Corrosion Control, Prevention and Mitigation in Oil & Gas Industry

T. Nagalakshmi, A. Sivasakthi

Abstract: ***The impact of corrosion within the refining industry ends up in the failure of components. This failure leads to closing down the plant to scrub the corroded components. Additionally, corrosion normally causes serious environmental issues, namely spills and releases. A vital resource for all those that are concerned within the corrosion management of oil and gas infrastructure, corrosion management within the oil and gas industry provides engineers and designers with the tools and strategies to plan and implement comprehensive corrosion-management programs for oil and gas infrastructures. Control of corrosion is important for continuous production and evading the well control losses. Materials to be used in down hole have to meet certain characteristics to avoid corrosion and provide additional mechanical strenght. It is potential to determine a logical series of steps for material choice, incorporating analysis of the surroundings, corrosion rate calculations, and final material choice based on established limits. Several developments have taken place in refinement the calculation of CO_2 corrosion rates. Moreover, the definition of bitter examination has been reviewed and a way wider evaluation of the relevance of varied established and new materials for various service conditions has been created.***

Keywords: Corrosion, Corrosion Rates, Corrosion Resistance Environmental Issues, Plant Failure and Refining.

I. INTRODUCTION

Corrosion of materials could be a major challenge to maintaining the integrity of equipment within the industry. Mobile and static mechanical facilities like pipelines, vessels, tanks, compressors, turbines, and then forth are intermittently subjected to degradation and failure because of corrosion. The impact of corrosion within the oil and gas industry considerably contributes to the unproductive time (NPT) of 20–30% lost from exploration to production [3].

II. CORROSION PREVENTION

Unprotected pipelines corrode, in spite of wherever the pipeline is. If it's buried underground, higher than ground or in sea water, it's progressing to corrosion.

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***** Correspondence Author

Dr. T. Nagalakshmi*,Professor, Department of Petroleum Engineering, Academy of Maritime Education and Training (AMET), Chennai. Email: nagalakshmi.t@ametuniv.ac.in

A. Sivasakthi, Assistant Professor, Department of Petroleum Engineering, Vels Institute of Science, Technology and Advanced Studies (VISTAS), Chennai. Email: asivasakthi.a@gmail.com

About 60% of nation's transmission lines approach their lifespan of a half century, many industries dealing a lot about pipeline failures. While not implementing safety measures and having corrosion management program, corrosion makes transporting dangerous material unsafe [8]. Here are a number of the ways NACE (National Association of Corrosion Engineers) recommends as a part of an effective corrosion management program to safeguard oil and gas pipelines. Those corrosion preventive methods are as follows,

A. Cathodic protection
B. Coatings and linings
C. Corrosion Inhibitors
D. Pipeline material

A. Cathodic Protection

Cathodic protection is a technique to manage corrosion by employing a direct electrical current that neutralizes external corrosion generally related to metal pipe. It is typically used once a pipeline is buried underground or in water. While executed on a new pipeline, cathodic protection will forestall corrosion from the beginning. On associate older pipeline, cathodic protection will impede existing corrosion of the pipeline. Tubing protected by cathode is shown in fig. 1.

Fig. 1.Cathode Protected Tubing

B. Coatings and Linings

These are applied to pipelines whether or not higher than or below ground and sometimes are employed in combination with cathodic protection. Another application that is presently obtaining some attention is that the use of fiber-reinforced polymers to strengthen and repair pipelines. The metal strength with and without coating is shown in fig. 2.

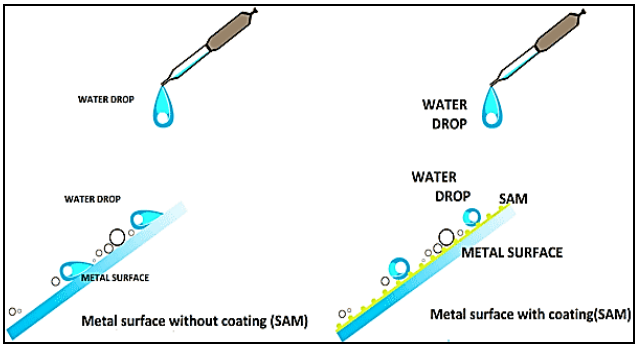

Fig. 2.Coatings at Metal Surface

C. Corrosion Inhibitors

Corrosion inhibitors are chemical substances that once applied to the pipeline of upstream can constrain effect of corrosion in carbon. The most frequently used corrosion inhibitor is low-alloy steels which is found to be economical compared to other alloys.

D. Pipeline Material

Pipeline material also has considerably effect on pipeline corrosion. Some materials have the ability to enhance the lifespan of the pipeline namely PVC, stainless steel and some special alloys whereas some materials will increase the corrosion rate in pipeline such as steel or steel concrete. Therefore the piping material with their roughness vary is shown in fig. 3.

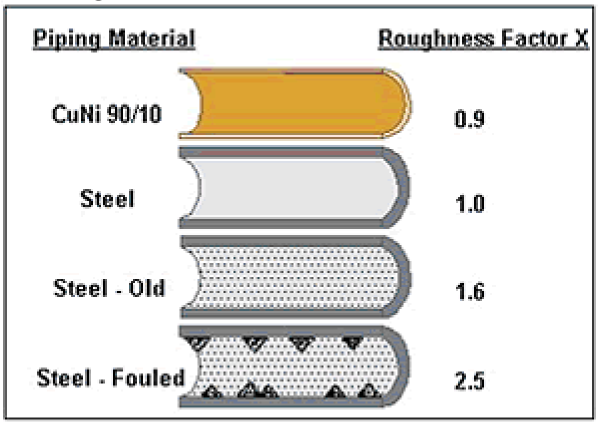

Fig. 3.Selection of Piping Materials

III. CORROSION CONTROL METHODS

There are many ways to control the corrosion occurrence in tubing and they are classified as given below.

A. Carbon Steel Corrosion Inhibition
B. Plastic Coating Inside Tubing
C. Fiber Reinforced Plastic (FRP)
D. Solid Corrosion Resistance Alloys
E. CRA Cladding or Lining

A. Carbon Steel Corrosion Inhibition

Carbon steel corrosion inhibition is successful and presently utilized in many of the oil and gas industries. There are some factors with affect the corrosion inhibition namely the sick wells, oil wells with low temperature and low in water content. Mainly two approaches were implemented in injecting inhibitor into a well [6].

One major difficult related to customary inhibitors is that the condensation will not take place on the pipeline until in the tubing string and temperature is decreasing areas. The most challenging problem of customary inhibitor was overcome by Shell, when they noticed the pipeline failure of P105 implemented in the high temperature wells. Whenever the pipeline corrosion inhibitor is selected for high temperature and high pressure wells, a special attention should be given which is shown in fig. 4.

At present, inhibitors of organic based are not recommended for high temperature greater than 150 ˚C, however analyzing in various depth for a particular operation conditions might permit the use of the inhibitor up to 170 ˚C [7]. Inhibitors can also be used for batch treatment; however they are not effective at high temperatures. Corrosion management proposed that the inhibitors are not suitable for hostile wells due to the following reason given below:

a) The records and documentation of HP/HT wells is weak in future protection; inhibitors ought to a minimum of lengthen the pipeline life expectancy to the amount concerning work overs; whereas in case of HP/HT wells conditions, the effect of inhibitors is still doubtful.
b) The production operations from HP/HT well involves a high operating cost namely the field operation cost throughout the field life time, injection of inhibitors and frequent work overs operations compared to ordinary oil and gas wells.
c) The occurrence of stress cracking in pipelines due to sulphide predominance should be treated with special consideration while selecting the corrosion inhibitors.

Inhibitor	Control Unit	Typical Dosage (ppm)	Normalized Use Cost	Green Status
Molybdate	Mo	10	100	Fair
Zinc	Zn	2	4	Fair
Tin	Sn	2	24	Good
Orthophosphate	PO_4	5	14	Good
Polyphosphate	TKPP	3	4	Good
Polyaminophosphate	PAP	15	30	Good
Hydroxyphosphate Acid	HPA	15	33	Good
Phosphonocarboxylic Acid	PCM	15	50	Good
Aspartic Acid Polymer	AAP	15	23	Excellent
Coffee Extract	Product	-	-	Excellent
Phosphate/Zinc	PO_4 / Zn	5 / 2	17	Fair
Phosphate/Polyphosphate	PO_4 / TKPP	5 / 3	18	Good

Fig. 4.Corrosion Inhibitors in Carbon Steel

B. Plastic Coating Inside Tubing

Plastic coating in pipes has implemented in wide range of applications and exceptional operating conditions. The program of plastic coating inside tubing was started, when the test coated tubing last for several months during batch inhibition without inhibitor injection. The batch inhibition of tubing was very useful during the production operations compared to inhibitor injection. Plastic coating inside the pipes is shown in fig. 5. These are used in Louisiana deep HP gas wells with bottom hole pressure (BHP) about 17000 lb in^{-2} and bottom hole temperature (BHT) around 180 ˚C in shut in conditions along with excessive quantity of H_2S and CO_2 [5].

Plastic coating inside pipelines is not recommended for aggressive wells due to the following difficulties given below:

a) There is a possibility of localized corrosion during the process plastic coating inside tubing.
b) Plastic coating namely phenolic coating will act against pipeline corrosion till 200 ˚C temperature.
c) The plastic type of coating needs to be carefully coated due to some critical conditions such as delamination if the coating is very thick or quick depressurization and localized corrosion if the coating is very thin.
d) Intrusion of gas diffusion in high pressure condition through the coating will leads to corrosion of steel and results in blister damage.
e) Data provided by the corrosion management concerning the corrosion prevention by coating has been inadequate.
f) There is a possibility of damaging the coating during inspection using wire line and caliper analyses.
g) The coated tubing has to be stimulated and cleaned with fluids in order to continue smooth flow but the coated pipe is less resistance to chemicals.

Fig. 5.Internal Plastic Coated Tubing (Courtesy: www.rigzone.com)

C. Fiber Reinforced Plastic

USA has several wells completed with fiber glass tubing. Tubing material coated with fiberglass has good corrosion resistance. Many pipeline applications with inner pressure less than 1000 lb utilities fiber coated tubing. When the fiber coated tubing is subjected to high temperature, they tends to creep and results in pipeline failure. A typical FRP is shown in the fig. 6.

A few shallow well was tested with coated casings/liners but there was an issue of corrosion among resin and H_2S. There is a rise in usage of glass reinforced epoxy lined low alloy steel tubing due to its wide range of pressure limit but this type is unsuitable for HP/HT wells as it has low temperature limits [2].

The use of fiberglass tubular in hostile environments appears is restricted and the selection is not advised because:

a) Typical application is at a low level corrosion means in low temperature below 120 ˚C and low pressure less than 50001b in^{-2} wells.
b) Corrosion resistance coating in some areas seems to be difficult namely near joints, links, certification and compatibility with different components.

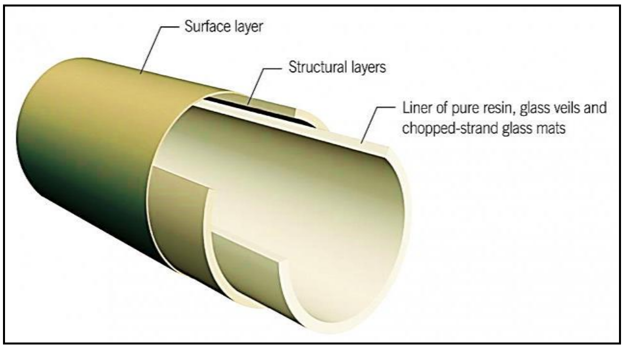

Fig. 6.Fiber Reinforced Plastic

D. Solid Corrosion Resistant Alloys (CRA)

Frequently utilized solid corrosion resistance alloy is stainless steel containing 13Cr. The other alloys that influence corrosion resistance is duplex stainless steels and alloy namely C276, G3, 28 and 825. The corrosion engineering will select the effective corrosion resistance alloy by analyzing their environmental conditions and cost effectiveness [1]. Environmental conditions plays a major role in inducing corrosion on any metal surface and therefore the corrosion resistance alloy can be chosen by investigating the circumstances. CRA are wide and with success used for production tubing in Smith Corrosion in oil and gas production tubing HP/HT wells worldwide as shown in the fig. 7.

CRA is the suggested choice for controlling the corrosion in hostile well conditions as a result, by accurately elect materials:

a) Prevention of corrosion namely cracking corrosion, general corrosion and localized corrosion.
b) Availability of expertise with former in depth knowledge.
c) They are capable of a large supply.
d) Established a satisfactory technology.
e) Elimination of work overs due to corrosion.

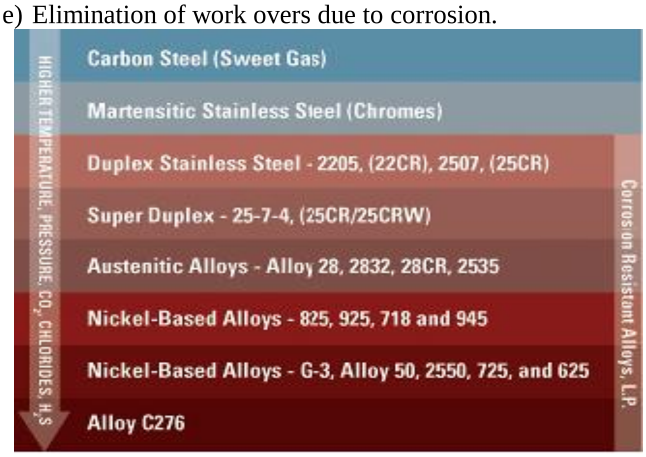

Fig. 7. Alloy Specification

E. CRA Clad Tubing

Corrosion resistance alloy clad and lined pipes are manufactured by providing a metallurgical bonding among alloys and backing steel. This kind of tubing has a wide range of application in down hole production pipes but the appropriate clad tubing along with the mechanical properties of the backing steel should to be carefully selected to avoid corrosion.

Another key drawback is that the tube needs to be joined by special thread connections that provide a leak free seal.

CRA clad is not completely sized tubing and tested for the properties of the coated surfaces. An evaluation of plasma transfer arc weld coated tubular was made in 1995.The tubing specimens were coated with an alloy of composition similar to alloy C276. Tests on hydrogen disbanding resulted in minimum amount of disbanding in just two out of the eight specimens investigated.

The disbanded regions were small in size of 10 mm in diameter and also there were regions namely inclusions or other contamination at the steel/CRA interface. Critical pitting temperature (CPT) tests in simulated H_2S-CO_2 -brine environments gave a CPT value of 177 ˚C that the pit corrosion begins at intersecting weld and surface spatter areas. When the metal was slightly machined to remove spatter, the CPT value was increased to around 204 ˚C that was analogous to wrought alloy of C276. Even though this kind of corrosion resistance alloy clad is more advantages than other corrosion resistance methods yet this not a completely developed piping [4].

IV. CORROSION MITIGATION

Current research priorities focus on pipelines corrosion control systems for monitoring internal corrosion and evaluating mitigation strategies. Mitigation strategies will be applied to reduce operating risks associated with pipelines and provide operational best practices and guidelines to the industries. Internal corrosion in pipelines was forced to account for 25% of all pipeline failures in 2011 within USA and 16% within Canada.

The plant operating people are facing a lot of difficulty in combating the corrosion in order to extend the equipment life [5]. Although many methods have been suggested to combat corrosion, they are majorly divided into three kinds which are given below:

a) Changing the material of construction for the specific application.
b) Reducing the intensity of corrosive attack by modifications in corrosive medium.
c) Avoid the contact of metal and medium by creating a barrier layer between them.

A. Change in Materials of Construction

When it is detected that the present material of construction is prone to corrosive attack, it is normally decided to change the materials of construction and select alternative material to suit the specific need. Generally, the materials used in hydrocarbon applications can be grouped broadly by means of metals or nonmetals. Each variation of these materials has its specific applications and limitations.

Corrosion resistance materials are high cost, so when changing the construction materials to corrosion resistance material will add the cost to the estimated budget. Even though the cost of the budget is increased, the life of the constructed equipment is increased and minimizes the maintenance cost by avoiding corrosion. A thorough analysis of technique and operative conditions needs to be applied before choice of a brand different material.

Some newly manufactured stainless steels, duplex stainless steels, and super duplex stainless steels have the ability to resist practically all types of corrosion. Steel mills around the world will prolong the development of more materials with different metallurgies in order to resist diverse type of corrosion in oil and gas industry. Although exotic materials like Ti and Zr can operate in the majority corrosive and high temperature environments, the initial cost is prohibitive unless equipment downtime is critical to handle. Non-ferrous materials namely copper, nickel, and copper–nickel alloys have also found good use in seawater environments, where normal materials such as carbon and stainless steels generally perform badly and fail. Selecting an appropriate grade of stainless-steel like choice of selecting a low-carbon and more stable grades can prevent corrosion of inter-granular type or weld decays if there is any welding operations are carried out.

Fig. 8 shows general corrosion inhibitor selection for oil and gas industry. Detailed study of flow conditions, corrosion mechanisms involved, and the expected life of material is important before selecting a specific metal for an application. A single material will not be a complete solution for combating corrosion in contrast there are materials made of bonding two or more alloys which are effective against corrosion. There are material which stand against stress cracking but subjected to putting corrosion due to high temperature.

B. Modification in Corrosive Medium

There are some instances where the aggressiveness of corrosion medium was minimized by adding inhibitors with the intention of reducing corrosion. The corrosion inhibition chemicals are injected as intermediate practice that is in between the process. The chemicals, their concentration, and also the frequency of injection rely upon the process medium and, normally, on the recommendations of the inhibitor manufacturer, since these chemicals, although generic in nature, are generally proprietary items. The inhibitors used are normally chromates, phosphates, and silicates, added following the recommendations of the manufacturer [5].

The knowledge in reduction of corrosion by the removal of oxygen from a fluid medium was utilized in changing the medium condition. pH of the medium is also one of the parameter which increase or decrease the rate of corrosion. There is a wide range of corrosion inhibitors are available in the commercial scale however the sensible approach along with the manufacturer's suggestions should be followed while injecting the chemical inhibitor in well.

C. Intermediate Barrier to Prevent Contact among the Metal Contact and Medium

The material and equipment life will be increased when the material is coated or creating a barrier layer to prevent the contact of medium or environmental conditions. The coating or barrier layer may be the material is painted or coated or the material is treated metallic lining. Some of the non-metallic linings are fiberglass, glass flake, and epoxy are commonly utilized in equipment's such as separators, knockout drums, and storage tanks. Nickel, zinc, and cadmium are coated in certain components namely in flanges and bolting. It is clearly understood that such arrangements are not permanent treatment and may only lengthen the life of the basic materials underneath the barrier to some extent [5].

Corrosion Inhibitors	Advantages	Limitations	Type / Dosage concentration/pH range
			The pH range can be extended upward by including stabilizer to prevent zinc precipitation.
Mixed Inhibitors			
Zinc Phosphonate Dosage [mg/L] 1 – 5 (as Zn)	A more tenacious and protective film can be formed by adding zinc. Reduction in the dosage concentration when comparing with the usage of phosphonate only.	Hardness Sensitive Reduced rate of film formation	Type - Mixed Dosage [mg/L] 1 – 5 (as Zn) Applicable pH range 7 – 8.5
Zinc Phosphonate Dosage [mg/L] 7- 20 (as PO4)	A more tenacious and protective film can be formed by adding zinc. Reduction in the dosage concentration when comparing with the usage of phosphonate only.	Biological nutrient Reduced rate of film formation	Type - Mixed Dosage [mg/L] 7- 20 (as PO4) Applicable pH range 6 – 7.5
Molybdate / Phosphonate	Improved corrosion protection can be achieved at lower concentrations of molybdate when blended with organic inhibitors.	Film formation ability remains relatively weak, and the level of protection is marginal in corrosive environments.	Type - Mixed Dosage [mg/L] 5 –20 (MoO4) Applicable pH range 7 – 8.5
Adsorption			
Benzotriazole (BTA)	Applicable but no	Toxic	Type - Adsorption

Fig. 8.General Corrosion Inhibitor Selection for Oil and Gas Industry
Courtesy (www.scielo.org.co)

V. RESULTS AND DISCUSSION

There exists an outsized quantity of expertise by means of CRA for down hole purposes. Suitably chosen CRA has a good service record, even for aggressive environment such as H_2S conditions. Even though the uncertainties were discussed above, still clad tubing is an underutilized product. In the meantime many companies face future field developments in remote (offshore) locations where there is a fundamental interest in the utilization of CRAs in wide-ranging, it would seem fitting to re-evaluate the potential for use of clad down hole tubing.

Some clad pipe manufacturers are addressing the technical challenges of manufacturing down hole tubing. While coming to prevention it has more defects in their selection of materials and metal alloys in a cost effective manner.

VI. CONCLUSION

Without implementing safety measures and having a corrosion prevention policy, corrosion creates difficulty in transporting hazardous material. A successful corrosion preventive plan is certainly not an ending practice. It initiates with an efficient design and installation of the pipeline, executing corrosion control methods, and maintaining and observing the lines.

Potential cost benefit of using clad tube instead of solid CRAs could also be smart for deep well developments wherever high pressure and extreme temperature conditions could be terribly aggressive, requiring highly alloyed materials to prevent corrosion.

Corrosion Mitigation should be done to reduce the operating risks associated with pipe lines and provide operational best practice and guidelines to the industry. Various corrosion type and their corroding agents was studied along with their mitigating methods. On the other hand, the principle of corrosion should be clearly understood in order to choose materials more effectively and then the chosen material is taken to design, fabricate, and utilize metal structures for the finest economic lifetime of facilities and safety in oil and gas industry during operations.

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AUTHORS PROFILE

Dr.T.Nagalakshmi currently working as a Professor in the department of Petroleum Engineering in AMET UNIVERSITY for the past 8 years and earlier as Assistant Professor in the department of Petroleum Engineering in Rajiv Gandhi College of Engineering Affiliated to Anna University Chennai & Accredited to AICTE New Delhi. I have experience as Project Associate in the division of soil mechanics where I underwent research in laterites and three years of experience as junior research fellow in the DST Project in the Anna University. Guiding Ph.D Full Time & Part Time Research scholars, guiding B.E & M.E Petroleum Engineering students for their final year projects. Written research articles in the field of Petroleum, geology and chemical engineering. Member in AAPG Women's Forum and in SEG .Life time member in GIAN (Global Initiative of Academic Networks) and have attended FDP "Flow assurance in Petroleum Industry" in IIT Chennai. Member in the Academic Council of AMET University and member of Board of Studies in Petroleum Engineering Department.

A.Sivasakthi currently working as an Assiatant Professor in the Department of Petroleum Engineering, Vels Institute of Science, Technology and Advanced Studies (VISTAS), Chennai. I am pursuing Ph.D. in the department of Petroleum Engineering in Academy of Maritime Education and Training (AMET), Chennai. I have published research article in the area of upstream and downstream.