SSTL	5	3.5	150	1.0
22Cr Duplex SSTL	3	3.5	150	0.02
25Cr Duplex SSTL	5	3.5	150	0.1
Titanium		3.5		>> 5

Table 3: H_2S limits for CRA

(Source-NORSOK standard M-001)

6.5 CORROSIVITY EVALUATION AND CORROSION PROTECTION

According to NORSOK M-001, Corrosivity assessment as a base must incorporate the following, They are

- O_2, CO_2 & H_2S contents
- Operating pressure, temperature, flow rate,velocity & pH
- Halides and metal concentration
- Organic acids
- Sand production
- Biological actions
- Condensing conditions

6.6 CATHODIC PROTECTION

Cathodic protection is a method used to protect the metal surface due to corrosion by creating that exterior surface the cathode of an electrochemical cell. The cathodic protection systems are generally designed on the basis of environmental conditions and neighbouring structures. History of CP begun in the 1820’s when sir Humphrey Davy enquired the corrosion of copper sheet cladding on the hulls of warships on behalf of the Royal Navy by adhering small amounts of metal or zinc to the metal surface. The principle of Cathodic Protection is in connecting an external anode to the steel to be defended and passing of an electrical dc current so that all areas of the steel surface becomes cathodic with consider to the anode and thus do not corrode. By selecting a material more anodic than the other alloys, these alloys become protected cathodically.

Pros & Cons of Cathodic Protection:

- Cathodic Protection is the only method which will reduce corrosion rate near to zero.
- Corrosion rate reduction can be attained even if total protection is not possible or practicable i.e. < -800mV
- Chances of damaging the protective coatings (cathodic disbondment) are likely when improperly applied.
- Cracking as a result of hydrogen embrittlement
- Interference of Stray current (Normally onshore)

6.7 PROTECTIVE COATINGS

Protective coatings are applied for dividing the surfaces that are susceptible to corrosion from the components in environment which cause corrosion to happen. although, that protective coatings cannot provide 100 percent protection. Protective coatings are generally applied for carbon steel pipelines in order to mitigate the corrosion. Coatings can be applied on both internal and external.The internal coatings should be compatible with the fluids flow inside the pipelines and the external coatings with respect to the environmental conditions.If localized corrosion at a outer layer defect is expected to origin failure, Extra corrosion control measures should be applied. Poor surface preparation causes majority of coating failures. Coatings are especially useful when used in combination with other methods of corrosion command such as cathodic defence or galvanic corrosion .

6.8 CORROSION MONITORING

Corrosion monitoring should atleast be carried out to carbon steel flowlines. There are various corrosion monitoring techniques available.

Weight loss Coupon

Weight reduction coupons are basic, efficient and sensitive tool for estimating the corrosion rates quantitatively. This technique uses small samples of metal exposed to an affected environment for a period of time to find out the response of the metal. The coupon is capable of determining other problems like erosion scaling, and fouling due to its physical shape and location.

A single coupon can't be used to figure out if the metal loss rate was uniform or changing during the introduction period. Introducing more coupons at same time and removing and assessing those individual coupons at particular coupons can get info about the erosion rate. The coupons are made from the same material of the used pipe or made from a material which is similar metallurgically to the pipe. Coupons are mounted with coupon holders. The holders are marked so the orientation of the coupon with respect to flow can be adjusted. Corrosion rate can be calculated using the formula given below:

CR = (W x 3.65 x 105) / (A x T x D)

Where:

CR = average corrosion rate, mm/y

W = mass loss, grams

A = initial exposed surface area of coupon, mm2

T = exposure time, days

D = density of coupon metal, gram/cm3

Electrical resistence

Electric resistance (ER) probes are alike as weight loss coupon aside from it measures the change of electrical resistance whereas the weight loss coupons screen the metal wastage. The pros of electrical resistance method against the weight loss coupon technique is that by taking progressive metal loss readings, the corrosion rate can be calculated with respect to time in real time instead of waiting months for coupon data.

This technique requires sensors with metal element and a monitoring device. ER sensors monitors material loss directly, hence it does not need continuous conductive path. This method can be used to monitor corrosion in regions where water wetting is not persistent or under deposits where conductive may be restricted.It is used to monitor any material loss which is caused by erosion or cavitation etc., in non-corrosive fluid. The figure given below shows ER probes metal loss output over time. The conversion to corrosion rate is the slope of the line.

Linear polarization resistence

This technique is used for monitoring of uniform corrosion and qualitative pitting propensity. The method involves polarizing the concerned metal and measuring the resulting current. It needs a probe which have 2 or 3 electrodes and a monitoring device. The benefit of using this method against WLC and electrical resistence probe is that it provides a fast measure of fluid corrosivity. It is more sensitive towards environmental change.

This technique has limits of operation, which depend on corrosion rate, and electrical conductivity of the process media Thus this method requires a relentless conductive path and is generally used only where conductive fluids (water) is present.

Zero Resistance Ammetry

Zero Resistance Ammetry is not the most routinely corrosion monitoring procedure as it needs a good understanding of the electrochemistry method when corrosion happens. ZRA is commonly used to measure galvanic effects in a system. ZRA is nothing but a current to voltage converter. It gives a voltage output relative to the current streaming between its two input terminals while forcing a Zero voltage drop to the external circuit.

If both the electrodes were similar then very little coupling current would flow. In genuine life the two electrodes will be somewhat different, one being more anodic or cathodic than the other and a little coupling current will exist. On that point envisage the electrode chopped in half and the two parts attached via a ZRA. The ZRA will capture some of the current flowing between the (now differentiated) anodic and cathodic regions.

Electrochemical Noise

Electrochemical noise is a simple technique on micro perspective viewpoint. ECN is measurement of potential and electrode between two electrodes. It can be identical material or one material vs reference electrode. This method will create huge amount of data at high rate generally for every second, which needs computer system to process those obtained data.

ECN measurements of a passive metal will give corrosion currents and potentials without any fluctuations. Although, once the situation change and a corrosion pit begins to form, then usual patterns in the corrosion potential and currents can be noted. Further pit propagation will have another pattern and the similar one goes for passivation. A exclusive signature for each kind of event should be known to evaluate ECN data.

High sensitive electro ratio metric Techniques

Two distinct techniques are incorporated in this methods. Bith have similar technical capability which is electro radio metric. Two techniques are Ceion and Microcor.

Field signature method

This technique detects cracking, pitting, metal loss and grooving due to corrosion. It detects the changes in the fluid flow through metallic structure. An benefit of the FSM system is, if the probability of severe conditions increases significantly if corrosion is identified during inspection, then it can be installed without a system shut down. FSM can also be used in subsea, but that is more sophisticated, so proper planning is necessary to make it sucessful.

Water analysis

Water analysis is generally underrated as corrosion monitoring tool. Water analysis along with some corrosion monitoring techniques provide good data and hence will act as a strong corrosion control resource. To get fruitful results some parameters are needed, they are

- Iron
- Manganese
- Bicarbonate
- pH
- Sulfide
- Organic acids

Corrosion monitoring selection systems

Table below provides information about the technique which can be used with respect to the production fluid.

Technique / Service	Water (5% oil)	oil (<5% water)	Wet gas	Three phase	erosion
Electrical resistence	X	X	X	X	X
Weight loss Coupon	X	X	X	X	X
Linear Polarisation resistence	X				

Zero Resistence Ammetry	X				
Electro chemical Noise	X	X	X	X	
Field signature method	X	X	X	X	X
High Sensitivity	X	X	X	X	X
Water Analysis	X	X	X	X	

Table 4: Corrosion monitoring Vs operational service

(Source- Alabam, Cornetl, Feltoas, Fullejt, Hollied, Jessef, Leim20, Nikamvv, Sadair, Onewiki)

6.9 CHEMICAL TREATMENT

Chemical treatment is one of the effective mitigation measures currently practicing by most of the offshore industries. Chemical treatments are considered to be an integral part in pipeline integrity program. To prevent degradation and various contaminants, offshore industries need different chemical treatments. Selection of injection method plays an important role which needs to be cost effective as well as it should provide reliable solution.

Some common types of problems like chemical corrosion, bacterial corrosion, mineral deposits, hydrate formation, water vapor problem, and paraffin problem are found in oil and gas production operations. These problems can be treated by chemical injections.

Carbon dioxide, hydrogen sulphide and oxygen are the main components associated with corrosion of produced fluids. The selection criteria of using corrosion inhibitors are generally based on type of corrodent, type of production and relevant experience. Corrosion inhibitors will mostly work by adsorption process on the exposed metal surface.

Oxygen normally will not found in unaltered produced fluids. It usually begins to introduce when the produced fluids are treated. Corrosion by oxygen is controlled by chemical reaction instead of adsorption process. The most common form of scavengers (oxygen inhibitors) is sulphites with ammonium bisulphite. Sulphates and their reaction products are water soluble and so it will be discharged with the produced water. Scavengers are generally used at less than 100ppm concentrations. Injection water is also treated using oxygen scavengers.

The most common corrodent is carbon dioxide, where as hydrogen sulphide set to provide substantial risk to human, health and environment. Oil soluble corrosion inhibitors are more effective as they provide stable and durable film. In case of requirement of more water solubility, dispersants or surfactants or quaternary amines can be added.

Chemicals injecting on various platforms

The production rate of oil, water and gas are the basis factor for deciding the amount of most of the chemicals that are to be injected.

Scale inhibitor

Scale inhibitors are added to prevent the formation of scale deposits in pipes and equipment. Scale formation mainly depends upon the temperature, pressure and water cut. On the basis of water content the amount of scale inhibitor to be injected will be decided. Inappropriate scale inhibitor or lack of scale inhibitors will generate back pressure in wells.

Anti-foaming agents

Foam absorber added to the production flow to prevent the formation of foam in the separator that provides better gas / liquid separation. The quantity of anti- foaming agents to be injected is based upon the total oil production rate and also depends upon the type of the anti- foaming agent.

Emulsion Breaker

Emulsion breakers are added to prevent the formation of oil / water emulsions in the separator which improve oil / water separation. Emulsion breakers injection rate are based upon the oil and water production rate.

Corrosion inhibitor

Corrosion inhibitor will be injected in export pipeline for oil. The quantity to be injected will be based on GOR, GLR and Water cut. Inhibitors density is similar or slightly heavier than water. It needs to be injected in continuous or batch injection distributed via a nipple with check valve.

Corrosion inhibitors are complex compounds which can be sorted into four groups, they are

- Amine imidazolines
- Amines and amine salts
- Quaternary ammonium salts
- Nitrogen heterocyclic’s

H_2S, O_2, and CO_2 scavengers

To reduce H_2S, O_2, and CO_2 content, these scavengers are added. Density is to water and must be dispersed and distributed thoroughly within the process media for maximum contact time. It requires continuous direct injection distributed via an atomizer.

Paraffin inhibitors

Paraffin inhibitors are injected in crude oil. Paraffin inhibitors change the wax crystal structure and it reduces the wax build up in the oil systems. Their densities are slightly lighter than water and must be dispersed and distributed thoroughly within the process media for maximum contact time. It also requires continuous or batch injection distributed via injection quill with check valve.

Hypochlorite

Hypochlorite is used in water, seawater and firewater system which acts as a disinfectant and prevents biological growth in pipes and equipment.

Biocide

Biocide is added into the oil phase separator to reduce the possibility of formation of biological growth in the system.

Gas fields

Glycol / Methanol

Glycol / methanol are pressure equalization fluid. The used glycols can be recycled to equalize the pressure across various valves. Methanol mixture is added if there is a risk of hydrate formation in the gas treatment system. Characteristics of glycol are Density slightly heavier than water. It will be applied to the interior wall of the pipeline or vessel. It requires continuous or batch injection distributed via a quill with check valve. Methanol density is slightly less than water and must be dispersed and distributed thoroughly within the process media for maximum contact time. It requires continuous direct injection distributed via an atomizer. In case of distributing in liquid medium the Injection quills should be used.

Chemical Injection system

Chemical injection systems will store, transport and inject chemicals into various process systems. The main purpose of the chemical injection system is to prevent corrosion, biological growth, hydrate formation, Scales deposition etc. Chemicals are also injected to enhance the separation processes and to reduce the friction in export pipelines. Injection systems consist of various subsystems which includes batch and continuous injection of chemicals to process and utility systems. The storage tanks, injection pumps and their related instrumentation devices are the main components in a chemical injection system.

The required injection rate can be calculated on the basis of concentration of water, oxygen etc. The ratio calculation is the main component where it calculates the required chemical flow rate on the basis of production rate compared to the dosage set point. The graph shown below provides overview of production rates of Gas oil ratio (GOR), Gas Liquid ratio (GLR) and water cut (WC) from the choke valve. These rates are considered to be the basis for calculating the dosage rates.

Graph 1: Shows an overview of production rate of GOR, GLR and WC.

(Source-Aker solutions Corrosion Monitoring data, 2012)

7. ALTERNATIVES TO CURRENT PRACTICES

The mitigation measure for corrosion is just not a part of corrosion control strategy for the production wells. For new development wells in the future the corrosion control can be accomplished mostly through material selection only, thus low alloy tubing is not anticipated to have adequate service lifetime without corrosion inhibitor, suitable corrosion resistant alloy can be selected. In this paper the following corrosion resistant alloy is considered for comparing with current practices of carbon steel they are,

- Stainless steel
  - 316 Stainless Steel
  - 6MO Stainless Steel
  - 22% Cr Duplex Stainless Steel
  - 25% Cr Duplex Stainless Steel
- Titanium

7.1 STAINLESS STEEL

No metal, aside from gold and platinum in their characteristic state, are totally corrosion free. But stainless iron alloy has proven in thousands of applications, that it is one of the most economical solution's to battle the ever present components that origin corrosion. Yes as the name suggests - it is stain-less, stain-proof.

Stainless steels are generally iron base alloys which contain approximately 11% cr. The presence of chromium helps to prevent the rust formation from the atmosphere. Stainless steel alloys material cost is almost 10 times the cost of Carbon steel. Stainless steel is widely used material in offshore facilities because of their corrosion resistance at ordinary temperature and conditions. But, in hazardous atmosphere and at high temperature the surface of the alloy is attacked severely which results in the formation of Cr_2O_3, NiO or Fe_2O_3 scales. There are five types of stainless steels,

- Austenitic stainless steel (304, 304L, 316, 316L etc...)
- Martensitic stainless steel
- Ferritic stainless steel
- Duplex stainless steel (22 Cr, 25 Cr)
- Precipitation hardening

The table shown below provides good overview of their strength relative to corrosion.

* Superior properties

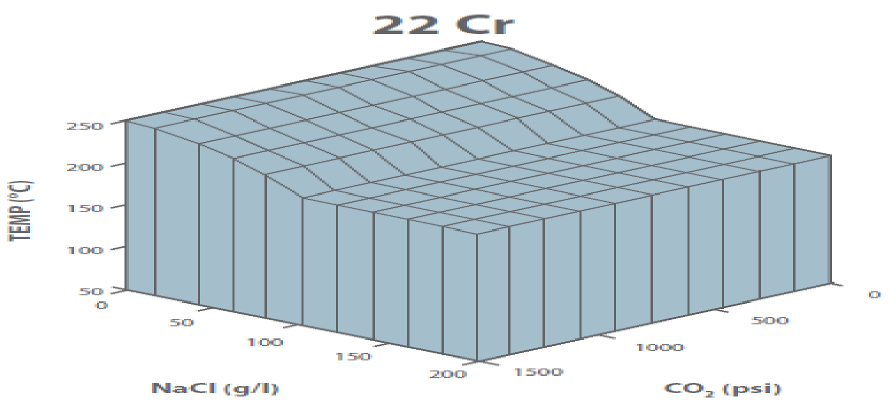
- Lower properties

Property	Austenitic	Ferritic	Duplex	Martensitic	Precipitation Hardening
Strength	–	*	**	***	***
Wear Resistance	–	–	*	**	**
Formability	***	**	**	–	*
Weldability	**	–	**	– –	–
Resistance to General Corrosion	**	*	**	–	*
Resistance to Pitting Corrosion	**	*	**	–	*
Resistance to Stress Corrosion, chlorine induced	–	**	**	–	–

Table 5: Showing Properties of stainless steel relative to corrosion

(Source-Corrosion prevention 316 presentation)

Stainless steel generally will not corrode as uniform as like corrosion in carbon steel alloys. However at some concentrations like hydrochloric acid and sulphuric acid will attack the passive layer uniformly. More common forms of corrosion in stainless steel are pitting corrosion, Crevice corrosion, Inter granular corrosion, Galvanic corrosion and Stress cracking corrosion. Stress corrosion cracking can be susceptible in case of using austenitic stainless steels, along with conditions like critical environment and some form of tensile stress presence. But duplex stainless steels have improved resistance to stress corrosion cracking.



Graph 2: Corrosion resistance of 22 Cr Duplex sstl in CO_2/Nacl environments in the absence of oxygen and H_2S

(Source-** Corrosion Resistant alloys (CRAs) in the oil and gas industry**, 2011)

The PREN, CPT, CCT for the corrosion resitant alloys are mentioned in the table below.

Materials	PREN	CPT (º C)	CCT (º C)
316	24-26	5-15	<5
6MO	46	65-80	30-60
22 Cr Duplex	35	20-42	17.5-25
25 Cr Duplex	42	55-88	35-43

Table 6: Typical PREN, CPT, and CCT Numbers for Stainless Steels

(Source- R.T. Hill, F.A. Ramirez, A.L. Perez, and B.A. Monty, 2012)

Note:

PREN - Pitting Resistance Equivalent Number

CPT - Critical Pitting Corrosion Temperature

CCT - Critical Crevice Corrosion Temperature

7.1.1 316 Stainless Steel

Grade	UNS	C	Si	Mn	P	S	Cr	Ni	Mo	N
316 SSTL	TP316	0.08	0.75	2	0.045	0.03	18	14	3	0.10

Table 7: Composition of 316 stainless steel

7.1.2 6Mo Stainless Steel

Grade	UNS	C	Si	Mn	P	S	Cr	Ni	Mo	Cu	N
6Mo	S31254	<0.02	0.70	1	0.30	0.010	20	18	6.1	0.75	0.20

Table 8: Composition of 6Mo stainless steel

7.1.3 Duplex

Grade	UNS	C	Cr	Ni	Mo	W	Cu	N
Duplex	S31803	0.02	22	5.5	3.0			0.17
	S32205		22.5	5.8	3.2			0.17

Table 9: Composition of Duplex stainless steel

7.1.4 Super Duplex

Grade	UNS	C	Cr	Ni	Mo	W	Cu	N
Super Duplex	S32750	0.02	25	7	4.0		0.5	0.27
	S32760	0.03	25	7	3.5	0.6	0.5	0.25

Table 10: Composition of Super Duplex stainless steel

7.2 TITANIUM

Titanium metal is highly reactive and has excellent corrosion resistance properties. It has low density and high strength to weight ration of any metal. It's an expensive material. Titanium can be available in various grades with different alloy compositions. The most commonly used grade with corrosion resistant properties are grade 7 containing 0.15% of palladium and grade 12 containing 0.3% Molybdenum and 0.8% nickel.

The oxide film formation provides the material an outstanding corrosion resistance in aggressive environments. When titanium is exposed to the atmosphere which contains oxygen, it forms a thin consistent film of oxide typically TiO_2, may also consists of mixtures of Ti_2O_3, and TiO. It needs sufficient oxygen to be present in order to form the healing layer which can reform even if mechanically damaged. If there is no sufficient oxygen then it is difficult to regenerate the layer. The oxide film formations even perform well in chlorine and organic chlorides containing environments. But it doesn't provide good resistant to chlorine when the temperature is more than 110^0C.

There are various methods available to even increase the resistance in the reducing environments. They are,

- Anodizing and thermal oxidation, the surface oxide film thickness can be increased.
- Surface coating can be applied
- In order to allow oxide film stabilization, oxidizing inhibitors can be added to reducing environments.

8. CHARECTERISTICS FOR COMPARING ALTERNATIVES

8.1 SAFETY AND ENVIRONMENTAL ASPECTS:

Safety and environmental aspects is one of the important factor to be analysed when selecting material for flow lines. In previous years, the Norwegian Petroleum Directorate (NPD) has conveyed worries regarding some situation related to material selection and safety, triggered by previous experiences in the North Sea. Numerous gas leakages have been reported in Norwegian continental shelf in previous years. Some of the leakages are due to different type of failures on subsea pipeline wall fractures. Outcome of these failures are significant. The effect on environment and human health and safety has not been significant in these cases. Most of those occurrences are smaller topside gas leakages. Luckily none have set on fire. Therefore it is necessary to consider in terms of safety as an important factor while selecting material quality.

8.2 LIFE CYCLE COSTING

Life cycle costing is one of the best tools used to select the material with respect to cost. Increasingly, material selection is made not blindly selecting the lowest initial installed cost, but should also on future perspective view of the costs incurred during the project duration. This Life Cycle Costing (LCC) analysis utilizes established diverse activities to compare the costs such as selection of various equipment's, alternative materials selections for different systems, optimization of various production process by calculating the present value of future costs associated with the selected materials. LCC study will throw light on major cost drivers and based on this data the choice of design alternatives can be made.

According to NORSOK standard O-CR-002, Life cycle cost is the summation of cost estimate that determines the life cycle cost of a product over a period of time. The main objective is to select the most cost effective approach from the alternatives.

In general, Life Cycle Cost = Capital Cost + Operating cost + Cost of deferred production

Where Capital cost is calculated by adding the following cost elements

Capital cost

- Equipment cost
- Installation cost
- Non recurring investment cost
- Design and administration cost
- Spare units or assembles cost

- Commissioning cost
- Insurance Cost

Operating cost shall be calculated by adding the following cost elements

- Man-hour cost
- Inspection cost
- Spare parts for operation
- Energy consumption cost
- Chemicals/Inhibitors Cost

All these costs shall be discounted back to the base year

$$\sum_{n=1}^{N} \frac{OC}{(1+i)^n}$$

Where,

OC = operation & maintenance cost

n = year

i = discount rate

Cost of deferred production can be calculated by adding following cost elements

The general formula for cost of deferred production (CDP) is as follows:

CDP = E p D L CDP

Where:

CDP = Cost of Deferred Production.

E = Average number of critical failures per year.

p = Probability of production reduction.

D = Duration of production reduction.

L = Quantity of production loss per time unit.

CDP = Cost of one hour downtime per year throughout the lifetime calculated as the difference in Net Present Value between a production profiles with the simulated availability and with one hour lower availability per year.

There are also various methods available for performing the life cycle costing in order to choose best from different alternatives. They are

1. **Internal rate of return (IRR)**
2. **Net present value (NPV) or present worth method (PW)**
3. **Discounted payback (DPB)**
4. **Benefit-cost Ratio (BCR)**
5. **Present worth of future revenue requirements (PWRR)**

Internal Rate of Return (IRR):

The IRR is tougher to assess than the NPV. The IRR is defined as the discount rate at which the Net present value becomes zero. The IRR comprises of the interest cost or borrowed capital in supplement to existing profit or loss. A project is advised financially more favorable when the discount rate at which the NPV gives positive value. Once all the cash flows have been accounted for over the life of a project then IRR can computed by an iterative procedure.

Present Worth of Future Revenue Requirements (PWRR):

The PWRR is mainly applicable to regulated public utilities, for which the rate of return is more or less fixed by guidelines. The major disadvantage in this PWRR method is that it is inadequate where alternatives are vying for restricted amount of capital as it does not identify the alternative that produces the utmost return on invested capital.

Discounted Payback (DPB):

All these methods are mainly based on present worth concept. But each has its own pros & cons. The payback period is a somewhat easy and simple concept. It is defined as the amount of time required to retrieve its initial project expense. Discounted payback takes the time value of money into concern by modifying all future cash flows to time zero, before calculating the payback period. It is a very basic method that can be utilized to screen candidate projects.

Benefit-cost Ratio (BCR):

The benefit-cost ratio method (BCR) is more related to the IRR method in the fact that both methods engage assessment options not only for economic measures compared with a "do-nothing" scenario, but also for incremental measures affiliated with incremental capital investments.

Present worth (PW):

The Present worth also referred as Net Present Value (NPV) is considered as the most easiest and direct form of the five methods. It consequently has the broadest application to new technology decision and engineering economy problems. Many industries mention this method as the discounted cash flow method of analysis.

This generalized equation is developed by Vernik.

The equation below (NACE 3C194,1994) is generally used in LCC calculations:

$$(PW) = -P + \{\frac{t(P-S)}{n}\}(P/A,.i\%,n) - (1-t)(X)(P/A.,i\%,n) + S(P/F,i\%,n)$$

Where,

PW	=	present worth
P	=	Initial investment or Capital cost
T	=	tax rate

S represents salvage value

A is the equivalent annual cost

i is the effective interest rate [discount rate]

n is the number of compounding periods [years]

X is the operating expense

F is the future worth of the asset

The term P represents the project expense during start up at time zero. Therefore it is represented in negative value. It is not necessary to convert this value to a future value in time, as the PW approach discounts all money values to the present. Second Term [{t (P-S)/n}(P/A. I %, n)] in this equation represents the depreciation of a system.

Third Term [-(1-t) (X) (P/A, I %, n)] in this generalized equation consists of two terms. One is (X) (P/A, I %, n) that represents the cost of items properly chargeable as expenses such as the maintenance cost, inspection cost, and inhibitors cost. As this term involves expenditure of money. It comes with a negative sign. The second part t(X) (P/A, I%, n) accounts for the tax credit associated with this expense and because it represents a saving it is associated with a positive sign.

Fourth Term [S (P/, I %, n)] translates the future value of salvage to present value. This is a one-time event rather than a uniform series and therefore it involves the single payment present worth factors. Many corrosion measures such as coatings and other repetitive maintenance measures have no salvage value in which cases this term is zero. Present Worth (PW) can be converted to equivalent annual cost A by using the following formula:

A = (PW) (A/P. I %. n)

It is possible to calculate different options by referring to interest tables or by simply using the formula describing the various functions.

The capital recovery function (*P/A*,. is

$$\left(\frac{P}{A}, \text{i}\%, n\right) \qquad \text{where} \qquad P_n = A\,\frac{(1+i)^n - 1}{i\,(1+i)^n}$$

The capital recovery factor (*A/P*). or how to find *A* once given *P*. is

$$\left(\frac{A}{P, i\%, n}\right) \qquad \text{where} \qquad A_n = P\,\frac{i\,(1+i)^n}{(1+i)^n - 1}$$

The LCC analysis is for different material options for the flowlines is done in chapter 9.2.

8.3 RELIABILITY

Corrosion in a flow line or in general a pipeline significantly affects the strength and thereby raises the question of integrity. The corrosion over a period of time, if unattended, circularize and disperse with respect to size and quantity. Such an effect on flow line is directly proportional to the time the flow line is exposed to conditions that enhance corrosion. The highly unavoidable practicality that corrosion in offshore and especially in Norwegian Continental shelf, is random, radically distinctive and without equal propagation and rarified offers no direct solutions but serious challenges to encounter the compounding effects. Hence NORSOK standard M-001 puts forth the reliability characteristic to be evaluated while selecting the material for the flow line. The results of such an effect can be quantified using the reliability characteristic of the flow line. Reliability can be defined as *"The probability that an item can perform a required function under given conditions for a given time interval"*(IEV 191-12-01, 2008). This means that reliability is measure of the likelihood that the flow line will perform the intended functions or probability that a benchmarked quality level is maintained in the system during the operational life cycle of the flow line.

The effects of corrosion are in one way or another dependent on the operating and environmental conditions surrounding the system and cannot be quantified using the deterministic models suggested by the scholastic literatures or industrial standards. The objective of the deterministic models can be envisaged to counter the corrosion effects by limiting the unavoidable repairs/damages and calling for replacements. However, the deterministic models do not provide an opportunity for optimization of corrosion control measures and at the same time not form a complete solution for maintenance and replacements. In order to qualify the solutions without significant qualification, the probabilistic models are deemed to be pejorative that offer solutions to quantifying reliability especially for a gross finish to corrosion control (Bea, 2000). The models are expressed using the statistical distribution functions with practical parameters such as variables of strength and load as opposed to coefficient of safety used by the deterministic models.

Taken by the understanding that corrosion is inevitable or the effects of corrosion cannot be ceased but in turn can be reduced, the probabilistic and deterministic models are used to represent the reliability characteristic of flow line materials. In order to perform reliability analysis or quantify reliability, the touchstones that can establish the failure of a pipeline is to be determined. The touchstones adapted for defining the limit state function are strength or the ability of the flow line material to resist failure and the load or force that can produce failure of a flow line. According to Vrijling (2000), the limit state function is represented as

$$Z = R - S$$

where,

Z = Limit State Function

R = Strength

S = Load

The values of limit state are evaluated as when it tends to be less than 0, then the system is in failure mode and when it is more than 0, then the system is in operation mode. Using the limit state function, the probability that the system is in failure mode can be represented as follows.

$$Pf = \Pr (Z \leq 0) = \Pr (R \geq S)$$

Where,

Pf =Probability of failure

$\Pr (Z \leq 0)$ = Probability that the system is in failure mode depending on the limit state function

$\Pr (R \geq S)$ = Probability that the system is in operational mode depending on the limit state function

The reliability of the system is therefore the probability of the system is not in failure mode and can be represented as

$$P_r\,(Z > 0) = 1 - P_f$$

8.4 AVAILABILITY

According to M-001, one of the key factors to be evaluated while selecting the material for flow lines is the availability of the same the market. However, due to rapid developments in the offshore oil & gas (O&G) industry sector, especially in NCS, the management of asset availability and asset management offers a series of challenges. Out of the many challenges spare parts management, complexities in inventory management, economics of inventory, availability of asset management personnel, mismatch between actual demand, purchasing period, stock piling of unnecessary inventory parts etc. are some of the critical factors that can escalate risk and at the same time management cost. Traditionally it is believed that the while managing an asset, the more the inventory the less would be the operating cost and down time. But the belief is no longer under application due to the changing dynamics of offshore asset maintenance and management.

Current trends and developments in technology has enhanced the design and operating life of the asset. Additionally, the experiences gained and nourished over the last two decades has significantly provided means to have an assets execute their respective functionalities for longer life. However, that does not take away the need for incorporating maintenance needs and protocols into the system. Such a protocol is driven by laboratory experiments and application of suitable remedial measure to ensure that the asset manages to complete the years of operation it has been designed for.

Maintenance management philosophies over the last two decades, such as run-to-failure, ensured that the offshore asset spend economically on maintenance needs and avoid any preventive break downs. Such a philosophy has led to larger costs due to system downtime, high labour cost, low production, high inventory costs etc (Mobley, 1990). To satisfy some of the core principles and objectives of asset management which are in-line with current dynamics of offshore operations, the Availability with respect to market has therefore been evaluated with Asset Availability perspective. Such an evaluation encapsulates the core principles and objectives of asset management such as reduce the need for inventory management and associated inventory costs, undermine the significance of demand and supply, ensure that the assets down time is as low as practically reasonable, optimize the value of the asset, reduce inspection requirements, the eventual risk of asset failure due to unexpected critical events and reduce operational risk. In addition, the Norwegian petroleum directorate encourages and expects the operators to adhere to HSE guidelines and regulations such that there is zero tolerance for accidents , unexpected chain or events or scenarios that can directly or indirectly have significant effect on the availability of the asset. In other words, the more the availability of an asset, the more is the technical integrity of the asset.

According to British Standards (BS EN 13306:2010), the Availability of an asset is its ability to remain in a state of operation, perform its functional objective for the period and operating conditions the asset has been designed for under the assumption that the asset receives all the required resources in the form of maintenance needs. Rausand and Høyland (2004), define Availability as *"The ability of an item (under combined aspects of its reliability, maintainability and maintenance support) to perform its required function at a stated instant of time or over a stated period of time".* The aforementioned definitions provide an assertive direction towards having the system in a state of operation (functional) with some scheduled maintenance operations. In other words, the availability can be quantified using the formula,

$$A = \frac{MTBF}{MTBF + MTTR}$$

Where

A = Average Availability

MTBF = Mean Time Between Failures

MTTR = Mean Time To Repair

With the objective of this research basing on the evaluation of material based on the corrosivity property on the hydrocarbon systems, the availability factor of material selection is drawn from the corrosion inhibitor availability perspective. According to M-001, corrosivity which is a principal component of the degradation mechanism in offshore flowline materials, the property of corrosivity has to be evaluated based on the availability of the inhibitor. The availability of inhibitor defines and determines the time the inhibitor is present during system's operation or functioning at the concentration levels that is above or below the required minimum dosage. In order to quantify the Availability characteristics of material, the percentage availability formula as discussed in M-001 has been adapted in this research and is formulated as

A % = 100 x (inhibitor available time)/(lifetime)

Corrosion allowance (CA) = (the inhibited corrosion allowance) + (the uninhibited corrosion allowance)

CA = (CRinhib x A %/100 x lifetime) + (CRuninhib x {1 – A %/100} x lifetime) (3)

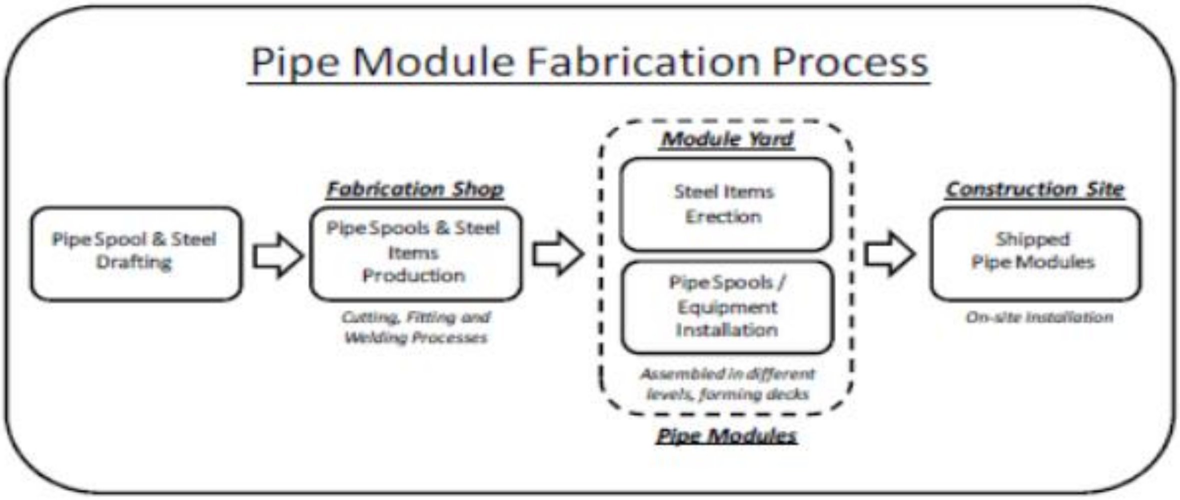
where

CRinhib = inhibited corrosion rate.

CRuninhib = uninhibited corrosion rate (from NORSOK M-506).

8.5 FABRICATION

According to NORSOK standard M-001, one of the perspectives that is required to be attended to while selecting the material for oil and gas flow lines is Fabrication. Generally, the oil and gas flow lines or any piping for offshore is fabricated onshore in the name of fabrication spools depending upon the means of transport and are installed in offshore module. The fabrication of spools is done is an onshore fabrication yard or shop using the recommended industrial standards and techniques. Such standards and techniques govern the type of cutting required on the pipe, procedures of welding and types of fitting being used. The fabrication yard is equipped with the tools and paraphernalia to cater to the needs and demands of the industry and site. Once the spools are fabricated in the shop, they are transported to the site for installing using the erection items. The following figure adapted from (Song, Mohamed and AbouRizk, 2009) describes the work process involved in the fabrication activity.



Flowchart 1: Pipe Module Fabrication Process

(Source- Song.L, Mohamed.Y, and AbouRizk.S, 2009)

9. EVALUATING ALTERNATIVES WITH RESPECT TO CURRENT PRACTICES

9.1 CARBON STEEL VS CORROSION RESISTANT ALLOYS WRT SAFETY AND ENVIRONMENTAL ASPECTS

Concerns about the safety and environmental aspects in oil & gas industries are increasing in public as the environmental nongovernmental organizations keep on forcing the operating companies for more transparency and responsibility towards environment. Chemicals are used in all aspects of oil and gas industries from discovering, well development, drilling, production, transmission and storage.

The main failures of carbon steel X65 pipelines occurs due to corrosion and erosion. Those failures have great impact on safety and environment. The table below provides an overview of internal corrosion mechanism between carbon steel and corrosion resistant alloy. It is necessary to consider the materiasl which are prone to more degradation mechanism and whether the mitigation measure to be used are effective enough to counter the degradation mechanisms in order to avoid failures and their consequences.

Corrosion Mechanism	Carbon Steel	Corrosion Resistant Alloy
CO_2 & H_2S Corrosion (general mass loss)	**Yes**	**No**
H_2S Cracking Corrosion (SCC, HICC)	**Yes**	**Yes (SCC)**
Chloride Induced/Chloride contribution to pitting corrosion	**Yes**	**Yes**
Chloride SCC	**No**	**Yes**
Corrosion from dissolved oxygen	**Yes**	**Yes (Pitting and cracking in the presence of chloride and high temperature)**
Microbiologically induced Corrosion	**Yes**	**Yes**

Table 11: Comparison of internal corrosion mechanism between carbon steel and corrosion resistant alloy.

(Source-R.T. Hill, F.A. Ramirez, A.L. Perez, and B.A. Monty, 2012)

Stress cracking corrosion is one of the threat in stainless steel material which causes brittle failure of metallic surface by due to stress and localized corrosion. It has been reason behind to causefailure of high strength steels. The H_2S and chloride environment is the main cause for failures due to SCC. In this paper when pipelines are considered, If carbon steel is used, chemical treatment is the effective mitigation measure practiced by current oil & gas industries. Indefinite chemicals are used with the combination of various chemicals manufacturers resulted in availability of hundreds of different chemical products. Due to this widespread usage of chemicals, it is necessary to access data regarding their efficiency and their likely environmental impacts.

Any chemical that is being introduced in the North-Sea requires to be tested on the following environmental properties:

On organic component level

- Bioaccumulation
- Biodegradation

On Product level

Toxicity on:

- Algae
- Crustacean
- Sediment reworker
- Fish

The environmental problems arise with the discharge. When it comes to production chemicals, the chemicals that are mostly used are organic which are used in continuous process in small quantities. The chemicals used in production process are emulsion breakers, corrosion inhibitors, biocides, scale inhibitors, H2S, O2, and CO2 scavengers, anti-foaming agents and other chemicals for specific applications. There is a general assumption that all those production chemicals are discharged to the environment. However there is also an assumption that the chemicals that ends up in water phase discharged along with the produced water and the chemicals ends up in oil phase will transferred to refinery along with the crude oil for further processing

Irrespective of material quality there will some kind chemicals are injected into the flowlines in order to prevent scale formation and other applications. Chemicals that are used should be handled safely in order to prevent hazardous situations. According to NORSOK S-003, the chemical handling system says that, the chemical storage system design should be intended to minimize risk of spills (e.g. breakage of sacks) and facilitate accumulation of spills. Hazardous chemicals spill that cannot be recycled are stored transported to onshore as hazardous waste.

The transfer system between transport and storage tanks ought to be a closed system that permits complete draining of transport tanks. Solely distinctive couplings ought to be used on transfer systems so as to cut back risk of unintentional transfer to a wrong tank.
A separate drain to a chemical spill tank ought to be provided from the chemical injection package/system. It ought to be doable to modify from the hazardous drain system to the current system throughout filling and maintenance operations. According to Norsok S-002, The following substances and products are prohibited. They are asbestos and asbestos-containing materials, mercury compounds, cadmium compounds, polychlorinated biphenyl and polychlorinated biphenyl-containing materials, halon type chemicals, chlorofluorocarbon type chemicals, tetrachloromethane, 1,1,1-Trichloroethane.

9.2 Carbon steel vs Corrosion resistant alloys wrt LCC

LCC Analysis for material selection for flowlines

The LCC analysis is done to investigate different material options for the flowlines and provide the future recommendation of the best option for the Final Engineering stage. The various options selected for evaluation are

- Bare Carbon steel
- 316 stainless steel
- 6MO stainless steel
- 22 Cr Duplex stainless steel
- 25 Cr Duplex Stainless steel
- Titanium

The production fluids flows through the flowlines consists of high concentrations of CO_2 and H_2S which are highly corrosive to carbon steel material. Therefore corrosion inhibition is required to control the corrosion rate. Bare carbon steel flowlines with corrosion inhibition via chemical injections are assumed to be the base case for flowlines. Pipeline grade is assumed to be API-5L GR X65. Chemical inhibition is assumed to be continuous process. Even though when film forming corrosion Inhibitor type is injected, the internal corrosion cannot be completely eliminated. Therefore regular inspections, repairs and replacements will be required throughout the service life.

Carbon steel with internal coating can also be used but these coating systems are seen as the next increment above bare carbon steel in terms of initial cost and corrosion protection. Disadvantages concerned with these internal coating is the inadequate adhesion on the wall of the pipe with the coating will leads to peeling or flaking of the coated layer, Erosion problem in coated carbon steel also is one of cause for potential failure. Due to these problems it is necessary to have similar corrosion inhibition systems used in bare carbon steel.

The capital expenditure of Carbon steel and corrosion resistant alloys will vary depending upon the various operating project conditions and external factors. Therefore the economic incentive of carbon steel pipeline should be analyzed for each specific project. Cost of Carbon steel material is less, but to take care of material loss due to corrosion we must provide corrosion allowance, coating and inhibitor protection. In general, carbon steel with corrosion inhibitor option is considered for long distance and larger pipelines of moderate design life.

Duplex stainless steel has high yield strength which permits thin wall thickness and retains the pressure existing and load bearing capability, 22% Cr has 450MPa and 25% Cr has 550Mpa in annealed condition. In requirement of high sour service tolerance 25% Cr Super duplex are preferred. This duplex type of stainless steel has high resistance to corrosion and erosion, and tolerate up to temperature of 232^{o}C with sour service.

These Corrosion resistant alloys material costs are expensive but we need not provide coating and inhibitor protection as corrosion allowance is not necessary for this material type. Therefore the operation and inspection costs are minimal, and unscheduled maintenance is negligible. Welding is more difficult for duplex stainless steel. Fabrication cost is less due to thinner walls and lesser weight.

Assumptions:

The following assumptions are made in for each option.

- The flowline material type and the standards assumed are mentioned in the table given below:

Flowline Material	Material standard	Size(inch)	Diameter (mm)	Pressure Class	Wall Thickness (mm)	SCH
Carbon steel	A333 Gr 6 API 5L X52	10	273.1	1500	28.58	160
316 SSTL	A312 TP 316	10	273.1	1500	28.58	160
6MO SSTL	A312 S31254	10	273.1	1500	21.44	120
22 CR Duplex SSTL	A790 S32750/760	10	273.1	1500	21.44	120
25 CR Duplex SSTL	A790 S31803	10	273.1	1500	18.26	100
Titanium	B861 Gr 2	10	273.1	1500	18.26	100

Table 12: Assumptions of Flowline Material

- Length of flowline will vary considerably; assumption of 100 m length is taken for this LCC calculation.
- The expected life time is assumed to be 25 years.
- 50% loss in wall thickness is considered as the end of life of a flowline. The time required to corrode 50% of the wall thickness at the above corrosion rates are 10 15 and 20 years.
- Efficiency of inhibitor is assumed to be 80% for carbon steel, therefore the corrosion rate will be only 0.4 mm/y which consume 10mm of carbon steel over 25 years of project life.
- LCC for 20 years and 25 years is also calculated for comparative purposes.
- Tax on Capital expenditure is assumed to be 48% for this calculation.
- The Uncertainty factor (inflation) assumed to be 2% for Components and the discount rate is 10 % assumed for Present worth calculation.
- Cost of deferred production is not considered in this analysis.

Oil and Gas Flowlines a full description of the cost factors (capital and operating) involved in LCC analysis of offshore pipelines is given below:

Follwing cost elements are assumed for this analysis:

9.2.1 Cost elements - Bare Carbon steel material with corrosion inhibitor (Option 1)

Capital cost Elements	Nok per meter/ weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	5200	520 000	Inhibitor cost	800 000
Flanges & Fittings		180 000	Inspection	110 000
Fabrication	10000	700 000	Man hour	1 000 000
Installation	500	50 000	Energy	75 000
Commisioning	500	50 000	Spares	47 000
Design & Admin	500	50 000		
Capital cost		**1 550 000**	**Operating cost**	**2 032 000**

Table 13: Life cycle Cost elements for carbon steel

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for Carbon steel (MNOK)								
Year	**Corrosion Inhibitor**	**Inspection**	**Man hour**	**Energy**	**Spare parts**	**Total**	**Present worth**	**PW Cummula-tive**
1	0.800	0.110	1.000	0.075	0.047	2.032	2.032	2.03
2	0.816	0.112	1.020	0.077	0.048	2.073	1.713	3.74
3	0.832	0.114	1.040	0.078	0.049	2.114	1.588	5.33
4	0.849	0.117	1.061	0.080	0.050	2.156	1.473	6.81
5	0.866	0.119	1.082	0.081	0.051	2.200	1.366	8.17
6	0.883	0.121	1.104	0.083	0.052	2.243	1.266	9.44
7	0.901	0.124	1.126	0.084	0.053	2.288	1.174	10.61
8	0.919	0.126	1.149	0.086	0.054	2.334	1.089	11.70
9	0.937	0.129	1.172	0.088	0.055	2.381	1.010	12.71
10	0.956	0.131	1.195	0.090	0.056	2.428	0.936	13.65
11	0.975	0.134	1.219	0.091	0.057	2.477	0.868	14.52
12	0.995	0.137	1.243	0.093	0.058	2.527	0.805	15.32
13	1.015	0.140	1.268	0.095	0.060	2.577	0.746	16.07

14	1.035	0.142	1.294	0.097	0.061	2.629	0.692	16.76
15	1.056	0.145	1.319	0.099	0.062	2.681	0.642	17.40
16	1.077	0.148	1.346	0.101	0.063	2.735	0.595	18.00
17	1.098	0.151	1.373	0.103	0.065	2.790	0.552	18.55
18	1.120	0.154	1.400	0.105	0.066	2.845	0.512	19.06
19	1.143	0.157	1.428	0.107	0.067	2.902	0.475	19.53
20	1.165	0.160	1.457	0.109	0.068	2.960	0.440	19.97
21	1.189	0.163	1.486	0.111	0.070	3.019	0.408	20.38
22	1.213	0.167	1.516	0.114	0.071	3.080	0.378	20.76
23	1.237	0.170	1.546	0.116	0.073	3.141	0.351	21.11
24	1.262	0.173	1.577	0.118	0.074	3.204	0.325	21.44
25	1.287	0.177	1.608	0.121	0.076	3.268	0.302	21.74

Table 14: Operation & Maintenance cost of Carbon steel for 25 years

9.2.2 COST ELEMENTS – 316 STAINLESS STEEL MATERIAL (OPTION 2)

Capital cost Elements	Nok per meter/ weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	26000	2 600 000	Inhibitor cost	0
Flanges & Fittings		725 000	Inspection	75 000
Fabrication	13000	910 000	Man hour	1 000 000
Installation	500	50 000	Energy	50 000
Commisioning	500	50 000	Spares	124 000
Design & Admin	500	50 000		
Capital cost		4 385 000	Operating cost	1 249 000

Table 15: Life cycle Cost elements for 316 Stainless Steel

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for 316 stainless steel (MNOK)								
Year	Corrosion Inhibitor	Inspection	Man hour	Energy	Spare parts	Total	Present worth	PW Cummula-tive
1	0.000	0.075	1.000	0.050	0.124	1.249	1.249	1.25
2	0.000	0.077	1.020	0.051	0.126	1.274	1.053	2.30
3	0.000	0.078	1.040	0.052	0.129	1.299	0.976	3.28

4	0.000	0.080	1.061	0.053	0.132	1.325	0.905	4.18
5	0.000	0.081	1.082	0.054	0.134	1.352	0.839	5.02
6	0.000	0.083	1.104	0.055	0.137	1.379	0.778	5.80
7	0.000	0.084	1.126	0.056	0.140	1.407	0.722	6.52
8	0.000	0.086	1.149	0.057	0.142	1.435	0.669	7.19
9	0.000	0.088	1.172	0.059	0.145	1.463	0.621	7.81
10	0.000	0.090	1.195	0.060	0.148	1.493	0.575	8.39
11	0.000	0.091	1.219	0.061	0.151	1.523	0.534	8.92
12	0.000	0.093	1.243	0.062	0.154	1.553	0.495	9.42
13	0.000	0.095	1.268	0.063	0.157	1.584	0.459	9.88
14	0.000	0.097	1.294	0.065	0.160	1.616	0.425	10.30
15	0.000	0.099	1.319	0.066	0.164	1.648	0.395	10.70
16	0.000	0.101	1.346	0.067	0.167	1.681	0.366	11.06
17	0.000	0.103	1.373	0.069	0.170	1.715	0.339	11.40
18	0.000	0.105	1.400	0.070	0.174	1.749	0.315	11.72
19	0.000	0.107	1.428	0.071	0.177	1.784	0.292	12.01
20	0.000	0.109	1.457	0.073	0.181	1.820	0.270	12.28
21	0.000	0.111	1.486	0.074	0.184	1.856	0.251	12.53
22	0.000	0.114	1.516	0.076	0.188	1.893	0.233	12.76
23	0.000	0.116	1.546	0.077	0.192	1.931	0.216	12.98
24	0.000	0.118	1.577	0.079	0.196	1.970	0.200	13.18
25	0.000	0.121	1.608	0.080	0.199	2.009	0.185	13.36

Table 16: Operation & Maintenance cost of 316 Stainless steel for 25 year

9.2.3 COST ELEMENTS – 6MO STAINLESS STEEL MATERIAL (OPTION 3)

Capital cost Elements	Nok per meter/ weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	35000	3 500 000	Inhibitor cost	0
Flanges & Fittings		2 200 000	Inspection	50 000
Fabrication	13000	910 000	Man hour	1 000 000
Installation	500	50 000	Energy	50 000
Commisioning	500	50 000	Spares	350 000
Design & Admin	500	50 000		
Capital cost		6 760 000	Operating cost	1 450 000

Table 17: Life cycle Cost elements for 6Mo Stainless Steel

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for 6MO stainless steel (MNOK)								
Year	**Corrosion Inhibitor**	**Inspection**	**Man hour**	**Energy**	**Spare parts**	**Total**	**Present worth**	**PW Cummula-tive**
1	0.000	0.050	1.000	0.050	0.350	1.450	1.450	1.45
2	0.000	0.051	1.020	0.051	0.357	1.479	1.222	2.67
3	0.000	0.052	1.040	0.052	0.364	1.509	1.133	3.81
4	0.000	0.053	1.061	0.053	0.371	1.539	1.051	4.86
5	0.000	0.054	1.082	0.054	0.379	1.570	0.975	5.83
6	0.000	0.055	1.104	0.055	0.386	1.601	0.904	6.73
7	0.000	0.056	1.126	0.056	0.394	1.633	0.838	7.57
8	0.000	0.057	1.149	0.057	0.402	1.666	0.777	8.35
9	0.000	0.059	1.172	0.059	0.410	1.699	0.721	9.07
10	0.000	0.060	1.195	0.060	0.418	1.733	0.668	9.74
11	0.000	0.061	1.219	0.061	0.427	1.768	0.620	10.36
12	0.000	0.062	1.243	0.062	0.435	1.803	0.574	10.93
13	0.000	0.063	1.268	0.063	0.444	1.839	0.533	11.47
14	0.000	0.065	1.294	0.065	0.453	1.876	0.494	11.96
15	0.000	0.066	1.319	0.066	0.462	1.913	0.458	12.42
16	0.000	0.067	1.346	0.067	0.471	1.952	0.425	12.84
17	0.000	0.069	1.373	0.069	0.480	1.991	0.394	13.24
18	0.000	0.070	1.400	0.070	0.490	2.030	0.365	13.60
19	0.000	0.071	1.428	0.071	0.500	2.071	0.339	13.94
20	0.000	0.073	1.457	0.073	0.510	2.112	0.314	14.25
21	0.000	0.074	1.486	0.074	0.520	2.155	0.291	14.54
22	0.000	0.076	1.516	0.076	0.530	2.198	0.270	14.81
23	0.000	0.077	1.546	0.077	0.541	2.242	0.250	15.06
24	0.000	0.079	1.577	0.079	0.552	2.287	0.232	15.30
25	0.000	0.080	1.608	0.080	0.563	2.332	0.215	15.51

Table 18: Operation & Maintenance cost of 6Mo Stainless steel for 25 year

9.2.4 COST ELEMENTS – 22 CR DUPLEX STAINLESS STEEL MATERIAL (OPTION 4)

Capital cost Elements	Nok per meter/weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	29000	2 900 000	Inhibitor cost	0
Flanges & Fittings		800 000	Inspection	50 000
Fabrication	13000	910 000	Man hour	1 000 000
Installation	500	50 000	Energy	50 000
Commisioning	500	50 000	Spares	175 000
Design & Admin	500	50 000		
Capital cost		4 760 000	Operating cost	1 275 000

Table 19: Life cycle Cost elements for 22 Cr Duplex Stainless Steel

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for 22 CR Duplex stainless steel (MNOK)								
Year	Corrosion Inhibitor	Inspection	Man hour	Energy	Spare parts	Total	Present worth	PW Cummula-tive
1	0.000	0.050	1.000	0.050	0.175	1.275	1.275	1.28
2	0.000	0.051	1.020	0.051	0.179	1.301	1.075	2.35
3	0.000	0.052	1.040	0.052	0.182	1.327	0.997	3.35
4	0.000	0.053	1.061	0.053	0.186	1.353	0.924	4.27
5	0.000	0.054	1.082	0.054	0.189	1.380	0.857	5.13
6	0.000	0.055	1.104	0.055	0.193	1.408	0.795	5.92
7	0.000	0.056	1.126	0.056	0.197	1.436	0.737	6.66
8	0.000	0.057	1.149	0.057	0.201	1.465	0.683	7.34
9	0.000	0.059	1.172	0.059	0.205	1.494	0.634	7.98
10	0.000	0.060	1.195	0.060	0.209	1.524	0.587	8.56
11	0.000	0.061	1.219	0.061	0.213	1.554	0.545	9.11
12	0.000	0.062	1.243	0.062	0.218	1.585	0.505	9.61
13	0.000	0.063	1.268	0.063	0.222	1.617	0.468	10.08
14	0.000	0.065	1.294	0.065	0.226	1.649	0.434	10.52
15	0.000	0.066	1.319	0.066	0.231	1.682	0.403	10.92
16	0.000	0.067	1.346	0.067	0.236	1.716	0.373	11.29

17	0.000	0.069	1.373	0.069	0.240	1.750	0.346	11.64
18	0.000	0.070	1.400	0.070	0.245	1.785	0.321	11.96
19	0.000	0.071	1.428	0.071	0.250	1.821	0.298	12.26
20	0.000	0.073	1.457	0.073	0.255	1.857	0.276	12.53
21	0.000	0.074	1.486	0.074	0.260	1.895	0.256	12.79
22	0.000	0.076	1.516	0.076	0.265	1.932	0.237	13.03
23	0.000	0.077	1.546	0.077	0.271	1.971	0.220	13.25
24	0.000	0.079	1.577	0.079	0.276	2.011	0.204	13.45
25	0.000	0.080	1.608	0.080	0.281	2.051	0.189	13.64

Table 20: Operation & Maintenance cost of 22 Cr Duplex Stainless steel for 25 year

9.2.5 COST ELEMENTS – 25 CR DUPLEX STAINLESS STEEL MATERIAL (OPTION 5)

Capital cost Elements	Nok per meter/ weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	30000	3 000 000	Inhibitor cost	0
Flanges & Fittings		1 200 000	Inspection	50 000
Fabrication	13000	910 000	Man hour	1 000 000
Installation	500	50 000	Energy	50 000
Commisioning	500	50 000	Spares	250 000
Design & Admin	500	50 000		
Capital cost		5 260 000	Operating cost	1 350 000

Table 21: Life cycle Cost elements for 25 Cr Duplex Stainless Steel

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for 25 CR Duplex stainless steel (MNOK)								
Year	Corrosion Inhibitor	Inspection	Man hour	Energy	Spare parts	Total	Present worth	PW Cummula-tive
1	0.000	0.050	1.000	0.050	0.250	1.350	1.350	1.35
2	0.000	0.051	1.020	0.051	0.255	1.377	1.138	2.49
3	0.000	0.052	1.040	0.052	0.260	1.405	1.055	3.54
4	0.000	0.053	1.061	0.053	0.265	1.433	0.979	4.52

5	0.000	0.054	1.082	0.054	0.271	1.461	0.907	5.43
6	0.000	0.055	1.104	0.055	0.276	1.491	0.841	6.27
7	0.000	0.056	1.126	0.056	0.282	1.520	0.780	7.05
8	0.000	0.057	1.149	0.057	0.287	1.551	0.723	7.77
9	0.000	0.059	1.172	0.059	0.293	1.582	0.671	8.44
10	0.000	0.060	1.195	0.060	0.299	1.613	0.622	9.07
11	0.000	0.061	1.219	0.061	0.305	1.646	0.577	9.64
12	0.000	0.062	1.243	0.062	0.311	1.679	0.535	10.18
13	0.000	0.063	1.268	0.063	0.317	1.712	0.496	10.67
14	0.000	0.065	1.294	0.065	0.323	1.746	0.460	11.13
15	0.000	0.066	1.319	0.066	0.330	1.781	0.426	11.56
16	0.000	0.067	1.346	0.067	0.336	1.817	0.395	11.96
17	0.000	0.069	1.373	0.069	0.343	1.853	0.367	12.32
18	0.000	0.070	1.400	0.070	0.350	1.890	0.340	12.66
19	0.000	0.071	1.428	0.071	0.357	1.928	0.315	12.98
20	0.000	0.073	1.457	0.073	0.364	1.967	0.292	13.27
21	0.000	0.074	1.486	0.074	0.371	2.006	0.271	13.54
22	0.000	0.076	1.516	0.076	0.379	2.046	0.251	13.79
23	0.000	0.077	1.546	0.077	0.386	2.087	0.233	14.03
24	0.000	0.079	1.577	0.079	0.394	2.129	0.216	14.24
25	0.000	0.080	1.608	0.080	0.402	2.171	0.200	14.44

Table 22: Operation & Maintenance cost of 25 Cr Duplex Stainless steel for 25 year

9.2.6 COST ELEMENTS – TITANIUM MATERIAL (OPTION 6)

Capital cost Elements	Nok per meter/ weld	100m length (NOK)	Operating cost elements	Nok
Pipe Material	52000	5 200 000	Inhibitor cost	0
Flanges & Fittings		4 500 000	Inspection	0
Fabrication	15000	1 050 000	Man hour	1 000 000
Installation	500	50 000	Energy	50 000
Commisioning	500	50 000	Spares	800 000
Design & Admin	500	50 000		
Capital cost		10 900 000	Operating cost	1 850 000

Table 23: Life cycle Cost elements for Titanium

To deal with the uncertainties due to inflation 2% with discount rate 10%, Table have been prepared below for 25 years.

Operation & Maintenance Cost for Titanium (MNOK)								
Year	**Corrosion Inhibitor**	**Inspection**	**Man hour**	**Energy**	**Spare parts**	**Total**	**Present worth**	**PW Cummula-tive**
1	0.000	0.000	1.000	0.050	0.800	1.850	1.850	1.85
2	0.000	0.000	1.020	0.051	0.816	1.887	1.560	3.41
3	0.000	0.000	1.040	0.052	0.832	1.925	1.446	4.86
4	0.000	0.000	1.061	0.053	0.849	1.963	1.341	6.20
5	0.000	0.000	1.082	0.054	0.866	2.002	1.243	7.44
6	0.000	0.000	1.104	0.055	0.883	2.043	1.153	8.59
7	0.000	0.000	1.126	0.056	0.901	2.083	1.069	9.66
8	0.000	0.000	1.149	0.057	0.919	2.125	0.991	10.65
9	0.000	0.000	1.172	0.059	0.937	2.168	0.919	11.57
10	0.000	0.000	1.195	0.060	0.956	2.211	0.852	12.43
11	0.000	0.000	1.219	0.061	0.975	2.255	0.790	13.22
12	0.000	0.000	1.243	0.062	0.995	2.300	0.733	13.95
13	0.000	0.000	1.268	0.063	1.015	2.346	0.680	14.63
14	0.000	0.000	1.294	0.065	1.035	2.393	0.630	15.26
15	0.000	0.000	1.319	0.066	1.056	2.441	0.584	15.84
16	0.000	0.000	1.346	0.067	1.077	2.490	0.542	16.38
17	0.000	0.000	1.373	0.069	1.098	2.540	0.502	16.89
18	0.000	0.000	1.400	0.070	1.120	2.590	0.466	17.35
19	0.000	0.000	1.428	0.071	1.143	2.642	0.432	17.78
20	0.000	0.000	1.457	0.073	1.165	2.695	0.401	18.19
21	0.000	0.000	1.486	0.074	1.189	2.749	0.371	18.56
22	0.000	0.000	1.516	0.076	1.213	2.804	0.344	18.90
23	0.000	0.000	1.546	0.077	1.237	2.860	0.319	19.22
24	0.000	0.000	1.577	0.079	1.262	2.917	0.296	19.52
25	0.000	0.000	1.608	0.080	1.287	2.976	0.275	19.79

Table 24: Operation & Maintenance cost Titanium for 25 year

Capital cost (MNOK)					
Carbon steel	**316 sstl**	**6MO sstl**	**22Cr Dup**	**25Cr Dup**	**Titanium**
1.550	**4.385**	**6.760**	**4.760**	**5.260**	**10.900**

Table 25: Summary of Capital cost for different material selection

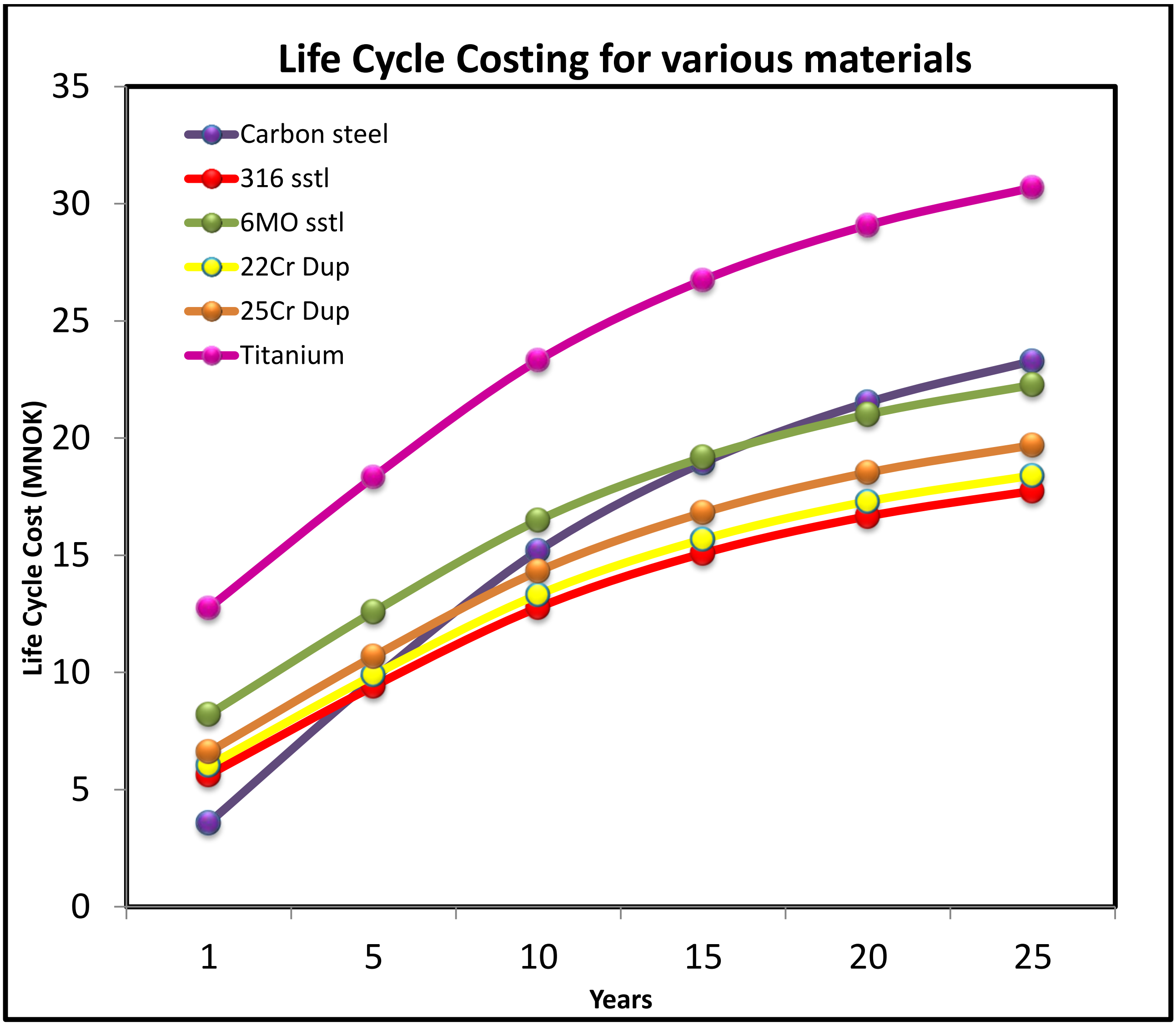
	Operation cost (MNOK)					
Years	**Carbon steel**	**316 sstl**	**6MO sstl**	**22Cr Dup**	**25Cr Dup**	**Titanium**
1	**2.03**	**1.25**	**1.45**	**1.28**	**1.35**	**1.85**
5	**8.17**	**5.02**	**5.83**	**5.13**	**5.43**	**7.44**
10	**13.65**	**8.39**	**9.74**	**8.56**	**9.07**	**12.43**
15	**17.40**	**10.70**	**12.42**	**10.92**	**11.56**	**15.84**
20	**19.97**	**12.28**	**14.25**	**12.53**	**13.27**	**18.19**
25	**21.74**	**13.36**	**15.51**	**13.64**	**14.44**	**19.79**

Table 26: Summary of Operational cost for different material selection

	LCC (MNOK)					
Years	**Carbon steel**	**316 sstl**	**6MO sstl**	**22Cr Dup**	**25Cr Dup**	**Titanium**
1	**3.58**	**5.63**	**8.21**	**6.04**	**6.61**	**12.75**
2	**5.29**	**6.69**	**9.43**	**7.11**	**7.75**	**14.31**
3	**6.88**	**7.66**	**10.57**	**8.11**	**8.80**	**15.76**
4	**8.36**	**8.57**	**11.62**	**9.03**	**9.78**	**17.10**
5	**9.72**	**9.41**	**12.59**	**9.89**	**10.69**	**18.34**
6	**10.99**	**10.19**	**13.49**	**10.68**	**11.53**	**19.49**
7	**12.16**	**10.91**	**14.33**	**11.42**	**12.31**	**20.56**
8	**13.25**	**11.58**	**15.11**	**12.10**	**13.03**	**21.55**
9	**14.26**	**12.20**	**15.83**	**12.74**	**13.70**	**22.47**
10	**15.20**	**12.77**	**16.50**	**13.32**	**14.33**	**23.33**
11	**16.07**	**13.31**	**17.12**	**13.87**	**14.90**	**24.12**
12	**16.87**	**13.80**	**17.69**	**14.37**	**15.44**	**24.85**
13	**17.62**	**14.26**	**18.23**	**14.84**	**15.93**	**25.53**
14	**18.31**	**14.69**	**18.72**	**15.28**	**16.39**	**26.16**
15	**18.95**	**15.08**	**19.18**	**15.68**	**16.82**	**26.74**

16	19.55	15.45	19.60	16.05	17.22	27.28
17	20.10	15.79	20.00	16.40	17.58	27.79
18	20.61	16.10	20.36	16.72	17.92	28.25
19	21.08	16.39	20.70	17.02	18.24	28.68
20	21.52	16.66	21.01	17.29	18.53	29.09
21	21.93	16.91	21.30	17.55	18.80	29.46
22	22.31	17.15	21.57	17.79	19.05	29.80
23	22.66	17.36	21.82	18.01	19.29	30.12
24	22.99	17.56	22.06	18.21	19.50	30.42
25	23.29	17.75	22.27	18.40	19.70	30.69

Table 27: **Summary of Life cycle cost for different material selection**



Graph 3: Graphical representation for comparison of LCC of Various materials

The graph above shows that carbon steel is considered to economical for first five years. After five years due to high operating cost the life cycle cost start increasing crosses 6MO stainless steel cost after 20 years. 316 stainless steel is lowest but because of high tendency towards stress cracking corrosion in flowlines it is not recommended. Titanium and 6Mo stainless steel and carbon steel has high life cycle cost for 25 years service life. With moderate life cycle cost and good corrosion properties 25% Cr Duplex stainless steel is considered to be best option for flowlines.

9.2.7 PW using Sensitivity analysis

Capital cost and operating cost year 1 from the table above is considered for calculating present worth using the equation mentioned below.

$$PW = -P + \left\{ \frac{t(P - S)}{n} \right\} (P / A..i\%.\ n) - (1 - t)(X)(P / A..i\%.\ n) + S(P / F.i\%.\ n)$$

Option 1: Carbon steel with inhibitor

Tax = 48%

Discount rate = 10%

Salvage value = 0

Using the capital recovery function (*P/A) mentioned in chapter* 8.2, the Value of Capital factor (P/A) is calculated as

Year	(P/A. i%. n)
5	3.792
10	6.153
15	7.604
20	8.525
25	9.09

Table 28: Capital recovery function (P/A)

By substituting the value of capital cost (P) as 1.55 Mnok (From table 25) and Operating cost (X) as 2.03 Mnok (From table 26) in the given equation.

Therefore,

$PW_{5\,Y} =$ $- 1.55 + ((0.48(1.55-0)/5))(3.792) – (1-0.48)(2.03)(3.792) + 0$

= -4.99 MNOK

$PW_{10\ Y}$ = -7.59 MNOK

$PW_{15\ Y}$ = -9.21 MNOK

$PW_{20\ Y}$ = -10.24 MNOK

PW_{25Y} = -10.88 MNOK

Annualized cost:

A = (PW) (A/P. i%. n)

The A/P factor for 10% interest rate is calculated for 5, 10, 15, 20 & 25 years are given in the table below.

Year	(A/P. i%. n)
5	0.2637
10	0.1625
15	0.1315
20	0.1173
25	0.1102

Table 29: **The capital recovery factor (*A/P*)**

$A_{5\ y}$ = -4.99 (0.2637)

= -1.32 MNOK

A_{10y} = -1.23 MNOK

A_{15y} = -1.21 MNOK

$A_{20\ y}$ = -1.20 MNOK

$A_{25\ y}$ = -1.20 MNOK

Similarly PW & A for other options are calculated. The values of PW and A for all options are summarized in table given below:

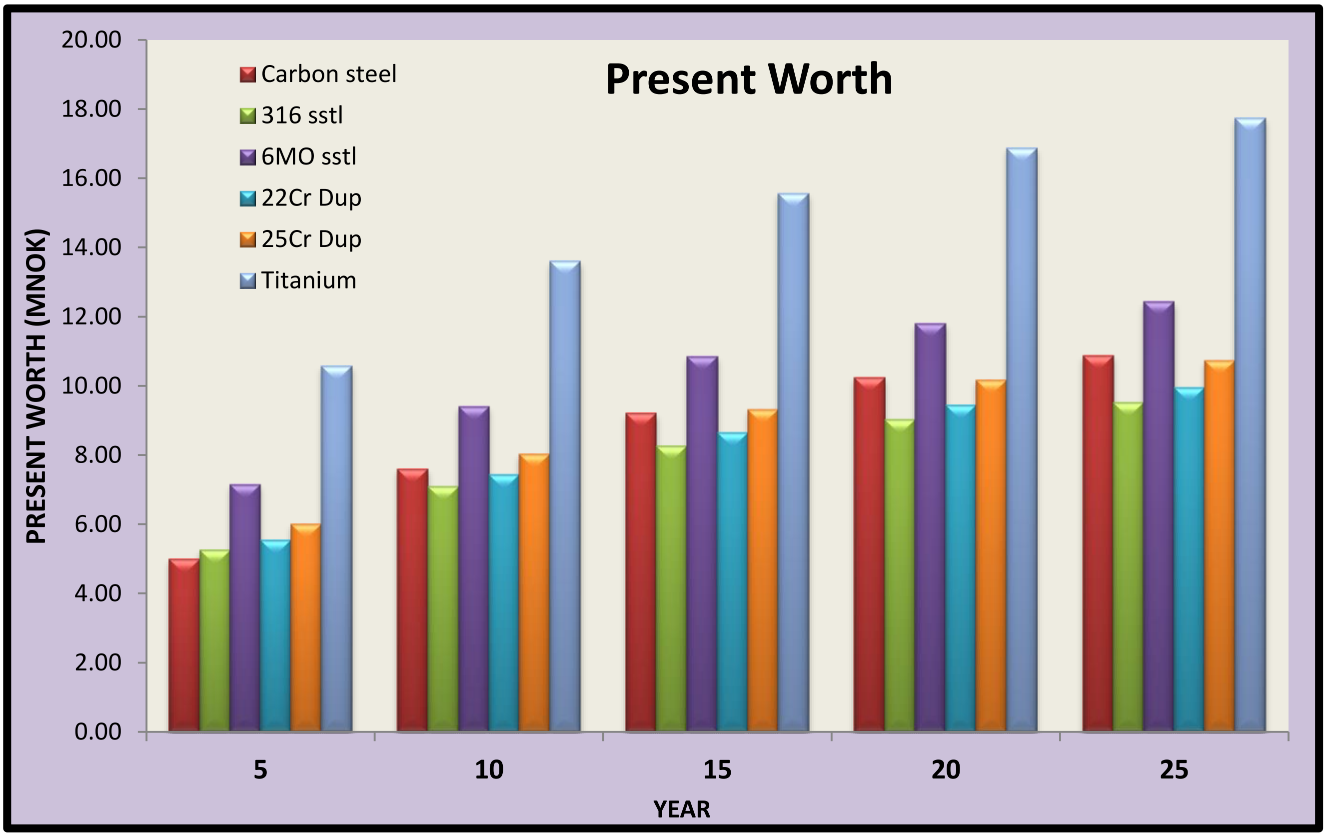
	Present worth (PW) (MNOK)					
Year	**Carbon steel**	**316 sstl**	**6MO sstl**	**22Cr Dup**	**25Cr Dup**	**Titanium**
5	4,99	5,25	7,16	5,54	6,01	10,58
10	7,59	7,09	9,40	7,43	8,03	13,60
15	9,21	8,26	10,85	8,64	9,32	15,56
20	10,24	9,02	11,80	9,44	10,17	16,87
25	10,88	9,52	12,43	9,96	10,72	17,74

Table 30: Summary of Present worth for various options

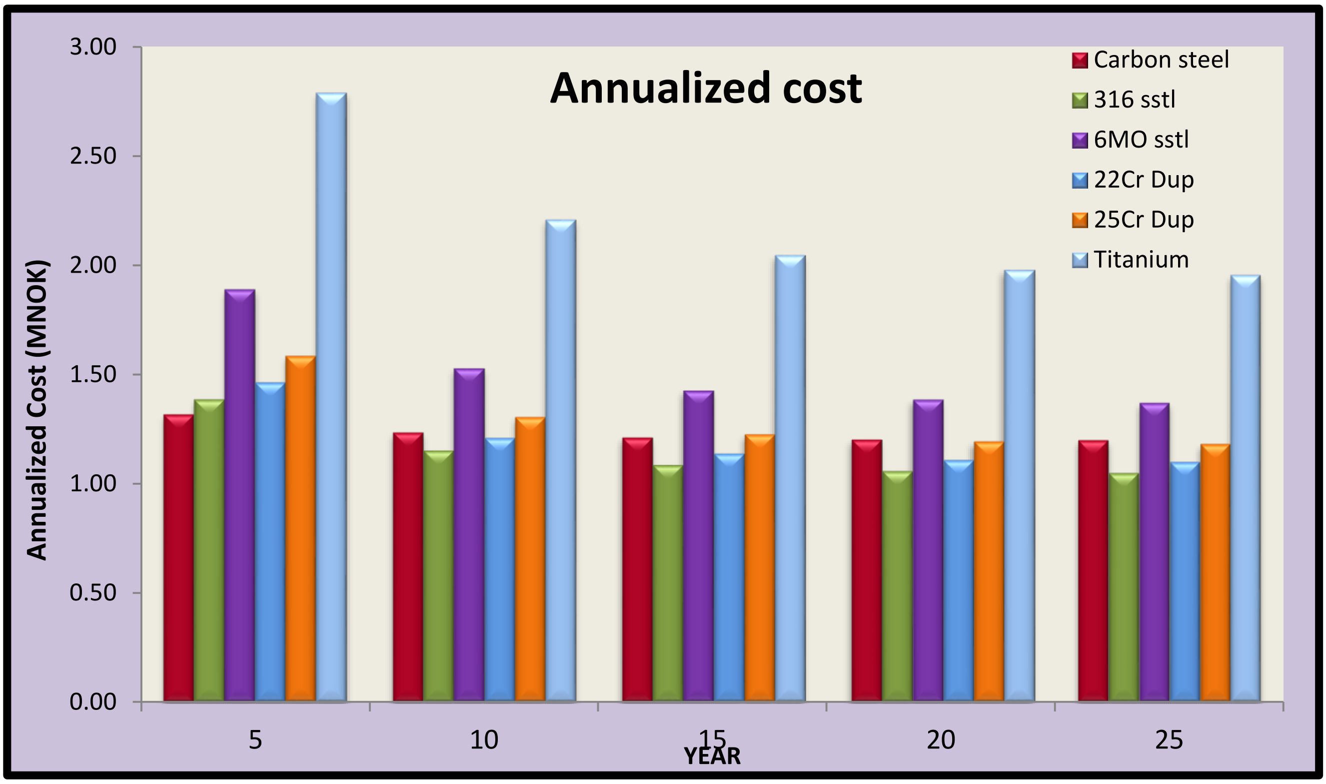
Similarly Annualized cost for various options are calculated and summarized in table given below:

	Table : Annualized cost (A) (MNOK)					
Year	Carbon steel	316 sstl	6MO sstl	22Cr Dup	25Cr Dup	Titanium
5	1,32	1,38	1,89	1,46	1,58	2,79
10	1,23	1,15	1,53	1,21	1,30	2,21
15	1,21	1,09	1,43	1,14	1,23	2,05
20	1,20	1,06	1,38	1,11	1,19	1,98
25	1,20	1,05	1,37	1,10	1,18	1,96

Table 31: Summary of Annualized cost for various options



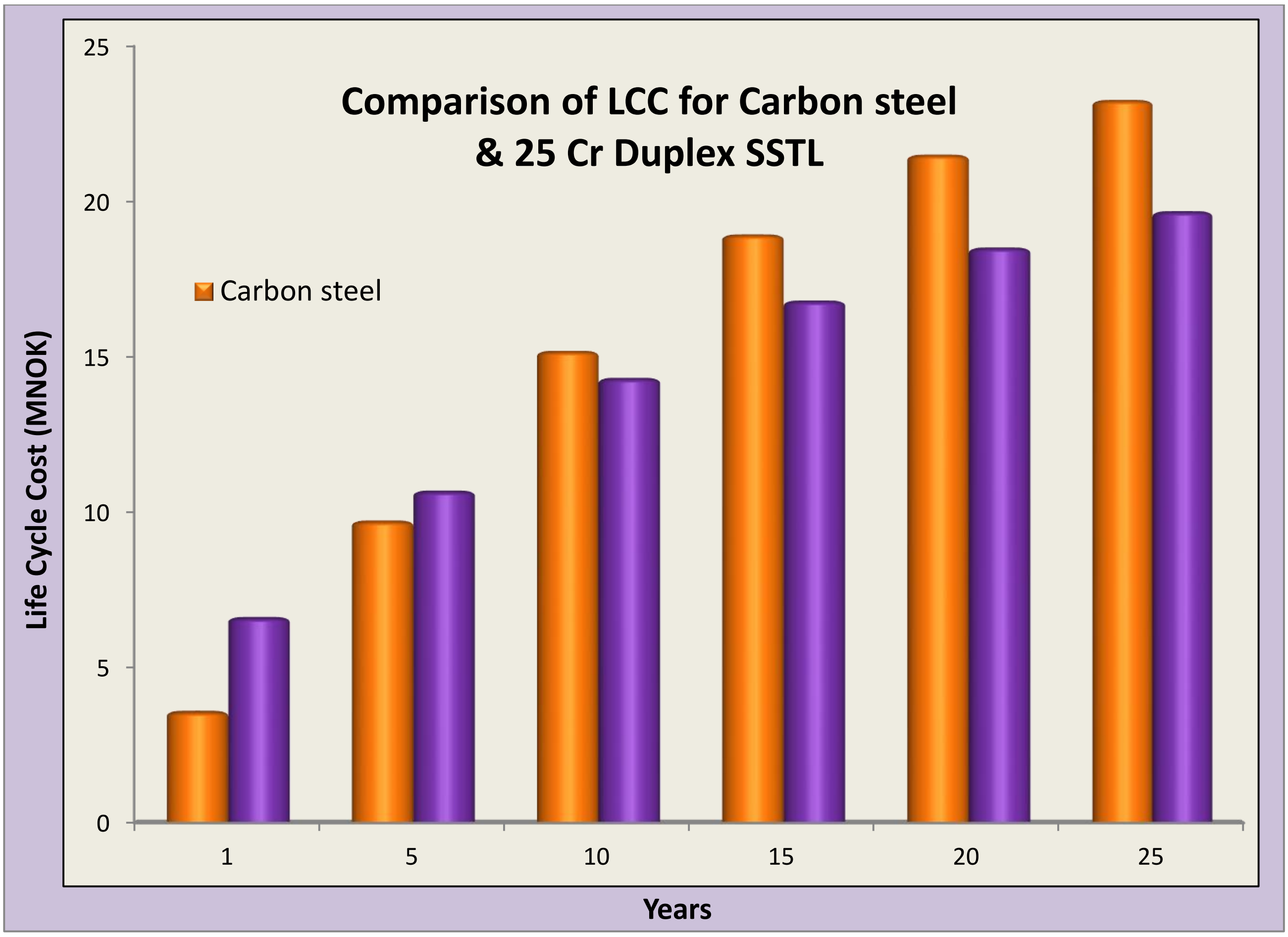
Graph 4: Graphical representation for comparison of PW of Various materials



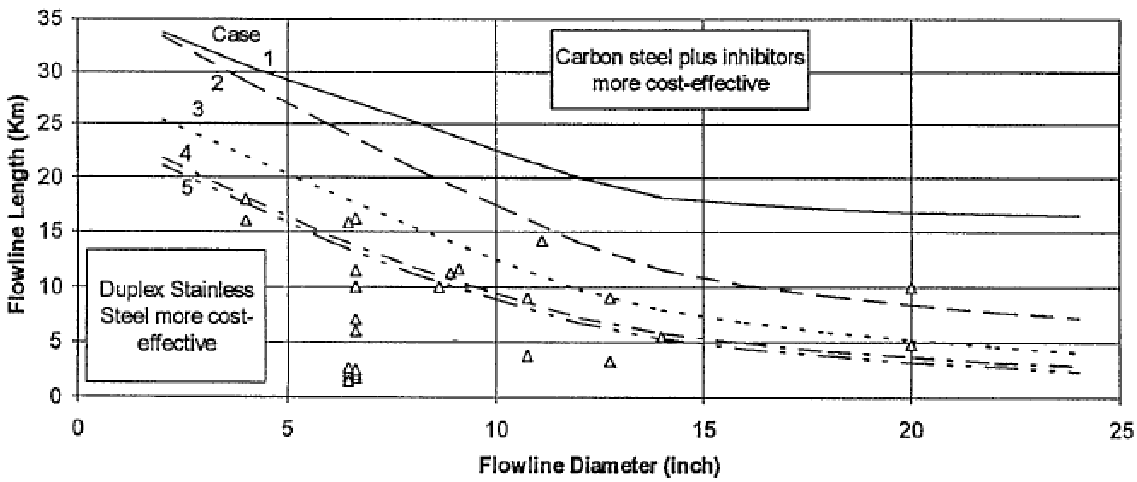
Graph 5: Graphical representation for comparison of Annualized cost of Various materials

9.2.8 COMPARISON BETWEEN CARBON STEEL AND DUPLEX STAINLESS STEEL

- Carbon steel Cost of Inhibitors and maintenance cost for inhibitor system adds to extra cost.
- Since the weight of Carbon steel Pipes are more than stainless steel alloys the transportation and logistics cost will be more.
- Carbon steel is more vulnerable to material loss due to corrosion hence more corrosion allowance has to be considered.
- Man power required for operating a Carbon steel Pipe line will be more in order to maintain and operate corrosion inhibitor system and carry out Inspections.
- Special Welding rods will increase fabrication costs in stainless steel alloy steels.
- Cost of Spares will be high for Corrosion resistant alloy due to high material costs.
- Energy cost is less for corrosion resistant alloy pipes. However the difference is very negligible.



Graph 6: Graphical representation for comparison of Life cycli cost between carbon steel & 25 Cr Duplex Stainless Steel

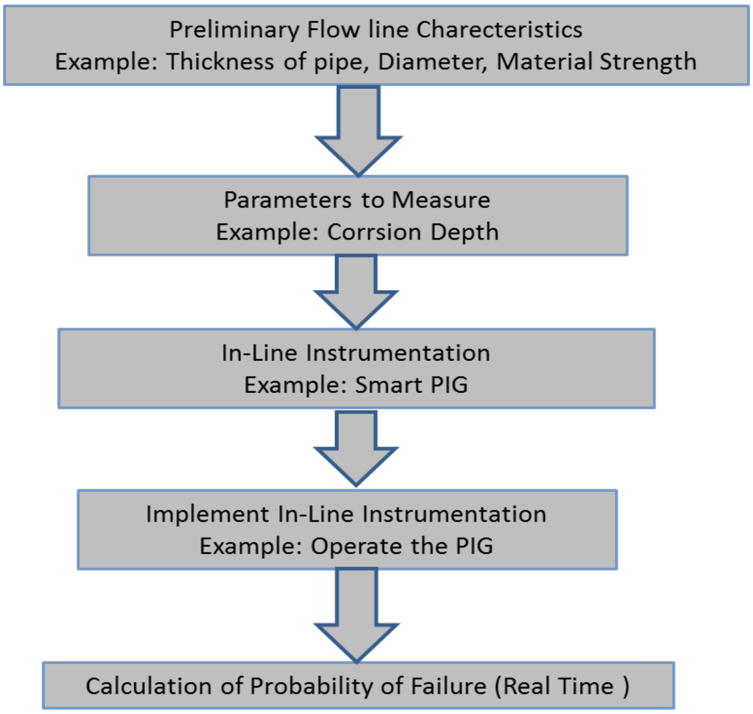


Graph 7: Carbon steel vs 22Cr Duplex Stainless Steel

(Source- L.M.Smith, M.Celant. Mac, 1995)

9.3 CARBON STEEL VS CORROSION RESISTANT ALLOYS WRT RELIABILITY

Over a period of years, in-line instrumentation has evolved for the assessing the real time reliability measurements of flow lines that can provide information to the asset management personnel with the paraphernalia to meet the maintenance needs of the flow line system. One of such characteristic is intelligent pig or smart pig that can quantify flow line characteristics and integrity using parameters such as burst pressure. Such an assessment of the pipeline is done using the following work process.



Flowchart 2: Calculating the probability of failure

(Source-Bea, et.al., 1998)

However, since corrosivity property in a pipeline is a function of time and the probability of failure is dependent on the time or in other words the amount of pipe corroded in a measured amount of time, the thickness of the flow line lost is dependent on the rate of corrosion. Therefore the performance of the flow line has to be evaluated for the elastic and plastic properties by characterizing wall thickness, corrosion rate through the calculation of internal pressure or in other words burst pressure. The probabilistic or deterministic model can then be used to calculate the probability of failure and therefore the reliability of the flow line. The following figure shows the probabilistic model of calculating the probability of failure.

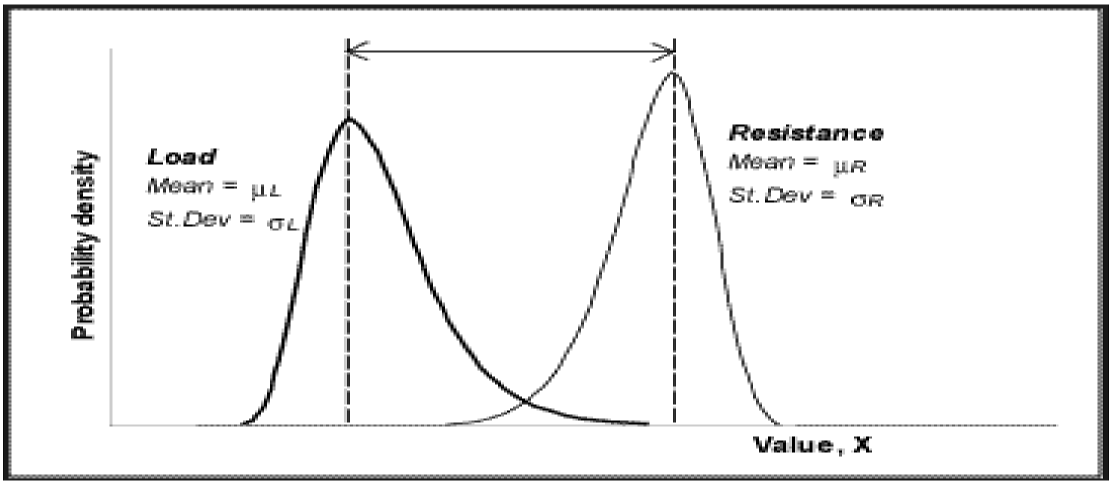


Figure 12: Probabilistic model of calculating the probability of failure

(Source-Bea, et.al., 1998)

The reliability assessment and management relies on the last step (calculation of probability of failure) for quantifying the status of the flow line and the necessary actions to be put forth. Such calculation take into account both the deterministic as well as probabilistic models as stated by (Bea, et.al., 1998). For the probabilistic model, reliability measure or in other words the safety index (β) can be calculated using

$$\beta = \frac{\ln\left(\frac{\underline{R}}{\underline{S}}\right)}{\sqrt{\sigma_{\ln R}^{2} + \sigma_{\ln S}^{2}}}$$

Where,

β = Safety Index

R = Median Capacity

S = Median Demand

R/S = median or central Factor of Safety

σlnR = Standard Deviation of the logarithms of the capacity (R)

σlnS = Standard Deviation of the logarithms of the demand (S)

The probability of failure for the standard Cumulative Normal Distribution probability of the variables is given by

$$P_f = 1 - \Phi(\beta)$$

$\Phi(\beta)$ = Cumulative Normal Distribution probability of the variables

Since the research involves in the selection of material for the flow line by excluding the possibility of using piggable operations, the corrosion or loss of pipe wall thickness as a result of corrosion must be calculated. For such an effort, the research adapted the equation suggested by Bea, et.al., (1998) which is based on the assumption that the flow line is subject to internal corrosion only as stated below.

Tci = αi * Vi * (Ls-Lp)

Where,

Tci =loss of wall thickness due to internal corrosion

αi =effectiveness of the inhibitor or protection

Vi=average corrosion rate

Ls=average service life of the pipeline

Lp = life of the initial protection provided to the pipeline

The loss of pipe wall thickness is analyzed for three scenarios

The following are the conditions or cases under which the corrosion effect or loss of pipe wall thickness is evaluated for:

CASE	Quantity of Wall Thickness Loss
A	Loss of internal pipe wall thickness = 30% of the wall thickness at the beginning of operation
B	Loss of internal pipe wall thickness = 60% of the wall thickness at the beginning of operation
C	Loss of internal pipe wall thickness = 90% of the wall thickness at the beginning of operation

Table 32: Conditions for corrosion effect or loss of pipe wall thickness

The efficiency of the inhibitor to as an important source for the mitigation of internal corrosion or ensure that there is no loss of flow line wall thickness are distributed qualitatively and represented quantitatively as described by Bea, et.al., (OTC, 1998). Even though, the flow lines are considered to be designed for operation for 25 years life, to demonstrate the operational service life effectiveness the researcher adapted the quantitative mapping of qualitative service life as shown in the table below.

Qualitative Inhibitor Efficiency	Quantitative Inhibitor Efficiency
Very Low	10
Low	8
Moderate	5
High	2
Very High	1

Table 33: Qualitative and Quantitative Inhibitor efficiency

Service Life Description	Average service life of the pipeline Or Life of the initial protection provided to the pipeline
Very Short	1
Short	5
Moderate	10
Long	15
Very Long	25

Table 34: Service life description

The NORSOK standard M-001 recommends the use of corrosion rate of the order 0.1mm/yr. for design purposes when there is no field or test data available, the researcher instead put forth a practical approach based on the calculated corrosion allowances for the material used for flowlines in different facilities. The corrosion rate for a service design life of 25 years is therefore calculated as shown in the table below for different materials.

Material	Service Life	Corrosion Allowance (mm)	Corrosion Rate (mm/yr.)	M-001 Recommended Corrosion Rate (mm/yr.)
Carbon Steel	25 Years	3	0.12	0.1
Stainless Steel	25 Years	1	0.04	0.1
6MO	25 Years	1	0.04	0.1
Duplex	25 Years	1	0.04	0.1
Super Duplex	25 Years	1	0.04	0.1
Titanium	25 Years	0	0.003	0.1

Table 35: Corrosion rate and allowance with respect to material

9.3.1 LOSS OF INTERNAL PIPE WALL THICKNESS FOR CARBON STEEL

The calculation results for the loss of internal pipe wall thickness for Carbon Steel is presented below for the 3 cases discussed earlier.

Case-A:

Loss of internal pipe wall thickness = 30% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	30% Of Actual Wall Thickness	Percentage Loss
0,12	10	25	0	30	7,62	393,70 %
0,12	8	25	0	24	7,62	314,96 %
0,12	5	25	0	15	7,62	196,85 %
0,12	2	25	0	6	7,62	78,74 %

0,12	1	25	0	3	7,62	39,37 %
0,12	10	25	5	24	7,62	314,96 %
0,12	8	25	5	19,2	7,62	251,97 %
0,12	5	25	5	12	7,62	157,48 %
0,12	2	25	5	4,8	7,62	62,99 %
0,12	1	25	5	2,4	7,62	31,50 %
0,12	10	25	10	18	7,62	236,22 %
0,12	8	25	10	14,4	7,62	188,98 %
0,12	5	25	10	9	7,62	118,11 %
0,12	2	25	10	3,6	7,62	47,24 %
0,12	1	25	10	1,8	7,62	23,62 %
0,12	10	25	15	12	7,62	157,48 %
0,12	8	25	15	9,6	7,62	125,98 %
0,12	5	25	15	6	7,62	78,74 %
0,12	2	25	15	2,4	7,62	31,50 %
0,12	1	25	15	1,2	7,62	15,75 %
0,12	10	25	20	6	7,62	78,74 %
0,12	8	25	20	4,8	7,62	62,99 %
0,12	5	25	20	3	7,62	39,37 %
0,12	2	25	20	1,2	7,62	15,75 %
0,12	1	25	20	0,6	7,62	7,87 %

Table 36: Loss of wall thickness Carbon steel Case A

Case-B:

Loss of internal pipe wall thickness = 60% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	60% Of Actual Wall Thickness	Percentage Loss
0,12	10	25	0	30	15,24	196,85 %
0,12	8	25	0	24	15,24	157,48 %
0,12	5	25	0	15	15,24	98,43 %
0,12	2	25	0	6	15,24	39,37 %
0,12	1	25	0	3	15,24	19,69 %
0,12	10	25	5	24	15,24	157,48 %
0,12	8	25	5	19,2	15,24	125,98 %
0,12	5	25	5	12	15,24	78,74 %
0,12	2	25	5	4,8	15,24	31,50 %
0,12	1	25	5	2,4	15,24	15,75 %
0,12	10	25	10	18	15,24	118,11 %
0,12	8	25	10	14,4	15,24	94,49 %
0,12	5	25	10	9	15,24	59,06 %
0,12	2	25	10	3,6	15,24	23,62 %
0,12	1	25	10	1,8	15,24	11,81 %
0,12	10	25	15	12	15,24	78,74 %
0,12	8	25	15	9,6	15,24	62,99 %
0,12	5	25	15	6	15,24	39,37 %
0,12	2	25	15	2,4	15,24	15,75 %
0,12	1	25	15	1,2	15,24	7,87 %
0,12	10	25	20	6	15,24	39,37 %
0,12	8	25	20	4,8	15,24	31,50 %
0,12	5	25	20	3	15,24	19,69 %
0,12	2	25	20	1,2	15,24	7,87 %
0,12	1	25	20	0,6	15,24	3,94 %

Table 37: Loss of wall thickness Carbon steel Case B

Case-C:

Loss of internal pipe wall thickness = 90% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	90% Of Actual Wall Thickness	Percentage Loss
0,12	10	25	0	30	22,86	131,23 %
0,12	8	25	0	24	22,86	104,99 %
0,12	5	25	0	15	22,86	65,62 %
0,12	2	25	0	6	22,86	26,25 %
0,12	1	25	0	3	22,86	13,12 %
0,12	10	25	5	24	22,86	104,99 %
0,12	8	25	5	19,2	22,86	83,99 %
0,12	5	25	5	12	22,86	52,49 %
0,12	2	25	5	4,8	22,86	21,00 %
0,12	1	25	5	2,4	22,86	10,50 %
0,12	10	25	10	18	22,86	78,74 %
0,12	8	25	10	14,4	22,86	62,99 %
0,12	5	25	10	9	22,86	39,37 %
0,12	2	25	10	3,6	22,86	15,75 %
0,12	1	25	10	1,8	22,86	7,87 %
0,12	10	25	15	12	22,86	52,49 %
0,12	8	25	15	9,6	22,86	41,99 %
0,12	5	25	15	6	22,86	26,25 %
0,12	2	25	15	2,4	22,86	10,50 %

0,12	1	25	15	1,2	22,86	5,25 %
0,12	10	25	20	6	22,86	26,25 %
0,12	8	25	20	4,8	22,86	21,00 %
0,12	5	25	20	3	22,86	13,12 %
0,12	2	25	20	1,2	22,86	5,25 %
0,12	1	25	20	0,6	22,86	2,62 %

Table 38: Loss of wall thickness Carbon steel Case C

9.3.2 LOSS OF INTERNAL PIPE WALL THICKNESS FOR 316 / 6Mo/ DUPLEX/ SUPER DUPLEX STAINLESS STEEL

The calculation results for the loss of internal pipe wall thickness for corrosion resistant alloys Stainless Steel, Duplex, Super Duplex is presented below for the 3 cases discussed earlier.

Case-A:

Loss of internal pipe wall thickness = 30% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Stainless Steel/Duplex/Super Duplex

Corrosion Rate = 0.04 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	30% Of Actual Wall Thickness	Percentage Loss
0,04	10	25	0	10	7,62	131,23 %
0,04	8	25	0	8	7,62	104,99 %
0,04	5	25	0	5	7,62	65,62 %
0,04	2	25	0	2	7,62	26,25 %
0,04	1	25	0	1	7,62	13,12 %
0,04	10	25	5	8	7,62	104,99 %
0,04	8	25	5	6,4	7,62	83,99 %
0,04	5	25	5	4	7,62	52,49 %

0,04	2	25	5	1,6	7,62	21,00 %
0,04	1	25	5	0,8	7,62	10,50 %
0,04	10	25	10	6	7,62	78,74 %
0,04	8	25	10	4,8	7,62	62,99 %
0,04	5	25	10	3	7,62	39,37 %
0,04	2	25	10	1,2	7,62	15,75 %
0,04	1	25	10	0,6	7,62	7,87 %
0,04	10	25	15	4	7,62	52,49 %
0,04	8	25	15	3,2	7,62	41,99 %
0,04	5	25	15	2	7,62	26,25 %
0,04	2	25	15	0,8	7,62	10,50 %
0,04	1	25	15	0,4	7,62	5,25 %
0,04	10	25	20	2	7,62	26,25 %
0,04	8	25	20	1,6	7,62	21,00 %
0,04	5	25	20	1	7,62	13,12 %
0,04	2	25	20	0,4	7,62	5,25 %
0,04	1	25	20	0,2	7,62	2,62 %

Table 39: Loss of wall thickness 316/Duplex/Super Duplex stainless steel Case A

Case-B:

Loss of internal pipe wall thickness = 60% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Stainless Steel/Duplex/Super Duplex

Corrosion Rate = 0.04 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	60% Of Actual Wall Thickness	Percentage Loss
0,04	10	25	0	10	15,24	65,62 %
0,04	8	25	0	8	15,24	52,49 %

0,04	5	25	0	5	15,24	32,81 %
0,04	2	25	0	2	15,24	13,12 %
0,04	1	25	0	1	15,24	6,56 %
0,04	10	25	5	8	15,24	52,49 %
0,04	8	25	5	6,4	15,24	41,99 %
0,04	5	25	5	4	15,24	26,25 %
0,04	2	25	5	1,6	15,24	10,50 %
0,04	1	25	5	0,8	15,24	5,25 %
0,04	10	25	10	6	15,24	39,37 %
0,04	8	25	10	4,8	15,24	31,50 %
0,04	5	25	10	3	15,24	19,69 %
0,04	2	25	10	1,2	15,24	7,87 %
0,04	1	25	10	0,6	15,24	3,94 %
0,04	10	25	15	4	15,24	26,25 %
0,04	8	25	15	3,2	15,24	21,00 %
0,04	5	25	15	2	15,24	13,12 %
0,04	2	25	15	0,8	15,24	5,25 %
0,04	1	25	15	0,4	15,24	2,62 %
0,04	10	25	20	2	15,24	13,12 %
0,04	8	25	20	1,6	15,24	10,50 %
0,04	5	25	20	1	15,24	6,56 %
0,04	2	25	20	0,4	15,24	2,62 %
0,04	1	25	20	0,2	15,24	1,31 %

Table 40: Loss of wall thickness 316/Duplex/Super Duplex stainless steel Case B

Case-C:

Loss of internal pipe wall thickness = 90% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Stainless Steel/Duplex/Super Duplex

Corrosion Rate = 0.04 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	90% Of Actual Wall Thickness	Percentage Loss
0,04	10	25	0	10	22,86	43,74 %
0,04	8	25	0	8	22,86	35,00 %
0,04	5	25	0	5	22,86	21,87 %
0,04	2	25	0	2	22,86	8,75 %
0,04	1	25	0	1	22,86	4,37 %
0,04	10	25	5	8	22,86	35,00 %
0,04	8	25	5	6,4	22,86	28,00 %
0,04	5	25	5	4	22,86	17,50 %
0,04	2	25	5	1,6	22,86	7,00 %
0,04	1	25	5	0,8	22,86	3,50 %
0,04	10	25	10	6	22,86	26,25 %
0,04	8	25	10	4,8	22,86	21,00 %
0,04	5	25	10	3	22,86	13,12 %
0,04	2	25	10	1,2	22,86	5,25 %
0,04	1	25	10	0,6	22,86	2,62 %
0,04	10	25	15	4	22,86	17,50 %
0,04	8	25	15	3,2	22,86	14,00 %
0,04	5	25	15	2	22,86	8,75 %
0,04	2	25	15	0,8	22,86	3,50 %
0,04	1	25	15	0,4	22,86	1,75 %
0,04	10	25	20	2	22,86	8,75 %
0,04	8	25	20	1,6	22,86	7,00 %
0,04	5	25	20	1	22,86	4,37 %
0,04	2	25	20	0,4	22,86	1,75 %
0,04	1	25	20	0,2	22,86	0,87 %

Table 41: Loss of wall thickness 316/Duplex/Super Duplex stainless steel Case C

9.3.3 LOSS OF INTERNAL PIPE WALL THICKNESS FOR TITANIUM

The calculation results for the loss of internal pipe wall thickness for corrosion resistant alloy titanium is presented below for the 3 cases discussed earlier.

Case-A:

Loss of internal pipe wall thickness = 30% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	30% Of Actual Wall Thickness	Percentage Loss
0,003	10	25	0	0,75	7,62	9,84 %
0,003	8	25	0	0,6	7,62	7,87 %
0,003	5	25	0	0,375	7,62	4,92 %
0,003	2	25	0	0,15	7,62	1,97 %
0,003	1	25	0	0,075	7,62	0,98 %
0,003	10	25	5	0,6	7,62	7,87 %
0,003	8	25	5	0,48	7,62	6,30 %
0,003	5	25	5	0,3	7,62	3,94 %
0,003	2	25	5	0,12	7,62	1,57 %
0,003	1	25	5	0,06	7,62	0,79 %
0,003	10	25	10	0,45	7,62	5,91 %
0,003	8	25	10	0,36	7,62	4,72 %
0,003	5	25	10	0,225	7,62	2,95 %
0,003	2	25	10	0,09	7,62	1,18 %
0,003	1	25	10	0,045	7,62	0,59 %
0,003	10	25	15	0,3	7,62	3,94 %
0,003	8	25	15	0,24	7,62	3,15 %

0,003	5	25	15	0,15	7,62	1,97 %
0,003	2	25	15	0,06	7,62	0,79 %
0,003	1	25	15	0,03	7,62	0,39 %
0,003	10	25	20	0,15	7,62	1,97 %
0,003	8	25	20	0,12	7,62	1,57 %
0,003	5	25	20	0,075	7,62	0,98 %
0,003	2	25	20	0,03	7,62	0,39 %
0,003	1	25	20	0,015	7,62	0,20 %

Table 42: Loss of wall thickness Titanium Case A

Case-B:

Loss of internal pipe wall thickness = 60% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	60% Of Actual Wall Thickness	Percentage Loss
0,003	10	25	0	0,75	15,24	4,92 %
0,003	8	25	0	0,6	15,24	3,94 %
0,003	5	25	0	0,375	15,24	2,46 %
0,003	2	25	0	0,15	15,24	0,98 %
0,003	1	25	0	0,075	15,24	0,49 %
0,003	10	25	5	0,6	15,24	3,94 %
0,003	8	25	5	0,48	15,24	3,15 %
0,003	5	25	5	0,3	15,24	1,97 %
0,003	2	25	5	0,12	15,24	0,79 %
0,003	1	25	5	0,06	15,24	0,39 %
0,003	10	25	10	0,45	15,24	2,95 %

0,003	8	25	10	0,36	15,24	2,36 %
0,003	5	25	10	0,225	15,24	1,48 %
0,003	2	25	10	0,09	15,24	0,59 %
0,003	1	25	10	0,045	15,24	0,30 %
0,003	10	25	15	0,3	15,24	1,97 %
0,003	8	25	15	0,24	15,24	1,57 %
0,003	5	25	15	0,15	15,24	0,98 %
0,003	2	25	15	0,06	15,24	0,39 %
0,003	1	25	15	0,03	15,24	0,20 %
0,003	10	25	20	0,15	15,24	0,98 %
0,003	8	25	20	0,12	15,24	0,79 %
0,003	5	25	20	0,075	15,24	0,49 %
0,003	2	25	20	0,03	15,24	0,20 %
0,003	1	25	20	0,015	15,24	0,10 %

Table 43: Loss of wall thickness Titanium Case B

Case-C:

Loss of internal pipe wall thickness = 90% of the wall thickness at the beginning of operation

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Corrosion Rate	Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss Of Wall Thickness	90% Of Actual Wall Thickness	Percentage Loss
0,003	10	25	0	0,75	22,86	3,28 %
0,003	8	25	0	0,6	22,86	2,62 %
0,003	5	25	0	0,375	22,86	1,64 %
0,003	2	25	0	0,15	22,86	0,66 %

0,003	1	25	0	0,075	22,86	0,33 %
0,003	10	25	5	0,6	22,86	2,62 %
0,003	8	25	5	0,48	22,86	2,10 %
0,003	5	25	5	0,3	22,86	1,31 %
0,003	2	25	5	0,12	22,86	0,52 %
0,003	1	25	5	0,06	22,86	0,26 %
0,003	10	25	10	0,45	22,86	1,97 %
0,003	8	25	10	0,36	22,86	1,57 %
0,003	5	25	10	0,225	22,86	0,98 %
0,003	2	25	10	0,09	22,86	0,39 %
0,003	1	25	10	0,045	22,86	0,20 %
0,003	10	25	15	0,3	22,86	1,31 %
0,003	8	25	15	0,24	22,86	1,05 %
0,003	5	25	15	0,15	22,86	0,66 %
0,003	2	25	15	0,06	22,86	0,26 %
0,003	1	25	15	0,03	22,86	0,13 %
0,003	10	25	20	0,15	22,86	0,66 %
0,003	8	25	20	0,12	22,86	0,52 %
0,003	5	25	20	0,075	22,86	0,33 %
0,003	2	25	20	0,03	22,86	0,13 %
0,003	1	25	20	0,015	22,86	0,07 %

Table 44: Loss of wall thickness Titanium Case C

In order to calculate the safety index and thereafter the probability of failure of the material exposed to corrosion, both deterministic as well as probabilistic has been adapted in this research. The following governing equations from the work of Bea (2000) have been adapted in this research for calculating the probabilistic burst pressure. For probabilistic burst pressure calculations the RAM pipe equation by Bea and Xu (1999) has been adapted.

$$P_B = \frac{SMTS \cdot t}{R}$$

Where,

Pb = Burst Pressure

SMTS= Specified Minimum Tensile Strength

t = wall thickness

R = Radius

$$p_{bd} = \frac{3.2 \cdot t_{nom} \cdot SMYS}{D_o \cdot SCF}$$

Where,

Pbd = Burst Pressure of Corroded Pipe

Tnom = Noninal Pipe Wall Thickness

SMYS = Specified Minimum Yield Strength of the Pipeline Material

SCF = Stress Concentration factor = 1 + 2*(d/R)^0.5

R = Radius of the Pipe

The following table presents the minimum yield strength and minimum tensile strength of the materials considered in this research for evaluation.

Material	Specified Minimum Yield Strength of the Pipeline Material (SMYS) (Psi)	Specified Minimum Tensile Strength (SMTS) (Psi)
Carbon Steel (Gr.B)	42000	52000
Stainless Steel (Gr.316)	29732	74694
6MO(UNS N08367)	55000	107000
Duplex (UNS S31803)	65000	95000
Super Duplex(UNS S33750)	80000	116000
Titanium (UNS R50250)	25000	35000

Table 45: Shows minimum yield strength and minimum tensile strength of the materials

9.3.4 PROBABILITY OF FAILURE FOR CARBON STEEL

The calculation results for the probability of failure for carbon steel material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	Average service life of the pipeline	Life of the initial protection provided to the pipeline	Specified Minimum Yield Strength (SMYS) (KPSI)	Depth Of Corrosion	Stress Concentration Factor	Probabilistic Burst Pressure Corroded (PBD) (KPsi)	Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)	Deterministic Burst Pressure (PB) (KPsi)	Standard Variance	Safety Index (β)	Probability of Failure
10	25	0	42,00	30	1,86	8,37	52	8,16	0,48	0,05	0,48
8	25	0	42,00	24	1,77	8,80	52	8,16	0,48	0,16	0,44
5	25	0	42,00	15	1,61	9,69	52	8,16	0,48	0,36	0,36
2	25	0	42,00	6	1,38	11,25	52	8,16	0,48	0,67	0,25
1	25	0	42,00	3	1,27	12,25	52	8,16	0,48	0,84	0,20
10	25	5	42,00	24	1,77	8,80	52	8,16	0,48	0,16	0,44
8	25	5	42,00	19,2	1,69	9,23	52	8,16	0,48	0,26	0,40
5	25	5	42,00	12	1,54	10,09	52	8,16	0,48	0,44	0,33
2	25	5	42,00	4,8	1,34	11,59	52	8,16	0,48	0,73	0,23
1	25	5	42,00	2,4	1,24	12,53	52	8,16	0,48	0,89	0,19
10	25	10	42,00	18	1,67	9,35	52	8,16	0,48	0,28	0,39
8	25	10	42,00	14,4	1,60	9,76	52	8,16	0,48	0,37	0,36
5	25	10	42,00	9	1,47	10,59	52	8,16	0,48	0,54	0,29
2	25	10	42,00	3,6	1,30	12,00	52	8,16	0,48	0,80	0,21
1	25	10	42,00	1,8	1,21	12,87	52	8,16	0,48	0,94	0,17

10	25	15	42,00	12	1,54	10,09	52	8,16	0,48	0,44	0,33
8	25	15	42,00	9,6	1,49	10,48	52	8,16	0,48	0,52	0,30
5	25	15	42,00	6	1,38	11,25	52	8,16	0,48	0,67	0,25
2	25	15	42,00	2,4	1,24	12,53	52	8,16	0,48	0,89	0,19
1	25	15	42,00	1,2	1,17	13,29	52	8,16	0,48	1,01	0,16
10	25	20	42,00	6	1,38	11,25	52	8,16	0,48	0,67	0,25
8	25	20	42,00	4,8	1,34	11,59	52	8,16	0,48	0,73	0,23
5	25	20	42,00	3	1,27	12,25	52	8,16	0,48	0,84	0,20
2	25	20	42,00	1,2	1,17	13,29	52	8,16	0,48	1,01	0,16
1	25	20	42,00	0,6	1,12	13,89	52	8,16	0,48	1,10	0,14

Table 46: Showing probability of failure for carbon steel material

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
2	25	0	6	23,6 %	0,25
1	25	0	3	11,8 %	0,20
2	25	5	4,8	18,9 %	0,23
1	25	5	2,4	9,4 %	0,19
2	25	10	3,6	14,2 %	0,21
1	25	10	1,8	7,1 %	0,17
5	25	15	6	23,6 %	0,25
2	25	15	2,4	9,4 %	0,19
1	25	15	1,2	4,7 %	0,16
10	25	20	6	23,6 %	0,25
8	25	20	4,8	18,9 %	0,23
5	25	20	3	11,8 %	0,20
2	25	20	1,2	4,7 %	0,16
1	25	20	0,6	2,4 %	0,14

Table 47: Carbon steel case A - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
5	25	0	15	59,1 %	0,36
2	25	0	6	23,6 %	0,25
1	25	0	3	11,8 %	0,20
5	25	5	12	47,2 %	0,33
2	25	5	4,8	18,9 %	0,23
1	25	5	2,4	9,4 %	0,19
8	25	10	14,4	56,7 %	0,36
5	25	10	9	35,4 %	0,29
2	25	10	3,6	14,2 %	0,21
1	25	10	1,8	7,1 %	0,17
10	25	15	12	47,2 %	0,33
8	25	15	9,6	37,8 %	0,30
5	25	15	6	23,6 %	0,25
2	25	15	2,4	9,4 %	0,19
1	25	15	1,2	4,7 %	0,16
10	25	20	6	23,6 %	0,25
8	25	20	4,8	18,9 %	0,23
5	25	20	3	11,8 %	0,20
2	25	20	1,2	4,7 %	0,16
1	25	20	0,6	2,4 %	0,14

Table 48: Carbon steel Case B - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Carbon Steel

Corrosion Rate = 0.12 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
5	25	0	15	59,1 %	0,36
2	25	0	6	23,6 %	0,25
1	25	0	3	11,8 %	0,20
8	25	5	19,2	75,6 %	0,40
5	25	5	12	47,2 %	0,33
2	25	5	4,8	18,9 %	0,23
1	25	5	2,4	9,4 %	0,19
10	25	10	18	70,9 %	0,39
8	25	10	14,4	56,7 %	0,36
5	25	10	9	35,4 %	0,29
2	25	10	3,6	14,2 %	0,21
1	25	10	1,8	7,1 %	0,17
10	25	15	12	47,2 %	0,33
8	25	15	9,6	37,8 %	0,30
5	25	15	6	23,6 %	0,25
2	25	15	2,4	9,4 %	0,19
1	25	15	1,2	4,7 %	0,16
10	25	20	6	23,6 %	0,25
8	25	20	4,8	18,9 %	0,23

5	25	20	3	11,8 %	0,20
2	25	20	1,2	4,7 %	0,16
1	25	20	0,6	2,4 %	0,14

Table 49: Carbon steel Case C - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

9.3.5 PROBABILITY OF FAILURE FOR 316 STAINLESS STEEL

The calculation results for the probability of failure for Stainless Steel material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	**Average service life of the pipeline**	**Life of the initial protection provided to the pipeline**	**Specified Minimum Yield Strength (SMYS) (KPSI)**	**Depth Of Corrosion**	**Stress Concentration Factor**	**Probabilistic Burst Pressure Corroded (PBD) (KPsi)**	**Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)**	**Deterministic Burst Pressure (PB) (KPsi)**	**Standard Variance**	**Safety Index (β)**	**Probability of Failure**
10	25	0	29,73	10	1,50	7,37	74,69	11,71	0,48	-0,96	0,83
8	25	0	29,73	8	1,44	7,64	74,69	11,71	0,48	-0,89	0,81
5	25	0	29,73	5	1,35	8,16	74,69	11,71	0,48	-0,75	0,77
2	25	0	29,73	2	1,22	9,02	74,69	11,71	0,48	-0,54	0,71
1	25	0	29,73	1	1,16	9,53	74,69	11,71	0,48	-0,43	0,67
10	25	5	29,73	8	1,44	7,64	74,69	11,71	0,48	-0,89	0,81
8	25	5	29,73	6,4	1,40	7,89	74,69	11,71	0,48	-0,82	0,79
5	25	5	29,73	4	1,31	8,39	74,69	11,71	0,48	-0,69	0,75
2	25	5	29,73	1,6	1,20	9,20	74,69	11,71	0,48	-0,50	0,69
1	25	5	29,73	0,8	1,14	9,67	74,69	11,71	0,48	-0,40	0,65
10	25	10	29,73	6	1,38	7,96	74,69	11,71	0,48	-0,80	0,79

8	25	10	29,73	4,8	1,34	8,21	74,69	11,71	0,48	-0,74	0,77
5	25	10	29,73	3	1,27	8,67	74,69	11,71	0,48	-0,62	0,73
2	25	10	29,73	1,2	1,17	9,41	74,69	11,71	0,48	-0,45	0,67
1	25	10	29,73	0,6	1,12	9,83	74,69	11,71	0,48	-0,36	0,64
10	25	15	29,73	4	1,31	8,39	74,69	11,71	0,48	-0,69	0,75
8	25	15	29,73	3,2	1,28	8,61	74,69	11,71	0,48	-0,64	0,74
5	25	15	29,73	2	1,22	9,02	74,69	11,71	0,48	-0,54	0,71
2	25	15	29,73	0,8	1,14	9,67	74,69	11,71	0,48	-0,40	0,65
1	25	15	29,73	0,4	1,10	10,03	74,69	11,71	0,48	-0,32	0,63
10	25	20	29,73	2	1,22	9,02	74,69	11,71	0,48	-0,54	0,71
8	25	20	29,73	1,6	1,20	9,20	74,69	11,71	0,48	-0,50	0,69
5	25	20	29,73	1	1,16	9,53	74,69	11,71	0,48	-0,43	0,67
2	25	20	29,73	0,4	1,10	10,03	74,69	11,71	0,48	-0,32	0,63
1	25	20	29,73	0,2	1,07	10,31	74,69	11,71	0,48	-0,26	0,60

Table 50: Shows the probability of failure for 316 Stainless Steel

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 316 Stainless Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
5	25	0	5	19,7 %	0,77
2	25	0	2	7,9 %	0,71
1	25	0	1	3,9 %	0,67
8	25	5	6,4	25,2 %	0,79
5	25	5	4	15,7 %	0,75
2	25	5	1,6	6,3 %	0,69
1	25	5	0,8	3,1 %	0,65
10	25	10	6	23,6 %	0,79
8	25	10	4,8	18,9 %	0,77
5	25	10	3	11,8 %	0,73
2	25	10	1,2	4,7 %	0,67
1	25	10	0,6	2,4 %	0,64
10	25	15	4	15,7 %	0,75
8	25	15	3,2	12,6 %	0,74
5	25	15	2	7,9 %	0,71
2	25	15	0,8	3,1 %	0,65
1	25	15	0,4	1,6 %	0,63
10	25	20	2	7,9 %	0,71
8	25	20	1,6	6,3 %	0,69
5	25	20	1	3,9 %	0,67

2	25	20	0,4	1,6 %	0,63
1	25	20	0,2	0,8 %	0,60

Table 51: 316 Stainless steel Case A - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 316 Stainless Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,83
8	25	0	8	31,5 %	0,81
5	25	0	5	19,7 %	0,77
2	25	0	2	7,9 %	0,71
1	25	0	1	3,9 %	0,67
10	25	5	8	31,5 %	0,81
8	25	5	6,4	25,2 %	0,79
5	25	5	4	15,7 %	0,75
2	25	5	1,6	6,3 %	0,69
1	25	5	0,8	3,1 %	0,65
10	25	10	6	23,6 %	0,79
8	25	10	4,8	18,9 %	0,77
5	25	10	3	11,8 %	0,73
2	25	10	1,2	4,7 %	0,67

1	25	10	0,6	2,4 %	0,64
10	25	15	4	15,7 %	0,75
8	25	15	3,2	12,6 %	0,74
5	25	15	2	7,9 %	0,71
2	25	15	0,8	3,1 %	0,65
1	25	15	0,4	1,6 %	0,63
10	25	20	2	7,9 %	0,71
8	25	20	1,6	6,3 %	0,69
5	25	20	1	3,9 %	0,67
2	25	20	0,4	1,6 %	0,63
1	25	20	0,2	0,8 %	0,60

Table 52: 316 Stainless steel Case B - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 316 Stainless Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,83
8	25	0	8	31,5 %	0,81
5	25	0	5	19,7 %	0,77
2	25	0	2	7,9 %	0,71

1	25	0	1	3,9 %	0,67
10	25	5	8	31,5 %	0,81
8	25	5	6,4	25,2 %	0,79
5	25	5	4	15,7 %	0,75
2	25	5	1,6	6,3 %	0,69
1	25	5	0,8	3,1 %	0,65
10	25	10	6	23,6 %	0,79
8	25	10	4,8	18,9 %	0,77
5	25	10	3	11,8 %	0,73
2	25	10	1,2	4,7 %	0,67
1	25	10	0,6	2,4 %	0,64
10	25	15	4	15,7 %	0,75
8	25	15	3,2	12,6 %	0,74
5	25	15	2	7,9 %	0,71
2	25	15	0,8	3,1 %	0,65
1	25	15	0,4	1,6 %	0,63
10	25	20	2	7,9 %	0,71
8	25	20	1,6	6,3 %	0,69
5	25	20	1	3,9 %	0,67
2	25	20	0,4	1,6 %	0,63
1	25	20	0,2	0,8 %	0,60

Table 53: 316 Stainless steel Case C - Shows the correlation between the efficiency of inhibitor required and the life of initial protection required

9.3.6 PROBABILITY OF FAILURE FOR 6MO STEEL

The calculation results for the probability of failure for 6Mo Steel material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	Average service life of the pipeline	Life of the initial protection provided to the pipeline	Specified Minimum Yield Strength (SMYS) (KPSI)	Depth Of Corrosion	Stress Concentration Factor	Probabilistic Burst Pressure Corroded (PBD) (KPsi)	Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)	Deterministic Burst Pressure (PB) (KPsi)	Standard Variance	Safety Index (β)	Probability of Failure
10	25	0	55,00	10	1,50	13,63	107	16,78	0,48	-0,43	0,67
8	25	0	55,00	8	1,44	14,13	107	16,78	0,48	-0,36	0,64
5	25	0	55,00	5	1,35	15,10	107	16,78	0,48	-0,22	0,59
2	25	0	55,00	2	1,22	16,70	107	16,78	0,48	-0,01	0,50
1	25	0	55,00	1	1,16	17,63	107	16,78	0,48	0,10	0,46
10	25	5	55,00	8	1,44	14,13	107	16,78	0,48	-0,36	0,64
8	25	5	55,00	6,4	1,40	14,60	107	16,78	0,48	-0,29	0,61
5	25	5	55,00	4	1,31	15,53	107	16,78	0,48	-0,16	0,56
2	25	5	55,00	1,6	1,20	17,02	107	16,78	0,48	0,03	0,49
1	25	5	55,00	0,8	1,14	17,89	107	16,78	0,48	0,13	0,45
10	25	10	55,00	6	1,38	14,73	107	16,78	0,48	-0,27	0,61
8	25	10	55,00	4,8	1,34	15,18	107	16,78	0,48	-0,21	0,58
5	25	10	55,00	3	1,27	16,04	107	16,78	0,48	-0,09	0,54
2	25	10	55,00	1,2	1,17	17,41	107	16,78	0,48	0,08	0,47

1	25	10	55,00	0,6	1,12	18,19	107	16,78	0,48	0,17	0,43
10	25	15	55,00	4	1,31	15,53	107	16,78	0,48	-0,16	0,56
8	25	15	55,00	3,2	1,28	15,93	107	16,78	0,48	-0,11	0,54
5	25	15	55,00	2	1,22	16,70	107	16,78	0,48	-0,01	0,50
2	25	15	55,00	0,8	1,14	17,89	107	16,78	0,48	0,13	0,45
1	25	15	55,00	0,4	1,10	18,56	107	16,78	0,48	0,21	0,42
10	25	20	55,00	2	1,22	16,70	107	16,78	0,48	-0,01	0,50
8	25	20	55,00	1,6	1,20	17,02	107	16,78	0,48	0,03	0,49
5	25	20	55,00	1	1,16	17,63	107	16,78	0,48	0,10	0,46
2	25	20	55,00	0,4	1,10	18,56	107	16,78	0,48	0,21	0,42
1	25	20	55,00	0,2	1,07	19,07	107	16,78	0,48	0,26	0,40

Table 54: Shows the probability of failure for 6Mo stainless Steel

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 6Mo Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
5	25	0	5	19,7 %	0,59
2	25	0	2	7,9 %	0,50
1	25	0	1	3,9 %	0,46
8	25	5	6,4	25,2 %	0,61
5	25	5	4	15,7 %	0,56
2	25	5	1,6	6,3 %	0,49
1	25	5	0,8	3,1 %	0,45
10	25	10	6	23,6 %	0,61
8	25	10	4,8	18,9 %	0,58
5	25	10	3	11,8 %	0,54
2	25	10	1,2	4,7 %	0,47
1	25	10	0,6	2,4 %	0,43
10	25	15	4	15,7 %	0,56
8	25	15	3,2	12,6 %	0,54
5	25	15	2	7,9 %	0,50
2	25	15	0,8	3,1 %	0,45
1	25	15	0,4	1,6 %	0,42
10	25	20	2	7,9 %	0,50
8	25	20	1,6	6,3 %	0,49

5	25	20	1	3,9 %	0,46
2	25	20	0,4	1,6 %	0,42
1	25	20	0,2	0,8 %	0,40

Table 55: 6Mo Stainless steel Case A- the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 6Mo Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,67
8	25	0	8	31,5 %	0,64
5	25	0	5	19,7 %	0,59
2	25	0	2	7,9 %	0,50
1	25	0	1	3,9 %	0,46
10	25	5	8	31,5 %	0,64
8	25	5	6,4	25,2 %	0,61
5	25	5	4	15,7 %	0,56
2	25	5	1,6	6,3 %	0,49
1	25	5	0,8	3,1 %	0,45
10	25	10	6	23,6 %	0,61
8	25	10	4,8	18,9 %	0,58
5	25	10	3	11,8 %	0,54

2	25	10	1,2	4,7 %	0,47
1	25	10	0,6	2,4 %	0,43
10	25	15	4	15,7 %	0,56
8	25	15	3,2	12,6 %	0,54
5	25	15	2	7,9 %	0,50
2	25	15	0,8	3,1 %	0,45
1	25	15	0,4	1,6 %	0,42
10	25	20	2	7,9 %	0,50
8	25	20	1,6	6,3 %	0,49
5	25	20	1	3,9 %	0,46
2	25	20	0,4	1,6 %	0,42
1	25	20	0,2	0,8 %	0,40

Table 56: 6Mo Stainless steel Case B- the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = 6Mo Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,67
8	25	0	8	31,5 %	0,64
5	25	0	5	19,7 %	0,59
2	25	0	2	7,9 %	0,50

1	25	0	1	3,9 %	0,46
10	25	5	8	31,5 %	0,64
8	25	5	6,4	25,2 %	0,61
5	25	5	4	15,7 %	0,56
2	25	5	1,6	6,3 %	0,49
1	25	5	0,8	3,1 %	0,45
10	25	10	6	23,6 %	0,61
8	25	10	4,8	18,9 %	0,58
5	25	10	3	11,8 %	0,54
2	25	10	1,2	4,7 %	0,47
1	25	10	0,6	2,4 %	0,43
10	25	15	4	15,7 %	0,56
8	25	15	3,2	12,6 %	0,54
5	25	15	2	7,9 %	0,50
2	25	15	0,8	3,1 %	0,45
1	25	15	0,4	1,6 %	0,42
10	25	20	2	7,9 %	0,50
8	25	20	1,6	6,3 %	0,49
5	25	20	1	3,9 %	0,46
2	25	20	0,4	1,6 %	0,42
1	25	20	0,2	0,8 %	0,40

Table 57: 6Mo Stainless steel Case C- the correlation between the efficiency of inhibitor required and the life of initial protection required

9.3.7 PROBABILITY OF FAILURE FOR DUPLEX STEEL

The calculation results for the probability of failure for Duplex Steel material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	Average service life of the pipeline	Life of the initial protection provided to the pipeline	Specified Minimum Yield Strength (SMYS) (KPSI)	Depth Of Corrosion	Stress Concentration Factor	Probabilistic Burst Pressure Corroded (PBD) (KPsi)	Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)	Deterministic Burst Pressure (PB) (KPsi)	Standard Variance	Safety Index (β)	Probability of Failure
10	25	0	65,00	10	1,50	16,11	65	10,19	0,48	0,95	0,17
8	25	0	65,00	8	1,44	16,69	65	10,19	0,48	1,02	0,15
5	25	0	65,00	5	1,35	17,84	65	10,19	0,48	1,16	0,12
2	25	0	65,00	2	1,22	19,73	65	10,19	0,48	1,37	0,09
1	25	0	65,00	1	1,16	20,84	65	10,19	0,48	1,48	0,07
10	25	5	65,00	8	1,44	16,69	65	10,19	0,48	1,02	0,15
8	25	5	65,00	6,4	1,40	17,26	65	10,19	0,48	1,09	0,14
5	25	5	65,00	4	1,31	18,35	65	10,19	0,48	1,22	0,11
2	25	5	65,00	1,6	1,20	20,12	65	10,19	0,48	1,41	0,08
1	25	5	65,00	0,8	1,14	21,14	65	10,19	0,48	1,51	0,07
10	25	10	65,00	6	1,38	17,41	65	10,19	0,48	1,11	0,13
8	25	10	65,00	4,8	1,34	17,94	65	10,19	0,48	1,17	0,12
5	25	10	65,00	3	1,27	18,96	65	10,19	0,48	1,28	0,10
2	25	10	65,00	1,2	1,17	20,57	65	10,19	0,48	1,45	0,07

1	25	10	65,00	0,6	1,12	21,50	65	10,19	0,48	1,54	0,06
10	25	15	65,00	4	1,31	18,35	65	10,19	0,48	1,22	0,11
8	25	15	65,00	3,2	1,28	18,82	65	10,19	0,48	1,27	0,10
5	25	15	65,00	2	1,22	19,73	65	10,19	0,48	1,37	0,09
2	25	15	65,00	0,8	1,14	21,14	65	10,19	0,48	1,51	0,07
1	25	15	65,00	0,4	1,10	21,94	65	10,19	0,48	1,58	0,06
10	25	20	65,00	2	1,22	19,73	65	10,19	0,48	1,37	0,09
8	25	20	65,00	1,6	1,20	20,12	65	10,19	0,48	1,41	0,08
5	25	20	65,00	1	1,16	20,84	65	10,19	0,48	1,48	0,07
2	25	20	65,00	0,4	1,10	21,94	65	10,19	0,48	1,58	0,06
1	25	20	65,00	0,2	1,07	22,53	65	10,19	0,48	1,64	0,05

Table 58: Shows the probability of failure for Duplex stainless steel

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28
1	25	0	1	3,9 %	0,24
8	25	5	6,4	25,2 %	0,38
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,27
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,35
5	25	10	3	11,8 %	0,31
2	25	10	1,2	4,7 %	0,25
1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,27

5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,20

Table 59: Duplex Stainless steel Case A- the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	**Average Service Life Of The Pipeline**	**Life Of The Initial Protection Provided To The Pipeline**	**Loss of wall Thickness**	**Percentage of Wall Thickness Loss (%)**	**Probability of Failure**
10	25	0	10	39,4 %	0,44
8	25	0	8	31,5 %	0,41
5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28
1	25	0	1	3,9 %	0,24
10	25	5	8	31,5 %	0,41
8	25	5	6,4	25,2 %	0,38
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,27
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,35

5	25	10	3	11,8 %	0,31
2	25	10	1,2	4,7 %	0,25
1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,27
5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,20

Table 60: Duplex Stainless steel Case B- the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,44
8	25	0	8	31,5 %	0,41

5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28
1	25	0	1	3,9 %	0,24
10	25	5	8	31,5 %	0,41
8	25	5	6,4	25,2 %	0,38
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,27
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,35
5	25	10	3	11,8 %	0,31
2	25	10	1,2	4,7 %	0,25
1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,27
5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,20

Table 61: Duplex Stainless steel Case C- the correlation between the efficiency of inhibitor required and the life of initial protection required

9.3.8 PROBABILITY OF FAILURE FOR SUPER DUPLEX STEEL

The calculation results for the probability of failure for Super Duplex Steel material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	Average service life of the pipeline	Life of the initial protection provided to the pipeline	Specified Minimum Yield Strength (SMYS) (KPSI)	Depth Of Corrosion	Stress Concentration Factor	Probabilistic Burst Pressure Corroded (PBD) (KPsi)	Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)	Deterministic Burst Pressure (PB) (KPsi)	Standard Variance	Safety Index (β)	Probability of Failure
10	25	0	80,00	10	1,50	19,83	116	18,19	0,48	0,18	0,43
8	25	0	80,00	8	1,44	20,55	116	18,19	0,48	0,25	0,40
5	25	0	80,00	5	1,35	21,96	116	18,19	0,48	0,39	0,35
2	25	0	80,00	2	1,22	24,28	116	18,19	0,48	0,60	0,28
1	25	0	80,00	1	1,16	25,65	116	18,19	0,48	0,71	0,24
10	25	5	80,00	8	1,44	20,55	116	18,19	0,48	0,25	0,40
8	25	5	80,00	6,4	1,40	21,24	116	18,19	0,48	0,32	0,37
5	25	5	80,00	4	1,31	22,58	116	18,19	0,48	0,45	0,33
2	25	5	80,00	1,6	1,20	24,76	116	18,19	0,48	0,64	0,26
1	25	5	80,00	0,8	1,14	26,02	116	18,19	0,48	0,74	0,23
10	25	10	80,00	6	1,38	21,43	116	18,19	0,48	0,34	0,37
8	25	10	80,00	4,8	1,34	22,08	116	18,19	0,48	0,40	0,34
5	25	10	80,00	3	1,27	23,33	116	18,19	0,48	0,51	0,30
2	25	10	80,00	1,2	1,17	25,32	116	18,19	0,48	0,68	0,25

1	25	10	80,00	0,6	1,12	26,46	116	18,19	0,48	0,77	0,22
10	25	15	80,00	4	1,31	22,58	116	18,19	0,48	0,45	0,33
8	25	15	80,00	3,2	1,28	23,17	116	18,19	0,48	0,50	0,31
5	25	15	80,00	2	1,22	24,28	116	18,19	0,48	0,60	0,28
2	25	15	80,00	0,8	1,14	26,02	116	18,19	0,48	0,74	0,23
1	25	15	80,00	0,4	1,10	27,00	116	18,19	0,48	0,82	0,21
10	25	20	80,00	2	1,22	24,28	116	18,19	0,48	0,60	0,28
8	25	20	80,00	1,6	1,20	24,76	116	18,19	0,48	0,64	0,26
5	25	20	80,00	1	1,16	25,65	116	18,19	0,48	0,71	0,24
2	25	20	80,00	0,4	1,10	27,00	116	18,19	0,48	0,82	0,21
1	25	20	80,00	0,2	1,07	27,73	116	18,19	0,48	0,87	0,19

Table 62: Shows the probability of failure for Super Duplex Steel

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Super Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	**Average Service Life Of The Pipeline**	**Life Of The Initial Protection Provided To The Pipeline**	**Loss of wall Thickness**	**Percentage of Wall Thickness Loss (%)**	**Probability of Failure**
5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28
1	25	0	1	3,9 %	0,24
8	25	5	6,4	25,2 %	0,37
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,26
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,34
5	25	10	3	11,8 %	0,30
2	25	10	1,2	4,7 %	0,25
1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,26

5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,19

Table 63: Super Duplex Case A - the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Super Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,43
8	25	0	8	31,5 %	0,40
5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28
1	25	0	1	3,9 %	0,24
10	25	5	8	31,5 %	0,40
8	25	5	6,4	25,2 %	0,37
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,26
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,34
5	25	10	3	11,8 %	0,30
2	25	10	1,2	4,7 %	0,25

1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,26
5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,19

Table 64: Super Duplex Case B - the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Super Duplex Steel

Corrosion Rate = 0.04 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	10	39,4 %	0,43
8	25	0	8	31,5 %	0,40
5	25	0	5	19,7 %	0,35
2	25	0	2	7,9 %	0,28

1	25	0	1	3,9 %	0,24
10	25	5	8	31,5 %	0,40
8	25	5	6,4	25,2 %	0,37
5	25	5	4	15,7 %	0,33
2	25	5	1,6	6,3 %	0,26
1	25	5	0,8	3,1 %	0,23
10	25	10	6	23,6 %	0,37
8	25	10	4,8	18,9 %	0,34
5	25	10	3	11,8 %	0,30
2	25	10	1,2	4,7 %	0,25
1	25	10	0,6	2,4 %	0,22
10	25	15	4	15,7 %	0,33
8	25	15	3,2	12,6 %	0,31
5	25	15	2	7,9 %	0,28
2	25	15	0,8	3,1 %	0,23
1	25	15	0,4	1,6 %	0,21
10	25	20	2	7,9 %	0,28
8	25	20	1,6	6,3 %	0,26
5	25	20	1	3,9 %	0,24
2	25	20	0,4	1,6 %	0,21
1	25	20	0,2	0,8 %	0,19

Table 65: Super Duplex Case C - the correlation between the efficiency of inhibitor required and the life of initial protection required

9.3.9 PROBABILITY OF FAILURE FOR TITANIUM

The calculation results for the probability of failure for Titanium material underusing the deterministic and probabilistic models is presented below.

Inhibitor Efficiency	Average service life of the pipeline	Life of the initial protection provided to the pipeline	Specified Minimum Yield Strength (SMYS) (KPSI)	Depth Of Corrosion	Stress Concentration Factor	Probabilistic Burst Pressure Corroded (PBD) (KPsi)	Specified Minimum Tensile Strength of pipeline material (SMTS) (KPsi)	Deterministic Burst Pressure (PB) (KPsi)	Standard Variance	Safety Index (β)	Probability of Failure
10	25	0	25,00	0,75	1,14	8,16	35	5,49	0,48	0,82	0,21
8	25	0	25,00	0,6	1,12	8,27	35	5,49	0,48	0,85	0,20
5	25	0	25,00	0,375	1,10	8,46	35	5,49	0,48	0,89	0,19
2	25	0	25,00	0,15	1,06	8,74	35	5,49	0,48	0,96	0,17
1	25	0	25,00	0,075	1,04	8,89	35	5,49	0,48	1,00	0,16
10	25	5	25,00	0,6	1,12	8,27	35	5,49	0,48	0,85	0,20
8	25	5	25,00	0,48	1,11	8,36	35	5,49	0,48	0,87	0,19
5	25	5	25,00	0,3	1,09	8,54	35	5,49	0,48	0,91	0,18
2	25	5	25,00	0,12	1,05	8,80	35	5,49	0,48	0,98	0,16
1	25	5	25,00	0,06	1,04	8,93	35	5,49	0,48	1,01	0,16
10	25	10	25,00	0,45	1,11	8,39	35	5,49	0,48	0,88	0,19
8	25	10	25,00	0,36	1,09	8,48	35	5,49	0,48	0,90	0,18
5	25	10	25,00	0,225	1,07	8,63	35	5,49	0,48	0,94	0,17
2	25	10	25,00	0,09	1,05	8,86	35	5,49	0,48	0,99	0,16

1	25	10	25,00	0,045	1,03	8,98	35	5,49	0,48	1,02	0,15
10	25	15	25,00	0,3	1,09	8,54	35	5,49	0,48	0,91	0,18
8	25	15	25,00	0,24	1,08	8,61	35	5,49	0,48	0,93	0,18
5	25	15	25,00	0,15	1,06	8,74	35	5,49	0,48	0,96	0,17
2	25	15	25,00	0,06	1,04	8,93	35	5,49	0,48	1,01	0,16
1	25	15	25,00	0,03	1,03	9,03	35	5,49	0,48	1,03	0,15
10	25	20	25,00	0,15	1,06	8,74	35	5,49	0,48	0,96	0,17
8	25	20	25,00	0,12	1,05	8,80	35	5,49	0,48	0,98	0,16
5	25	20	25,00	0,075	1,04	8,89	35	5,49	0,48	1,00	0,16
2	25	20	25,00	0,03	1,03	9,03	35	5,49	0,48	1,03	0,15
1	25	20	25,00	0,015	1,02	9,10	35	5,49	0,48	1,05	0,15

Table 66: Shows the probability of failure for Titanium

Case-A:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	0,75	3,0 %	0,21
8	25	0	0,6	2,4 %	0,20
5	25	0	0,375	1,5 %	0,19
2	25	0	0,15	0,6 %	0,17
1	25	0	0,075	0,3 %	0,16
10	25	5	0,6	2,4 %	0,20
8	25	5	0,48	1,9 %	0,19
5	25	5	0,3	1,2 %	0,18
2	25	5	0,12	0,5 %	0,16
1	25	5	0,06	0,2 %	0,16
10	25	10	0,45	1,8 %	0,19
8	25	10	0,36	1,4 %	0,18
5	25	10	0,225	0,9 %	0,17
2	25	10	0,09	0,4 %	0,16
1	25	10	0,045	0,2 %	0,15
10	25	15	0,3	1,2 %	0,18
8	25	15	0,24	0,9 %	0,18
5	25	15	0,15	0,6 %	0,17
2	25	15	0,06	0,2 %	0,16

1	25	15	0,03	0,1 %	0,15
10	25	20	0,15	0,6 %	0,17
8	25	20	0,12	0,5 %	0,16
5	25	20	0,075	0,3 %	0,16
2	25	20	0,03	0,1 %	0,15
1	25	20	0,015	0,1 %	0,15

Table 67: Titanium Case A - the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-B:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 60% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	0,75	3,0 %	0,21
8	25	0	0,6	2,4 %	0,20
5	25	0	0,375	1,5 %	0,19
2	25	0	0,15	0,6 %	0,17
1	25	0	0,075	0,3 %	0,16
10	25	5	0,6	2,4 %	0,20
8	25	5	0,48	1,9 %	0,19
5	25	5	0,3	1,2 %	0,18
2	25	5	0,12	0,5 %	0,16
1	25	5	0,06	0,2 %	0,16

10	25	10	0,45	1,8 %	0,19
8	25	10	0,36	1,4 %	0,18
5	25	10	0,225	0,9 %	0,17
2	25	10	0,09	0,4 %	0,16
1	25	10	0,045	0,2 %	0,15
10	25	15	0,3	1,2 %	0,18
8	25	15	0,24	0,9 %	0,18
5	25	15	0,15	0,6 %	0,17
2	25	15	0,06	0,2 %	0,16
1	25	15	0,03	0,1 %	0,15
10	25	20	0,15	0,6 %	0,17
8	25	20	0,12	0,5 %	0,16
5	25	20	0,075	0,3 %	0,16
2	25	20	0,03	0,1 %	0,15
1	25	20	0,015	0,1 %	0,15

Table 68: Titanium Case B - the correlation between the efficiency of inhibitor required and the life of initial protection required

Case-C:

The following table describes the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 90% loss of wall thickness of the pipe.

Size of Pipe = 12" or DN 300

Wall Thickness = 25.4mm

Schedule = 120

Material = Titanium

Corrosion Rate = 0.003 mm/yr.

Inhibitor Efficiency	Average Service Life Of The Pipeline	Life Of The Initial Protection Provided To The Pipeline	Loss of wall Thickness	Percentage of Wall Thickness Loss (%)	Probability of Failure
10	25	0	0,75	3,0 %	0,21
8	25	0	0,6	2,4 %	0,20
5	25	0	0,375	1,5 %	0,19
2	25	0	0,15	0,6 %	0,17
1	25	0	0,075	0,3 %	0,16
10	25	5	0,6	2,4 %	0,20
8	25	5	0,48	1,9 %	0,19
5	25	5	0,3	1,2 %	0,18
2	25	5	0,12	0,5 %	0,16
1	25	5	0,06	0,2 %	0,16
10	25	10	0,45	1,8 %	0,19
8	25	10	0,36	1,4 %	0,18
5	25	10	0,225	0,9 %	0,17
2	25	10	0,09	0,4 %	0,16
1	25	10	0,045	0,2 %	0,15
10	25	15	0,3	1,2 %	0,18
8	25	15	0,24	0,9 %	0,18
5	25	15	0,15	0,6 %	0,17
2	25	15	0,06	0,2 %	0,16
1	25	15	0,03	0,1 %	0,15
10	25	20	0,15	0,6 %	0,17
8	25	20	0,12	0,5 %	0,16
5	25	20	0,075	0,3 %	0,16
2	25	20	0,03	0,1 %	0,15
1	25	20	0,015	0,1 %	0,15

Table 69: Titanium Case C - the correlation between the efficiency of inhibitor required and the life of initial protection required

9.4 CARBON STEEL VS CORROSION RESISTANT ALLOYS WRT AVAILABILITY

Carbon Steel Availability

According to the definition adapted for Availability in chapter 8.5, the availability factor of material selection is drawn from the corrosion inhibitor availability perspective. When evaluating corrosivity in flowlines or hydrocarbon systems, M-001 suggests to include the parameters such as amount of CO2, H2S and O2, operating temperature and pressure, amount of organic acids or in other words pH, velocity of the flow, kind of flow regime, metallic ion concentration, biological activity and condensing conditions.

Carbon steel is an acceptable material for the use in flowlines where a nominal corrosion allowance is deemed necessary for dehydration process upsets. Such a scenario recommends corrosion allowance to be limited to 3mm. However, when selecting carbon steel for wet gas circuits, it is recommended to make use of parameters such as corrosion allowance and corrosion allowance with the application of corrosion inhibitors. The idea behind such a selection is that when an appropriate inhibitor is used, the resulting corrosion rate henceforth is kept low irrespective of the natural corrosion rate or in other words uninhibited corrosion rates for the hydrocarbons in the system.

There are significant number of methodologies or packages available practically in the market for corrosion modelling. The type of selection of corrosion modelling is operators choice of selection which are either available commercially in the market or been developed in-house. Examples of in-house developed are Hydrocorr by Shell, Cassandra by British Petroleum. In addition there are some commercially available corrosion modelling packages such as Honeywell/Intercorr Predict 4.0, Multicorp developed by University of Ohio etc (Marsh and The, 2007). Since the objective of the research is to focus more on the material selection characteristics rather than corrosion modelling of hydrocarbons, the national standard adapted in the North Sea in the form of NORSOK Standard M-506 has been adapted. Majority of the packages available are in one way or the other depict their base on the technique and philosophies recommended by DeWaard and Milliams using the nomograph as shown in figure . An example of a model that stands on the work of DeWaard and Milliams is the NORSOK M-506 corrosion model.

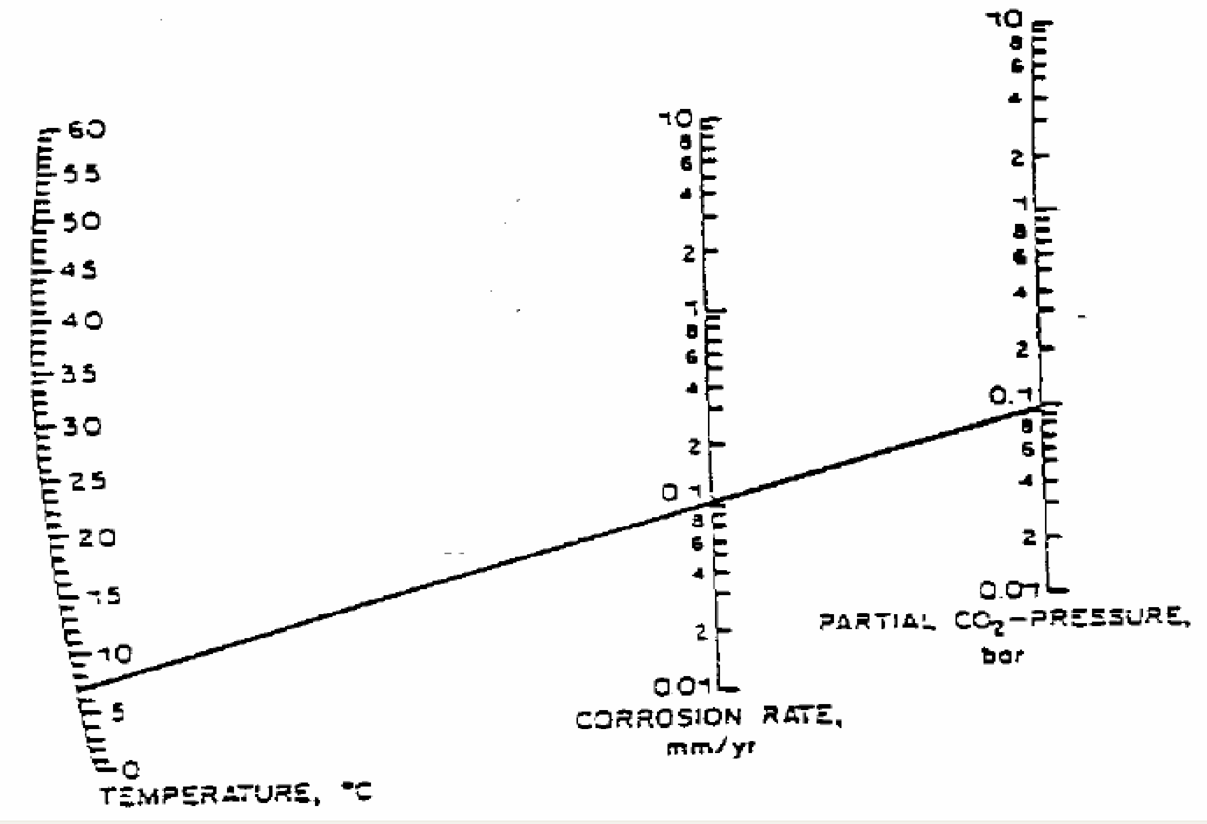


Figure 13: CO_2 Corrosion rate

(Source: http://webwormcpt.blogspot.no/2008/10/quick-estimation-of-co2-corrosion-rate.html)

In order to illustrate the significance of inhibitor availability the researcher adapted the results of the corrosion allowance results of a theoretical pipeline by the work done by Marsh and Teh (2007), with significant input parameters. The corrosion allowance has been evaluated using the Cassandra model used by the operator British Petroleum and NORSOK M-506 model and the results are distributed in the following four cases. With the available experimental results limited to 20 years of design life, the researcher used the conservative extrapolation technique to reach the corrosion allowances for 25 years in order to demonstrate the availability characteristic.

Case 1 :

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO_2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
1A	65 degrees Celsius	1.5	3.4	4.25

Table 70: Carbon steel availability NORSOK M-506 Model, Case 1

Case 2:

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO_2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
2A	100 degrees Celsius	0.4	2.3	4.25

Table 71: Carbon steel availability NORSOK M-506 Model, Case 2

Case 3:

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO_2 = 5 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
3A	100 degrees Celsius	2.3	4.2	5.25

Table 72: Carbon steel availability NORSOK M-506 Model, Case 3

Case 4 :

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
4A	65 degrees Celsius	1.5	1.3	1.625

Table 73: Carbon steel availability NORSOK M-506 Model, Case 4

Case 5:

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
5A	100 degrees Celsius	0.4	2.1	2.625

Table 74: Carbon steel availability NORSOK M-506 Model, Case 5

Case 6:

Model : NORSOK M-506

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1   mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO_2 = 5 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
6A	100 degrees Celsius	2.3	2.5	3.125

Table 75: Carbon steel availability NORSOK M-506 Model, Case 6

Case 7 :

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO_2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
1A	65 degrees Celsius	2.5	4.4	5.5

Table 76: Carbon steel availability BP Cassandra Model, Case 7

Case 8:

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
2A	100 degrees Celsius	4.8	6.7	8.375

Table 77: Carbon steel availability BP Cassandra Model, Case 8

Case 9:

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 95%

Corrosion Rate = 0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 5 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
3A	100 degrees Celsius	10.9	12.8	16

Table 78: Carbon steel availability BP Cassandra Model, Case 9

Case 10 :

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
4A	65 degrees Celsius	2.5	1.5	1.875

Table 79: Carbon steel availability BP Cassandra Model, Case 10

Case 11:

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 1 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
5A	100 degrees Celsius	4.8	2.9	3.625

Table 80: Carbon steel availability BP Cassandra Model, Case 11

Case 12:

Model : BP CASSANDRA

Design life period = 25 Years

Availability Upper limit = 99%

Corrosion Rate = 0.05/0.1 mm/yr.

NaCl = 100000 ppm

Bicarbonate Ions = 500 ppm

Percentage CO2 = 5 % in the gas phase

No pH stabilization as recommended by NORSOK M-001 and Flow effects Ignored

Results:

Model	Temperature	Uninhibited Corrosion Rate (mm/yr.)	Corrosion Allowance (mm)	Extrapolated Corrosion Allowance (mm)
6A	100 degrees Celsius	10.9	4.2	5.25

Table 81: Carbon steel availability BP Cassandra Model, Case 12

According to TR2000, the maximum corrosion allowance for carbon steel grade materials flowline and piping from wellhead to separator is 3mm and for that for corrosion resistant alloys the corrosion allowance is 1mm. While selecting the material for flow lines, M-001, suggests that when the predicted corrosion rates are low enough, the service life corrosion can be accommodated by a practical corrosion allowance. But when the service life corrosion exceeds the maximum corrosion allowance practically possible, then the possibility of reducing corrosion rate to an acceptable level is considered by the application of corrosion inhibition philosophy. The philosophy is based on the use of appropriate inhibitor so that the resulting corrosion rate is practically kept as low as possible despite the fact inevitable natural corrosion in the system. The service life corrosion for the models described above can therefore be calculated as table below.

Model	Service Life	Uninhibited Corrosion Rate (mm/yr)	Uninhibited Service Life Corrosion (mm)
1A	25 Years	1.5	37.5
2A	25 Years	0.4	10
3A	25 Years	2.3	57.5
4A	25 Years	1.5	37.5
5A	25 Years	0.4	10
6A	25 Years	2.3	57.5
7A	25 Years	2.5	62.5
8A	25 Years	4.8	120
9A	25 Years	10.9	272.5
10A	25 Years	2.5	62.5
11A	25 Years	4.8	120
12A	25 Years	10.9	272.5

Table 82: Shows Summarised Uninhibited corrosion rate and service life

The NORSOK standard recommends the use of corrosion rate of the order 0.1mm/yr. for design purposes when there is no field or test data available, the researcher instead put forth a practical approach based on the calculated corrosion allowances for the material used for flowlines in different facilities. The corrosion rate for a service design life of 25 years is therefore calculated as shown in the table below for different materials.

Material	Service Life	Corrosion Allowance (mm)	Corrosion Rate (mm/yr.)	M-001 Recommended Corrosion Rate (mm/yr.)
Carbon Steel	25 Years	3	0.12	0.1
Stainless Steel	25 Years	1	0.04	0.1

6MO	25 Years	1	0.04	0.1
Duplex	25 Years	1	0.04	0.1
Super Duplex	25 Years	1	0.04	0.1
Titanium	25 Years	0	0.003	0.1

Table 83: Shows corrosion rate for various materials for a design life of 25 years

The following table demonstrates the required availability of the corrosion inhibitor or in other words the time the inhibitor is required to be present during system's operation or functioning at the concentration levels that is above or below the required minimum dosage for carbon steel.

Model	M-001 Recommended Corrosion Rate (mm/yr.)	Experimental Uninhibited Corrosion rate	Experimental Corrosion Allowance	Required Corrosion Allowance	Required Inhibitor Availability
1A	0.1	1.5	4.25	3	> 95%
2A	0.1	0.4	4.25	3	> 95%
3A	0.1	2.3	5.25	3	> 95%
4A	0.1	1.5	1.625	3	< 95%
5A	0.1	0.4	2.625	3	< 95%
6A	0.1	2.3	3.125	3	> 95%
7A	0.1	2.5	5.5	3	> 95%
8A	0.1	4.8	8.375	3	> 95%
9A	0.1	10.9	16	3	> 95%
10A	0.1	2.5	1.875	3	< 95%
11A	0.1	4.8	3.625	3	> 95%
12A	0.1	10.9	5.25	3	> 95%

Table 84: Shows the required availability of the corrosion inhibitor for carbon steel

The NORSOK standard suggests the use of inhibitor availability of 90% with a maximum inhibitor availability not exceeding 95%. The aforementioned results of the model NORSOK M-506 and BP's CASSANDRA demonstrate the need for having the inhibitor available for more than 95% in 4 cases with accordance to model M-506 and 5 cases with accordance to model CASSANDRA. This means that a qualified inhibitor is deemed to be present and put in use from day one of the material's operating life and there is a need for a participating corrosion monitoring program and inhibitor injection.

The results henceforth suggest the use of corrosion resistant alloys in majority of the with a maximum inhibitor availability not exceeding 95% in any of the 12 cases for stainless steel grade materials as shown in the table below.

Model	M-001 Recommended Corrosion Rate (mm/yr.)	Experimental Uninhibited Corrosion rate	Experimental Corrosion Allowance	Required Corrosion Allowance	Required Inhibitor Availability
1A	0.1	1.5	4.25	1	< 95%
2A	0.1	0.4	4.25	1	< 95%
3A	0.1	2.3	5.25	1	< 95%
4A	0.1	1.5	1.625	1	< 95%
5A	0.1	0.4	2.625	1	< 95%
6A	0.1	2.3	3.125	1	< 95%
7A	0.1	2.5	5.5	1	< 95%
8A	0.1	4.8	8.375	1	< 95%
9A	0.1	10.9	16	1	< 95%
10A	0.1	2.5	1.875	1	< 95%
11A	0.1	4.8	3.625	1	< 95%
12A	0.1	10.9	5.25	1	< 95%

Table 85: Shows the required availability of the corrosion inhibitor for stainless steel

The results henceforth suggest the use of corrosion resistant alloys in majority of the with a maximum inhibitor availability not exceeding 95% in any of the 12 cases for Duplex, Super duplex and titanium grade materials as shown in the table below.

Model	M-001 Recommended Corrosion Rate (mm/yr.)	Experimental Uninhibited Corrosion rate	Experimental Corrosion Allowance	Required Corrosion Allowance	Required Inhibitor Availability
1A	0.1	1.5	4.25	1	< 95%
2A	0.1	0.4	4.25	1	< 95%
3A	0.1	2.3	5.25	1	< 95%

4A	0.1	1.5	1.625	1	< 95%
5A	0.1	0.4	2.625	1	< 95%
6A	0.1	2.3	3.125	1	< 95%
7A	0.1	2.5	5.5	1	< 95%
8A	0.1	4.8	8.375	1	< 95%
9A	0.1	10.9	16	1	< 95%
10A	0.1	2.5	1.875	1	< 95%
11A	0.1	4.8	3.625	1	< 95%
12A	0.1	10.9	5.25	1	< 95%

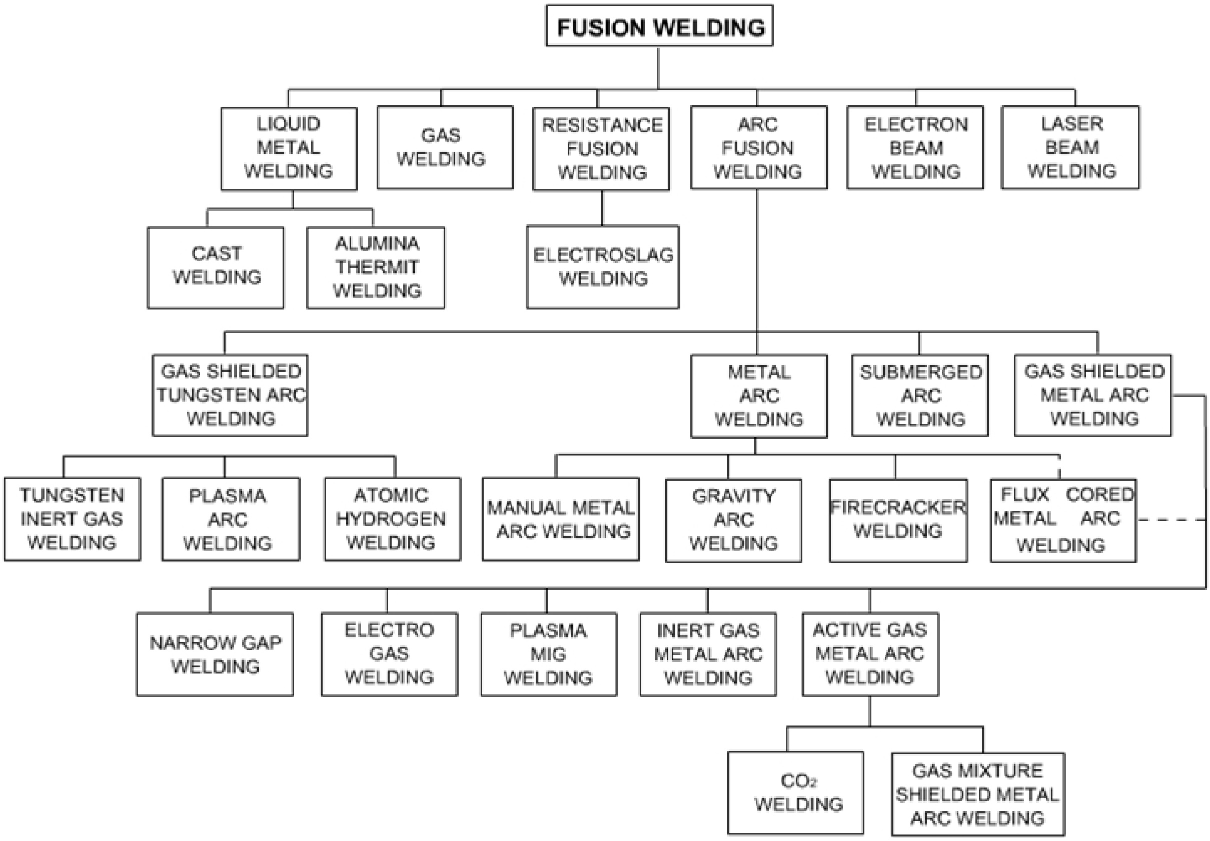
Table 86: Shows the required availability of the corrosion inhibitor for Duplex, super duplex and titanium

9.5 CARBON STEEL VS CORROSION RESISTANT ALLOYS WRT FABRICATION

9.5.1 PIPE FABRICATION PROCESS

The offshore industry in general uses various materials such as carbon steel, stainless steel, Duplex, titanium etc. for fabricating the pipes for flow lines. Due to the diverse characteristics of each material, the standards, techniques and fabrication means change accordingly. The selection of material and therefore the construction methods significantly affects the cost in a project and at the same time governs the key characteristics such as availability, maintainability and reliability. The activities in fabrication can be summarized into welding, pipe spools/fitting handling, testing, pipe supports welded to the pipe spool , marking the spools for identification, storage , handling of the valves etc..

Welding which stands as one of the core activities is mainly used by the offshore industry as a means to join the pipes and fitting cost effectively. Since the objective of this research is to evaluate the materials based on corrosion resistance, importance is therefore given to the critical factors of welding that affect corrosion resistance. Welding generally administers an electric arc as a heat source between the electrode and the two elements or components to be welded. In order to produce a weld the quintessential are the thermal electrons and positive ions. While the thermal electrons are generated from the arc, the electrode forms the source for the positive ions. The combination of electrons and positive ions are thereby converted to kinetic energy by collision thereby producing a weld. Such weld can be classified as shown in figure below.



Flowchart 3: Classification of welding and allied process

(Source: http://sumitshrivastva.blogspot.no/2012/03/manufacturing-process-welding-its.html)

The weld can, depending upon the type of weld can consist of a consumable or a non-consumable electrode. While consumable consist of a metal or an alloy, the non-consumable electrodes consist of either carbon or tungsten. The non-consumable electrodes are employed when there is a need for protection against oxidation through the use of inert gas to shield the weld atmosphere.

It is general practice that the carbon steel material used for the flow lines undergo some of the heat treatment procedures such as annealing, normalizing, autenizing etc. . But because of welding of materials within the carbon steel family, there is an impending probability that hard regions are created. The effect henceforth is the possibility of sulphide stress cracking.

According to RP0472 “Methods and Controls to Prevent In-Service Environmental Cracking of Carbon Steel weldments in Corrosive Petroleum Refining Environments", the carbon steel weldments have to go through the process of softening to resist failure under cracking by limiting the hardness to 200 HBW (Don, Jeff and Keith, 2004). The cracks as a result of welding can be either cold cracks or hot cracks. While hot cracks come into existence during the process of cooling the weld, cold cracks are a result of delayed formation of cracks once the cooling of the weld is complete. The softening process is achieved through controlling the heat affect zone of the weldment joint using post weld heat treatment, the base metal chemistry and keeping a check on the hardness of the heat affected zone during the qualification of the weld procedure.

9.5.2 HOT CRACKS

Hot cracks can primarily occur when there is low affinity of alloying compounds during the initial stages of cooling once the fabrication through welding is complete. Further, hot cracks can also be observed when the strength of the weld between two components is too weak (Girish, 2013). The initiation of hot cracks can start at the throat of the weld and progressively migrates to the length of the weld leading to longitudinal failure of the weld. One of the influencing factors while selecting duplex and super duplex grade materials over austenitic stainless steel material is that the probability of hot cracking is less.

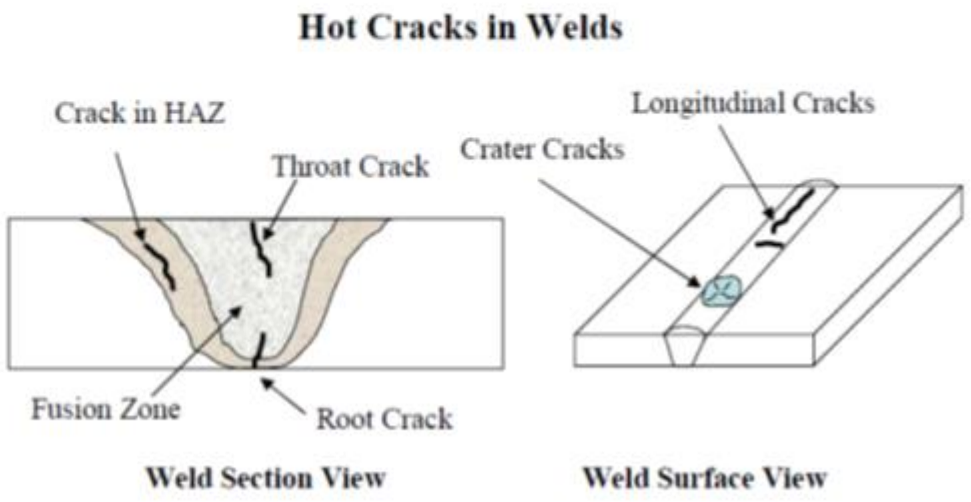


Figure 14: Schematic showing location of typical hot cracks in weld

(Source- Girish, P.K,2013)

It is a general phenomenon that the amount of sulphur in the material dictates the tendency towards hot cracking. Carbon steel materials especially with high sulphur content are more prone to hot cracking and require the need to have substantial amounts of manganese in its composition to mitigate the effects of high sulphur. The stainless steel grade materials, upon the use the fabrication methods such as laser welding as means of creating weldments, the hot cracks come into existence. In addition, any presence of zinc or copper can significantly affect the possibility of hot cracking in stainless steel materials but is usually taken care through the use of meager amount of ferrite during the weld.

The cracking as a result of increased hardness occurs when the percentage of carbon the material is at least 0.25%. So, majority of the materials from the carbon steel grades, including the low carbon steels are significantly hardened during the cooling of the weld. With low percentage of carbon in austenitic, duplex and super duplex steels, the effect as a result of hardening is less as compared to carbon steel. However, the presence of alloys such as manganese, molybdenum and importantly chromium can increase the hardness beyond the recommended levels upon cooling. The amount of heat input therefore should be sufficient enough so as to avoid the precipitation of the alloying elements.

9.5.3 COLD CRACKS

Contrary to hot cracks, cold cracks are a result of failure of the weld once the weld has cooled. Two important reasons can be attributed to the formation of cold cracks. The primary reason for cold cracks is due to the process of diffusion of hydrogen. Diffused hydrogen travels through the weldment and settles down as pockets that create significant pressure for the expansion of the weld defect and thus form a cold crack. It is therefore important that the material is preheated before welding so as to avoid hydrogen diffusion. Another reason for cold cracks is due to the high stress in the weld and is a common phenomenon in pipe where the thickness of the pipe is high. In such situations the cracks propagate in the traverse direction at the heat affected zone of the weld as shown in figure below (Girish, 2013). When using duplex and super duplex grade materials, preheating is not a necessary action to prevent col cracks unless it is used to prevent condensation. However, when creating a weldment between a light component and a heavy component, preheating is administered for duplex and super duplex grade materials.

For austenitic stainless steel, the amount of harness as result of cooling after the weld is very low and hence as a result do not demand the preheat requirements unlike carbon steel grade materials. In addition, such an effort to preheat stainless steel grade materials can be detrimental. The scenario holds good even for post weld heat treatment wherein, the stainless steel grade materials tend to lose the corrosion resistance characteristics once they are post heated to more than 600 degrees. The same is contrary to the needs of carbon steel which requires stress relieving through post weld heat treatment at temperatures between 550 and 650 degrees.

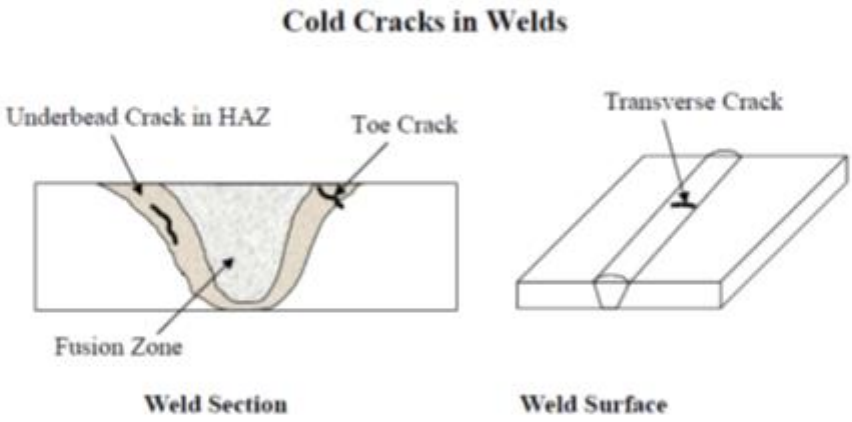


Figure 15: Schematic showing location of typical cold cracks in weld

(Source- Girish, P.K,2013)

9.5.4 FATIGUE CRACKS AND CORROSION CRACKS

The cracks due to fatigue is a result of cracks propagating beyond the heat affected area of the weldment region where the inclemency of residual tensile stresses is generated during the cooling of the weld as shown in following figure. On the other hand, corrosion cracks are a result of high welding temperatures that is required during welding. In general practice fusion welding is used for creating weldments in corrosion resistant alloys. However, the fusion welding demands high temperatures of the order more than 500 degrees. The presence of chromium in corrosion resistant alloys to prevent rust, transform into chromium carbides when they chemically react with the carbon composite at high temperatures. Once the chromium carbides are formed, the material loses the important characteristic of corrosion resistance. The corrosion crack as a result can propagate along the grain structure of the material, thereby affecting the longitudinal cross section of the pipe. Even though post weld treatment offers in itself a solution for corrosion cracks, the use of carbon steel material grade offer excellent solution when it comes to avoiding corrosion cracks as a result of formation of chromium carbides. When it comes to super austenitic stainless steel grade materials, with the use of filler materials with high compounds of molybdenum, the welds offer more retaliation to corrosion than the material itself.

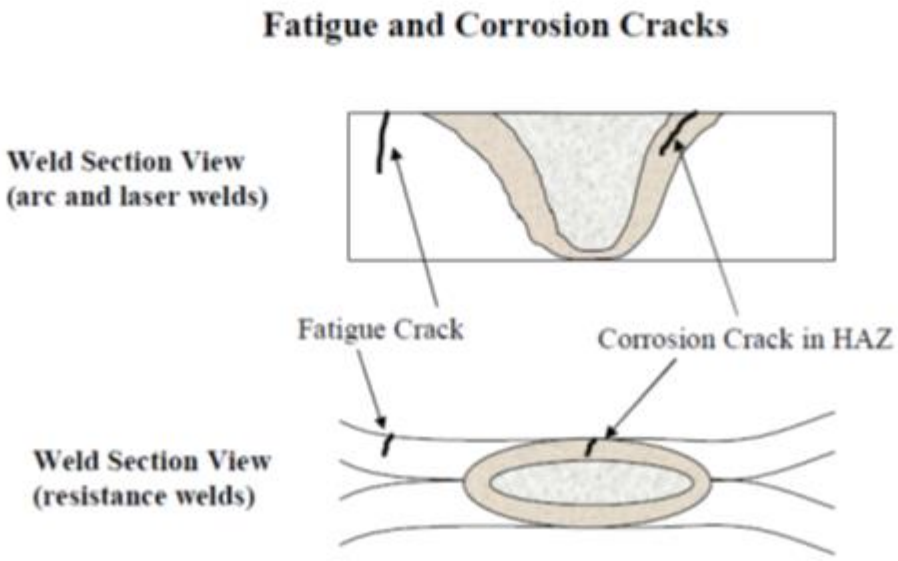


Figure 16: Schematic showing location of fatigue and corrosion crack in and near welds

(Source- Girish, P.K,2013)

9.5.5 SURFACE PREPARATION

In order to create weldments on carbon steel materials, it is steel weld filler material with compositions of manganese and silicon is used to provide the necessary deoxidizing. The use of manganese and silicon allows the weld slag to stay afloat on the surface of the weld. Because of blue or black colored oxides melt at a lower temperature, of the order 1300 degrees, than the temperature of the carbon steel material, the weld is free from formation of scale or iron oxide. The same is not the case with stainless steel grade materials. When creating weldments on stainless steel materials, the surface must be clean or in other words free from any scales or oxides. The presence of chromium in stainless steel material in order to counter corrosion allows the formation of undesired chromium oxide during the weld. This is due the melting temperature of stainless steel being lower than the melting temperature of chromium dioxide. Unlike carbon steel, where the steel weld filler material with compositions of manganese and silicon can be used, the stainless steel material cannot avoid scales formation. Hence, the stainless steel grade materials demand significant amount of cleaning and the weld must be kept clean from formation of black scales. This makes temperature of the weld in stainless steel material to be less than 650 degrees for limiting the scale formation and 816 degrees for avoiding oxidation.

The following tables summarizes the selection of aforementioned characteristics for each of the materials used for oil and gas flow lines according to their pros and cons. Since the characteristics of fabrication discussed earlier do not necessarily form the necessary composites for selecting the material, the researcher also mentioned some additional characteristics that are required to be considered while selecting the materials. The researcher user the information from the supplier SANDVIK Materials Technology and NICKEL Institute for deriving the additional properties of material to be considered during fabrication.

9.5.6 PROS AND CONS OF MATERIALS

316 STAINLESS STEEL

MATERIAL	**WELD CONSUMABLE**						
316L/316 Grade S31603 and S31600	• Enhanced Molybdenum and Chromium • Sulphur Content ≤0.015%						
Material Chemical Composition							
Carbon	Silicon	Manganese	Phosphor	Sulphur	Chromium	Nickel	Molybdenum
≤0.030	≤0.75	≤2.00	≤0.040	≤0.030	16.5	11	2.1

PROS:

- With carbon content less than 0.25%, the material offers good resistance to intergranular corrosion
- Provides good corrosion resistance to organic acids at higher concentrations
- Offers good corrosion resistance to organic acids at high temperatures
- Provides good corrosion resistance to inorganic acids at concentrations higher than the minimum
- Offers good corrosion resistance to higher concentrations of sulphuric acids at low temperatures
- Not prone to attacks from sulphides
- Maintains corrosion resistance characteristic in severe caustic environments
- Welding can be performed without preheating
- Do not require accurate processing in heat treatment

- Post weld heat treatment not necessary
- Excellent for bending with good tolerance to bending radius
- Good machinability
- Because of the low strength, tougher inserts are not required for cutting

CONS:

- Prone to stress corrosion cracking at temperatures greater than 70 degrees when in the proximity of chlorides
- Prone to impurities such as sodium and vanadium during welding
- Lower impact strength of the material after welding
- Requires extensive cleaning to maintain the corrosion resistance properties of weldment and heat affected zone.
- Higher heat Input (1.6 KJ/mm)
- Must use bead Welding technique and requires the need for welding filler material to maintain the corrosion resistance properties of the parent material
- When performing multiple welds the difference between the weld temperatures should not exceed 100 degrees
- When the weldment is under stress, there is a possibility of hot cracking.
- Requires extensive cleaning to maintain avoid hot cracking.
- Limits the weldability to copper alloys as they enhance the failure of the weld due to formation of cracks
- Possess low thermal conductivity
- Requires extensive planning as the weldments are prone to high thermal expansion rates and thereby enhance the property of distortion.
- Possibility of residual stresses and hence requires the need to go through further heat treatment process.

AUSTENITIC STAINLESS STEEL ALLOY 6MO

MATERIAL	WELD CONSUMABLE
6Mo Grade S31254	• Enhanced Molybdenum and Chromium • Sulphur Content ≤0.015%
Material Chemical Composition	

Carbon	Silicon	Manganese	Phosphor	Sulphur	Chromium	Nickel	Molybdenum
≤0.020	≤0.8	≤1.00	≤0.030	≤0.010	20	18	6.1

PROS:

- Welding can be performed without preheating
- Provides good corrosion resistance to organic acids at higher concentrations
- Offers good corrosion resistance to organic acids at high temperatures
- Provides good corrosion resistance to inorganic acids at concentrations higher than the minimum
- Offers good corrosion resistance to higher concentrations of sulphuric acids at low temperatures
- Not prone to attacks from sulphides
- Maintains corrosion resistance characteristic in severe caustic environments
- Post weld heat treatment not necessary
- Do not require accurate processing in heat treatment
- Excellent for bending with good tolerance to bending radius
- Good machinability

CONS:

- Requires extensive cleaning to maintain the corrosion resistance properties of weldment and heat affected zone.
- Higher heat Input (1.5 KJ/mm)
- Lower impact strength of the material after welding
- Must use bead Welding technique and requires the need for welding filler material to maintain the corrosion resistance properties of the parent material
- When performing multiple welds the difference between the weld temperatures should not exceed 100 degrees
- When the weldment is under stress, there is a possibility of hot cracking.
- Requires extensive cleaning to maintain avoid hot cracking.
- Limits the weldability to copper alloys as they enhance the failure of the weld due to formation of cracks
- Possess low thermal conductivity
- Requires extensive planning as the weldments are prone to high thermal expansion rates and thereby enhance the property of distortion.

• Possibility of residual stresses and hence requires the need to go through further heat treatment process. • Because of the high strength, tougher inserts are required for cutting when compared to stainless steel grade materials • Prone to stress corrosion cracking at temperatures greater than 90 degrees when in the proximity of chlorides • Prone to impurities such as sodium and vanadium during welding

SUPER DUPLEX STEEL

MATERIAL	WELD CONSUMABLE						
Super Duplex Grade S32750	• Enhanced Nickel • Sulphur Content ≤0.015%						
Material Chemical Composition							
Carbon	Silicon	Manganese	Phosphor	Sulphur	Chromium	Nickel	Molybdenum
≤0.030	≤0.8	≤1.2	≤0.035	≤0.015	25	7	4

PROS:

- Maintains high proof strength when compared to austenitic and super austenitic steel grades
- With maximum harness requirements of the order 32 HRC, the weldment can be cooled rapidly
- The impact strength before and after welding is more or less the same
- Requires less heat Input and must not exceed a maximum of 1.5 KJ/mm and must be atleast 0.2 KJ/mm
- Does not requires extensive cleaning to maintain avoid hot cracking.
- Welding can be performed without preheating
- Provides good corrosion resistance to organic acids at higher concentrations
- Offers good corrosion resistance to organic acids at high temperatures
- Provides good corrosion resistance to inorganic acids at concentrations higher than the minimum
- When performing multiple welds the difference between the weld temperatures can exceed 150 degrees

- Offers good corrosion resistance to higher concentrations of sulphuric acids at low temperatures
- Do not require extensive planning as the weldments are not prone to high thermal expansion rates and thereby negating the property of distortion.
- Not prone to attacks from sulphides
- Does not mandate the need for welding filler material to maintain the corrosion resistance properties of the parent material
- Maintains corrosion resistance characteristic in severe caustic environments
- Post weld heat treatment not necessary
- Not prone to impurities such as sodium and vanadium during welding
- Does not requires extensive cleaning to maintain the corrosion resistance properties of weldment and heat affected zone.
- Does not induce stress corrosion cracking at temperatures below 300 degrees when in the proximity of chlorides
- Less probability of failure of the weld under stress due to hot cracking
- Good resistance to intergranular corrosion due to the ability to maintain the chemical composition at higher temperatures.
- Possess high thermal conductivity
- Less residual stresses and hence does not require the need to go through further heat treatment process.

CONS:

- Mandates the need for similar filler materials for maintain the corrosion resistance characteristics.
- Obligates similar filler material when required to maintain the high mechanical strength properties
- Limits the weldability to copper alloys as they enhance the failure of the weld due to formation of cracks
- Because of the high strength, tougher inserts are required for cutting when compared to stainless steel grade materials
- Requires high forces for performing the bending activities
- Requires heat treatment after bending in cold conditions to maintain stress corrosion resistance.

• The pipe has to be annealed if subjected to hot bending formation. • High strength of the materials limits the machinability • Inaccurate processing in heat treatment leads to loss of impact toughness • Prone to formation of sigma phase when the cooling rate is not fast enough • Inaccurate composition can lead to sigma phase formation

DUPLEX STEEL

<table>
<tr><th colspan="3">MATERIAL</th><th colspan="5">WELD CONSUMABLE</th></tr>
<tr><td colspan="3">Duplex
Grade
S31803/S32205</td><td colspan="5">• Enhanced Nickel
• Sulphur Content ≤0.015%</td></tr>
<tr><th colspan="8">Material Chemical Composition</th></tr>
<tr><td>Carbon</td><td>Silicon</td><td>Manganese</td><td>Phosphor</td><td>Sulphur</td><td>Chromium</td><td>Nickel</td><td>Molybdenum</td></tr>
<tr><td>≤0.030</td><td>≤1</td><td>≤2</td><td>≤0.03</td><td>≤0.015</td><td>22.5</td><td>5</td><td>3.2</td></tr>
<tr><td colspan="8">PROS:
• Maintains high proof strength when compared to austenitic and super austenitic steel grades
• Good impact strength after welding
• With maximum harness requirements of the order 36 HRC, the weldment can be cooled rapidly
• Requires less heat Input and must not exceed a maximum of 2.5 KJ/mm and must be atleast 0.5 KJ/mm
• Does not requires extensive cleaning to maintain avoid hot cracking.
• Welding can be performed without preheating
• Provides good corrosion resistance to organic acids at higher concentrations
• Offers good corrosion resistance to organic acids at high temperatures
• Provides good corrosion resistance to inorganic acids at concentrations higher than the minimum
• Covered electrodes can be used when welding with carbon steel and stainless steel materials
• When performing multiple welds the difference between the weld temperatures can</td></tr>
</table>

exceed 250 degrees

- Offers good corrosion resistance to higher concentrations of sulphuric acids at low temperatures
- Do not require extensive planning as the weldments are not prone to high thermal expansion rates and thereby negating the property of distortion.
- Not prone to attacks from sulphides
- Does not mandate the need for welding filler material to maintain the corrosion resistance properties of the parent material
- Maintains corrosion resistance characteristic in severe caustic environments
- Post weld heat treatment not necessary
- Not prone to impurities such as sodium and vanadium during welding
- Does not requires extensive cleaning to maintain the corrosion resistance properties of weldment and heat affected zone.
- Does not induce stress corrosion cracking at temperatures below 300 degrees when in the proximity of chlorides
- Less probability of failure of the weld under stress due to hot cracking
- Good resistance to intergranular corrosion due to the ability to maintain the chemical composition at higher temperatures.
- Possess high thermal conductivity
- Less residual stresses and hence does not require the need to go through further heat treatment process.
- Does not requires heat treatment after bending in cold conditions to maintain stress corrosion resistance(up to 25% deformation).

CONS:

- Mandates the need for similar filler materials for maintain the corrosion resistance characteristics.
- Obligates similar filler material when required to maintain the high mechanical strength properties
- Limits the weldability to copper alloys as they enhance the failure of the weld due to formation of cracks
- Because of the high strength, tougher inserts are required for cutting when compared to stainless steel grade materials

- Requires high forces for performing the bending activities
- The pipe has to be annealed if subjected to hot bending formation.
- High strength of the materials limits the machinability
- Inaccurate processing in heat treatment leads to loss of impact toughness
- Prone to formation of sigma phase when the cooling rate is not fast enough
- Inaccurate composition can lead to sigma phase formation

TITANIUM

<table>
<tr><th colspan="2">MATERIAL</th><th colspan="4">WELD CONSUMABLE</th></tr>
<tr><td colspan="2">Titanium
Grade 2</td><td colspan="4">• According to ASME Section II, Part C, SFA 5.16
• Classification ERTi-1 or ERTi-2 or equivalent</td></tr>
<tr><td colspan="6">Material Chemical Composition</td></tr>
<tr><td>Carbon</td><td>Fe</td><td>H</td><td>N</td><td>0</td><td>Ti</td></tr>
<tr><td>≤0.1</td><td>≤0.3</td><td>≤0.015</td><td>≤0.03</td><td>≤0.25</td><td>99.2</td></tr>
<tr><td colspan="6">PROS:
• Lighter in weight and hence handling is easier
• Can resist oxidation effects up to 600 degrees
• With the oxide film distributing evenly on the weldment and the heat affected zone of the parent metal, resistance to corrosion is excellent
• High ductility and hence high formability
• Excellent immunity to weld cracks
• The composition of parent material can be used as filler material
• Welding can be done in any position
• Less prone to weld spatter
• Distortion properties of the parent material is lower than austenitic stainless steels
• Does not require stress relief through post weld heat treatment
• Less coefficient of thermal expansion than stainless steel grade materials
• Greater thermal conductivity when compared to austenitic steels
• Maintains high proof strength when compared to austenitic and super austenitic steel grades
• The impact strength before and after welding is more or less the same
• Welding can be performed without preheating</td></tr>
</table>

- Provides good corrosion resistance to organic acids at higher concentrations
- Offers good corrosion resistance to organic acids at high temperatures
- Provides good corrosion resistance to inorganic acids at concentrations higher than the minimum
- Offers good corrosion resistance to higher concentrations of sulphuric acids at high temperatures
- Not prone to attacks from sulphides
- Does not mandate the need for welding filler material to maintain the corrosion resistance properties of the parent material
- Maintains corrosion resistance characteristic in severe caustic environments
- Post weld heat treatment not necessary
- Does not requires extensive cleaning to maintain the corrosion resistance properties of weldment and heat affected zone.
- Does not induce stress corrosion cracking at temperatures below 300 degrees when in the proximity of chlorides
- Less probability of failure of the weld under stress due to hot cracking
- Good resistance to intergranular corrosion due to the ability to maintain the chemical composition at higher temperatures.
- Less residual stresses and hence does not require the need to go through further heat treatment process.
- High tolerences to pipe bends

CONS:

- Welding requires stringent requirements especially with respect to gas welding
- Possibility of embrittlement when using fusion welding due to contamination with air
- Demands the presence of an inert gas when welding
- Requires specialist orbital welding equipment
- No possibility of greater depth of welds
- Less productivity due to specialization needs
- Requires extensive cleaning to maintain avoid hot cracking
- Demands extensive inspection on welds
- Requires extensive shielding mechanism during welding
- Do not require extensive planning as the weldments are not prone to high thermal

expansion rates and thereby negating the property of distortion. • Requires the surfaces to be dry before welding • Cannot be heat treated in a reducing atmosphere • Prone to impurities such as sodium and vanadium during welding • Possibility of rippling during forming • Cannot be welded with other materials

CARBON STEEL

MATERIAL	WELD CONSUMABLE		
Carbon Steel	• For SMYS $\geq$ 415 MPa, HDM 5 ml/100 g shall be used • Otherwise, HDM 10 ml/100 g shall be used		
Material Chemical Composition			
Carbon	Manganese	Phosphorous	Sulphur
$\leq$0.28	$\leq$1.2	$\leq$0.03	$\leq$0.030
PROS: • Does not demand the need for clean and hence is independent from black scale as iron oxide and scale melt at a much lower temperature than the material. • The steel weld fillers used during welding serve the additional job as deoxidizing agents • High thermal conductivity • Less distortion when compared to stainless steel alloys • Excellent flow of weld fillers • Good weld arc penetration • Less fabrication time • Easy to cold form • Welding can be performed without preheating • Do not require accurate processing in heat treatment • Good machinability • Not prone to impurities such as sodium and vanadium during welding • Maintains good impact strength of the material after welding • Does not require extensive cleaning of the weldment and heat affected zone			

- Possess high thermal conductivity compared to austenitic stainless steel

CONS:

- With carbon content more than 0.25%, the material offers does not offer good resistance to intergranular corrosion
- Requires the material to be grinded to alloy steel grade finish, when required to perform welds between dissimilar materials, especially stainless steel
- Possibility of cracks due to hardening of the weld once the weldment is cooled after welding
- Requires post weld heat treatment to relive stresses
- Becomes less ductile because of heat treatment
- The higher carbon content reduces the weldability
- Carbon percentage lowers the melting point of the material
- Does not provides good corrosion resistance to organic acids at higher concentrations
- Does not offer good corrosion resistance to organic acids at high temperatures
- Does not provide good corrosion resistance to inorganic acids at concentrations higher than the minimum
- Does not provide good corrosion resistance to higher concentrations of sulphuric acids at low temperatures
- Prone to attacks from sulphides
- Does not maintain corrosion resistance characteristic in severe caustic environments
- Because of the high strength, tougher inserts are required for cutting
- Bending with less tolerance to bending radius
- Requires post weld heat treatment
- When the weldment is under stress, there is a possibility of hot cracking

10. DISCUSSION & CONCLUSION

Safety & Environmental impacts:

Safety in operation is always on high priority in oil & gas production. In order to maintain safe environment it is necessary to select the material according to the appropriate reservoir condtions. Selecting less corrosive and highly reliable material reduces number of failures. Improving knowledge about the failures mechanisms increases safety in operation. The fundamentals behind the environmental assisted failure mechanisms are not completely clear. Therefore long term study is needed to get better understanding of these issues.

Inhibitors are often used in pipelines made of carbon steels to control the corrosion. Therefore inhibitors is, however have negative impact from an environmental impact viewpoint. By replacing carbon steels with stainless steels the contamination component is neglected.

LCC:

The essential concepts of LCC methodology for performing the calculations are discussed earlier in this paper. This analysis is done to compare the LCC between carbon steel and five corrosion resistant alloy namely 316 SSTL, 6Mo SSTL, 22 Cr Duplex SSTL, 25 Cr Duplex SSTL and Titanium.

The alternatives having the identical life span can be compared from an engineering economy viewpoint just by comparing the magnitude of the present worth. If the alternatives have different life spans, then the present worth needs to be converted into annualized cost to compare. Therefore best alternative can be selected from the one having lowest annualized cost. Maximum Life span of 25 years are considered for these alternatives.

The LCC results shows that 316 stainless steel is economical for 25 years life span. However there is approximately one million cost difference between 316 sstl, 22 cr duplex sstl and 25 Cr duplex sstl. From these three 25 Cr duplex have better corrosion resistence properties compared to other two materials. Titanium and 6Mo stainless steel comes with higher life cycle cost. They have excellent corrosion resistance properties are uneconomical for lengthy flowlines. Carbon steel with inhibitor is most economical if the service life is 5 years. After 5 years the carbon steel cost gradually increases due to high operation and maintenance cost.

There is a prediction that carbon steel will generally have lowest life cycle cost so its been considered as base case for selecting material for flowlines. It should be noted that when selecting an alternate option it should not be limited only to LCC as driving factor, For making final decision there are also other factors which each choice should also be considered separately.

When implemented correctly, LCC is a powerful tool to show that higher costs at initial stages for corrosion resistant alloys rather than evidently lesser cost, in which the CRA outcomes with considerable savings in operation, maintenance and repair costs in the future.

Reliability:

Following the deterioration of steel structures in offshore production platforms, production flowlines degenerate with time. With degradation of material in the form of corrosion, operators throughout the world operate with a challenge to accommodate the risks associated with aged flowlines. The challenges escalate to extreme risks due to the destructive characteristics of effects of corrosion. The research evaluated reliability as one of the key contributing factors that can be used as a criteria when it comes to material selection of flowlines. Some operators currently pursue carbon steel material for flow lines despite the need for its use comes with the efficiency of the maintenance program. Such a program involves in the application of corrosion inhibitors. The current practices in the industry demands the use of corrosion inhibitors on all carbon steel materials in order to satisfy the safety requirements and ensuring that the facility is in operation without any down time. However, the solution offered as a mitigating mechanism for countering the degradation of carbon steel material through corrosion, translates into a new challenge in the form of administering the maintenance program.

The industry today is posed with an inherent challenge to define and implement a maintenance model or system that is optimized for the measurement and implementation of mitigating mechanisms. The evolution of corrosion resistant alloys has significantly downplayed the need for such an evaluation. However, with rapidly increasing production and operating costs, and with significant developments in branch of reliability engineering, developing the limit state functions has helped operators consolidate some of the practical experiences and probabilistic theories. For developing and optimizing such a maintenance program, it is important that the probability of failure of the material is evaluated using either theoretical simulations or probabilistic simulations. In this research, the researcher made an attempt to understand the significant effects of corrosion using both the probabilistic as well as the deterministic models. By doing so, the researcher, performed the reliability analysis of the materials and quantified the touchstones that determine the failure of the flowlines. The results of touchstones such as strength and force calculated and quantified in chapter 9.

The research has mapped the results of the calculated corrosion rates from using the Cassandra model used by the operator British Petroleum and NORSOK M-506 model with efficiency of the inhibitors to calculate the percentage loss of thickness of pipeline due to corrosion. Based on the results, the research found that to maintain less than 30% of the wall thickness loss due to corrosion, the carbon steel material requires the inhibitor efficiency to be in the range high to very high with the life of initial protection provided to the pipeline in the range of 10 to 20 years. Similarly, the research found that to maintain less than 90% but greater than 30% of the wall thickness loss due to corrosion, the carbon steel material requires the inhibitor efficiency to be in the range very low to high with the life of initial protection provided to the pipeline in the range of 0 to 25 years. For stainless steel, duplex and super duplex grade materials, based on the results, the research found that to maintain less than 30% of the wall thickness loss due to a corrosion rate of 0.04 mm/yr., the materials requires the inhibitor efficiency to be in the range low to very low with the life of initial protection provided to the pipeline in the range of 15 to 20 years. To maintain less than 90% but greater than 30% of the wall thickness loss due to corrosion, the stainless steel, duplex and super duplex grade materials require the inhibitor efficiency to be in the range low to moderate with the life of initial protection provided to the pipeline in the range of 10 to 20 years. For titanium grade materials, based on the results, the research found that to maintain less than 30% of the wall thickness loss due to a corrosion rate of 0.003 mm/yr., the materials requires the inhibitor efficiency to be in the range low with the life of initial protection provided to the pipeline in the range of 20 to 25 years. To maintain less than 90% but greater than 30% of the wall thickness loss due to corrosion, the titanium grade materials require the inhibitor efficiency to be of the range low to very low with the life of initial protection provided to the pipeline in the range of 20 to 25 years.

In order to calculate the safety index and thereafter the probability of failure of the material exposed to corrosion, both deterministic as well as probabilistic has been adapted in this research. The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the carbon steel grade materials with SMYS = 42000 Psi and SMTS = 52000 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the carbon steel pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the carbon steel flowlines translate into a probability of failure of the order 48% with a safety index of 0.05.

Even with very high efficiency of the inhibitor, the probability of failure of the carbon steel material is calculated and found to be 20% with a safety index 0.84. The research also made an important evaluation with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the carbon steel material is in the range 14 % to 25%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the carbon steel material is in the range 29% to 36%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the carbon steel material is in the range 39% to 40%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection of the flowline.

The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the stainless steel grade materials with SMYS = 29732 Psi and SMTS = 74694 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the stainless steel pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the stainless steel flowlines translate into a probability of failure of the order 83% with a safety index of -0.96. With very high efficiency of the inhibitor, the probability of failure of the stainless steel material is calculated and found to be 67% with a safety index -0.43. The research also evaluated stainless steel grade materials with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the stainless steel material is in the range 60% to 77%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the stainless steel material is in the range 81% to 83%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the stainless steel material is in the range 81% to 83%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 15 years of the life of initial protection to the pipeline.

The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the 6Mo grade materials with SMYS = 55000 Psi and SMTS = 107000 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the 6Mo pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the 6Mo flowlines translate into a probability of failure of the order 67% with a safety index of -0.43. With very high efficiency of the inhibitor, the probability of failure of the 6Mo material is calculated and found to be 46% with a safety index 0.1. The research also evaluated 6Mo grade materials with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the 6Mo material is in the range 40% to 59%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the 6Mo material is in the range 64% to 67%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the 6Mo material is in the range 64% to 67%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline.

The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the Duplex grade materials with SMYS = 65000 Psi and SMTS = 95000 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the Duplex pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the Duplex flowlines translate into a probability of failure of the order 17% with a safety index of 0.95. With very high efficiency of the inhibitor, the probability of failure of the Duplex material is calculated and found to be 7% with a safety index 1.48. The research also evaluated Duplex grade materials with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the Duplex material is in the range 20% to 38%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Duplex material is less than 43%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Duplex material is less than 43%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline.

The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the Super Duplex grade materials with SMYS = 80000 Psi and SMTS = 116000 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the Super Duplex pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the Super Duplex flowlines translate into a probability of failure of the order 43% with a safety index of 0.18. With very high efficiency of the inhibitor, the probability of failure of the Super Duplex material is calculated and found to be 24% with a safety index 0.71. The research also evaluated Super Duplex grade materials with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the Super Duplex material is less than

35%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Super Duplex material is less than 35%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Super Duplex material is less than 35%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline.

The results of probabilistic and deterministic models suggest and reiterate that the probability of failure for the Titanium grade materials with SMYS = 25000 Psi and SMTS = 35000 Psi, increases proportionately with decrease in efficiency of the inhibitor and the life of initial protection provided to the Titanium pipeline. The results suggest that a very low efficiency of inhibitor, administered from the beginning of the life of the Titanium flowlines translate into a probability of failure of the order 21% with a safety index of 0.82. With very high efficiency of the inhibitor, the probability of failure of the Titanium material is calculated and found to be 16% with a safety index 1. The research also evaluated Titanium grade materials with respect to the correlation between the efficiency of inhibitor required and the life of initial protection required to be provided to the pipe in order to maintain less than 30% loss of wall thickness of the pipe. The results of the evaluation suggest that the probability of failure of the Titanium material is 21%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. Similarly for maintaining the wall thickness of the pipe in the range 30% to 60 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Titanium material is 21%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline. For maintaining the wall thickness of the pipe in the range 60% to 90 % of initial wall thickness, the results of the evaluation suggest that the probability of failure of the Titanium material is 21%, for inhibitor efficiency falling in the range very low to very high administered during 0 to 20 years of the life of initial protection to the pipeline.

Availability:

With significant developments in the offshore oil and gas industry sector, the management of asset availability and asset management offers a series of challenges to the operators. The challenges henceforth translated into a need for implementing strategies and techniques for satisfying the maintenance protocols for the system to be up and running. As recommended by NORSOK standard M-001, the researcher, in this research, deviated from the availability perspective with respect to spare parts management, complexities in inventory management, economics of inventory, availability of asset management personnel, mismatch between actual demand, purchasing period, stock piling of unnecessary inventory parts etc. and focused on the maintenance management philosophies. The objective of the deviation was to ensure that the asset is utilized to its design life capacity and spend economically on the asset's maintenance requirements. The researcher therefore evaluated availability characteristic of the flowlines materials with respect to the asset management principles rather than the supply chain perspective. By doing so, the researcher latently ensured that the evaluation meets the asset management principles such as low down time, reduce inspection requirements, foresee risks associated with unexpected events and more importantly create a conducive operating environment for zero accidents through maintaining the technical integrity of the flowlines.

Under the heading of corrosion, the researcher evaluated the selection of material from the availability perspective and the results are presented in chapter 9. As discussed in chapter 9. The availability of the material is drawn parallels to the availability of corrosion inhibitor or in other words the time the inhibitor should be made available in order to ensure the system is up and maintain its technical integrity for its designed life. The research adapted the percentage availability formula provided by NORSOK standard M-001 considering the parameters of the operating characteristics such as CO2, H2S and O2, operating temperature and pressure, amount of organic acids or in other words pH, velocity of the flow, kind of flow regime, metallic ion concentration, biological activity and condensing conditions. The quantifiable corrosivity characteristics such as uninhibited corrosion rate and corrosion allowance has been adapted from the results of the two models used this this research namely, NORSOK M-506 and British Petroleum Cassandra for the aforementioned parameters.

Depending upon the operating characteristics, the experimental results of the model NORSOK M-506 and British Petroleum Cassandra are presented in chapter 9. The results suggest that for a 95% availability of the corrosion inhibitor, for a temperature 65 degrees, the experimental corrosion allowance is 4.25 for NORSOK M-506 model and 5.5 for BP

Cassandra model and for 100 degrees the experimental corrosion allowance is in the range 4.25 to 5.25 for NORSOK M-506 model and 8.3 to 16 for BP Cassandra model . Similarly for a 99% availability of the corrosion inhibitor, for a temperature 65 degrees, the experimental corrosion allowance is 1.6 for NORSOK M-506 model and 1.8 for BP Cassandra model and for 100 degrees the experimental corrosion allowance is in the range 2.6 to 3.1 for NORSOK M-506 model and 3.56 to 5.25 for BP Cassandra model . The uninhibited service life corrosion has been calculated by the researcher according to the recommendation of NORSOK M-001 to accommodate the possibility of service life corrosion when the predicted corrosion rates are low. Since the service life corrosion exceeds the maximum corrosion allowance practically possible, the possibility of reducing corrosion rate to an acceptable level is considered by the application of corrosion inhibition philosophy and hence requires the use of appropriate inhibitor so that the resulting corrosion rate is practically kept as low as possible despite the fact inevitable natural corrosion in the system.

The results of the required availability of corrosion inhibitor at the concentration levels that are above or below the required minimum dosage for carbon steel are presented in chapter 9. The results suggest that in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (3mm) and have a corrosion inhibitor availability less than 95%, the required operating characteristics have to be

- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA

The results also suggest that in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (3mm) and have a corrosion inhibitor availability greater than 95%, the required operating characteristics have to be

- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model

- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model

The results of the required availability of corrosion inhibitor at the concentration levels that are above or below the required minimum dosage for stainless steel and 6Mo grade materials are presented in chapter 9. The results suggest that in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (1mm) and have a corrosion inhibitor availability less than 95%, the required operating characteristics have to be

- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model

- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model

The results suggest that for stainless steel and 6Mo grade materials, in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (1mm), the corrosion inhibitor availability is always less than 95%.

For Duplex, super duplex and titanium grade materials, the results of the required availability of corrosion inhibitor at the concentration levels that are above or below the required minimum dosage are presented in chapter 9. The results suggest that in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (1mm) and have a corrosion inhibitor availability less than 95%, the required operating characteristics have to be

- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for NORSOK M-506 model
- A temperature less than 100 degrees with 5 % Co2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 65 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % Co2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model

- A temperature less than 100 degrees with 5 % CO_2 in the gas phase and a corrosion rate 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 65 degrees with 1 % CO_2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 1 % CO_2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model
- A temperature less than 100 degrees with 5 % CO_2 in the gas phase and a corrosion rate 0.05 to 0.1mm/yr. for BP CASSANDRA model

The results suggest that for duplex, super duplex and titanium grade materials, in order to maintain the required corrosion allowance for a design life of 25 years recommended by NORSOK M-001 (1mm), the corrosion inhibitor availability is always less than 95%.

Fabrication:

As discussed in chapter 9, from the fabrication perspective, the corrosion characteristics of materials used for flowlines depend on the material itself, type of filler material used, the kind of welding procedure adopted and the requirement of post weld heat treatment. In addition the researcher also extended the study of fabrication of materials to required heat treatment, preheating requirement, hot forming and cold forming. The researcher evaluated the materials for all the fabrication characteristics and the results are presented in chapter 9.

The diverse characteristics of each material govern the fabrication standards and techniques to be implemented. While carbon steel material provide great flexibility when it comes to preheating requirements, thermal conductivity, cleanliness requirements, great flow characteristics of fillers and good machinability, the high percentage of sulfur in its composition makes it more prone to hot cracking. In order to counter the effects of sulphur carbon steel requires manganese in its composition to mitigate failure due to hot cracking. The stainless steel grade materials are also prone to hot cracking with the presence of zinc or copper and when weldments are created using laser welding. The duplex and super duplex grade materials offer significant benefits compared to austenitic stainless steel material grades and carbon steel material grades as the probability of hot cracking is less.

While selecting carbon steel, the effects of hardening during cooling of the weld due to high percentage of carbon has to be considered. With low percentage of carbon in austenitic,

duplex and super duplex steels, the effect as a result of hardening is less as compared to carbon steel. When evaluating carbon steel with respect to failure due to cold cracking, the material offers an advantage in comparison to stainless steel grade materials. Even though preheating offers a solution to mitigate the failure associated to stainless steel, it adds up the cost and requirement itself. However for austenitic stainless steel, the amount of hardness as a result of cooling after the weld is very low and hence as a result do not demand the preheat requirements unlike carbon steel grade materials. For duplex and super duplex grade materials, preheating is not a necessary action to prevent cold cracks unless it is used to prevent condensation. However, when creating a weldment between a light component and a heavy component, preheating is administered for duplex and super duplex grade materials.
In addition, such an effort to preheat stainless steel grade materials can be detrimental.

The presence of chromium in corrosion resistant alloys to prevent rust, upon chemically reacting with carbon lose the important characteristic of corrosion resistance. The corrosion crack as a result can propagate along the grain structure of the material, thereby affecting the longitudinal cross section of the pipe. Even though post weld treatment offers in itself a solution for corrosion cracks, the use of carbon steel material grade offer excellent solution when it comes to avoiding corrosion cracks as a result of formation of chromium carbides. When it comes to super austenitic stainless steel grade materials, with the use of filler materials with high compounds of molybdenum, the welds offer more retaliation to corrosion than the material itself.
When creating weldments on stainless steel materials, the surface must be clean or in other words free from any scales or oxides. The presence of chromium in stainless steel material, duplex and super duplex materials in order to counter corrosion allows the formation of undesired chromium oxide during the weld. Unlike carbon steel, where the steel weld filler material with compositions of manganese and silicon can be used, the stainless steel material cannot avoid scales formation. Hence, the stainless steel grade materials demand significant amount of cleaning and the weld must be kept clean from formation of black scales. However, duplex and super duplex materials do not necessarily demand the need for surface preparation to mitigate the failure of weldments. However, both duplex and super duplex materials are significantly affected by the insufficient post weld cleaning when compared to stainless steel grade materials leading to the phenomenon of pitting.

Even though the materials under discussion project some significant differences when it comes to their evaluation with respect to welding, preheating, surface preparation, post weld heat treatment etc., the application of suitable techniques and standards can essentially hold the corrosion resistance properties upon fabrication. In addition, the not so favorable need of cost for welding dissimilar materials especially, ascertaining that the materials under weld are subjected to lower stresses by regulating the coefficient of expansion of each material has to be evaluated. However, the resultant costs, facilities, affinity to different materials, required personnel expertise becomes the fourth dimension under which the materials have to be evaluated for taking the holistic analysis of fabrication characteristics.

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12. ABBREVIATIONS

A	-	Annualized Cost
CRA	-	Corrosion Resistant Alloy.
CSCC	-	Chloride induced stress corrosion cracking.
GRP	-	Glass fibre Reinforced Plastic
LCC	-	Life Cycle Cost.
NACE	-	NACE International.
PRE	-	Pitting Resistance Equivalent.
PW	-	Present Worth
SCC	-	Sulphide stress cracking.
SMYS	-	Specified Minimum Yield Strength.
SSTL	-	Stainless Steel
UNS	-	Unified Numbering System
ZRA	-	Zero resistance Ammetry