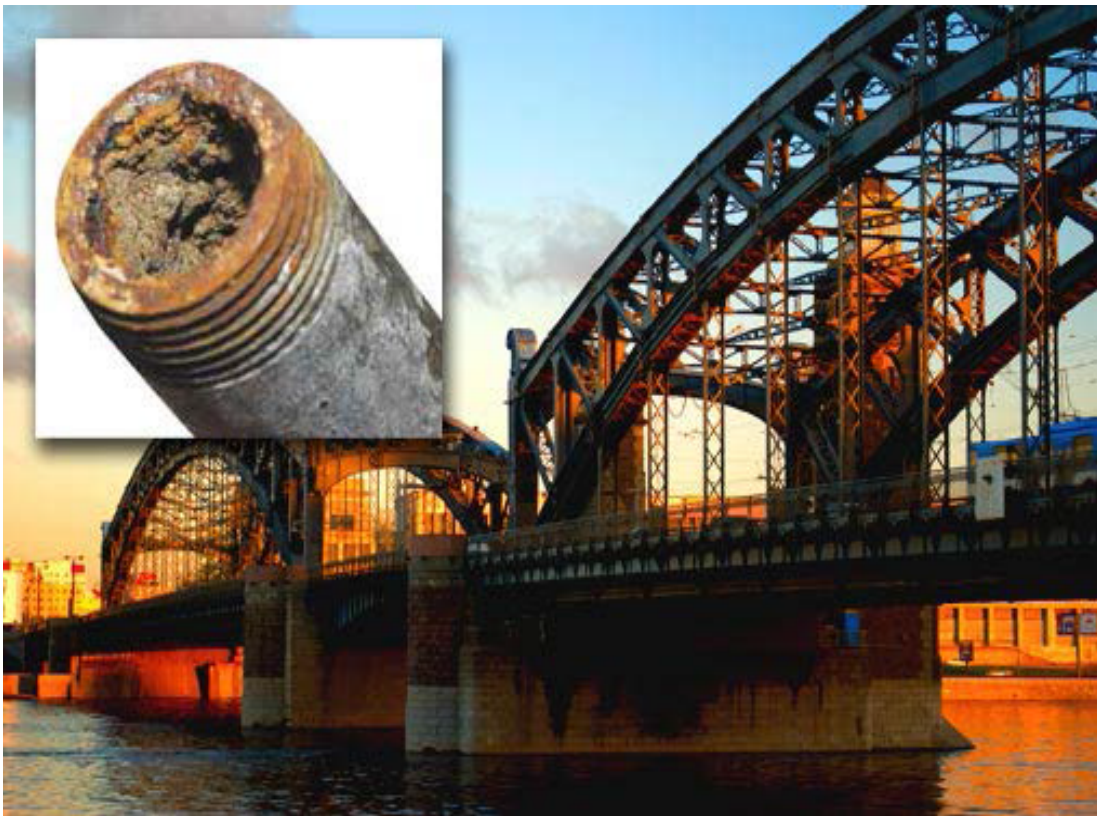


Failure Analysis of Corrosion Case Histories



Sadeq Hooshmand Zaferani

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Author: Sadeq Hooshmand Zaferani

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Preface

The design and production of this Photographic Corrosion Failures is based on actual failures which occur during operation process. During the years of installation of gas service of equipment's, many failures have been occurred in different parts.

Due to variation of materials in several parts, different aspects of failure can be investigated. First of all we collect these failed parts and categorized them according to failure types.

To earn this purpose, we shall learn about the concept of any failure and introduce failed samples consequently.

Any case history shows the conditions of any component and also the solution for any specific type. Furthermore the prevention requirements of any case have been shown at the end of any section.

A handwritten signature in black ink, appearing to read "S. Hooshmand Zaferani", written over a horizontal line.

S. Hooshmand Zaferani

About Author



Sadeq Hooshmand Zaferani is a quality control (QC) engineer in oil and gas industry; who was graduated from Petroleum University of Technology (PUT), Abadan Institute of Technology (AIT). He is the author of different publications (book and paper) in corrosion field (coating, inhibitor and environmentally friendly controlling techniques). In this field he is persuading to evaluate different methods via simulation or experiments in order to devise new techniques for controlling the corrosion process in various conditions. Furthermore, recently he has an opportunity to extend his researchers in developing of the *Renewable Energy Sources*.

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S. Hooshmand Zaferani

Introduction

Metal corrosion is one of the most critical problems which always can bring different severe consequences for facilities. Researchers in the world tend to investigate several methods for mitigating or managing the corrosion phenomenon. In this field, presence of actual issues can be so helpful to anticipate some aspects of novel techniques. The purpose of writing this book is representing the results of various analyzed observations in oil and gas industries as scientific data. On the other hand, researchers can find different helpful information about occurrences which can be conceivable in some operating conditions; therefore, they can use them on the basis of their crucial factors. Also this book represents a lot of recommendations for each part separately. This is because of the exact and accurate analysis of the case histories to depict useful ideas for better perceptions of corrosion phenomenon.

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Sadeq Hooshmand Zaferani*

Industrial consultant, Javad mostofi fakhraei, Department of technical inspection and corrosion protection, East Oil and Gas Company (EOGC), Iran

Corresponding author: Sadeq Hooshmand Zaferani, Industrial consultant, Javad mostofi fakhraei, Department of technical inspection and corrosion protection, East Oil and Gas Company (EOGC), Iran, E-mail: s-hooshmand@hotmail.com

Chapter 1

Introduction

Natural gas

Natural gas processing begins at the wellhead (Figure 1). The composition of the raw natural gas extracted from producing wells depends on the type, depth and location of the underground deposit and the geology of the area. Oil and natural gas are often found together in the same reservoir [1].

The natural gas produced from oil wells is generally classified as “associated-dissolved,” meaning that the natural gas is associated with or dissolved in crude oil. Natural gas production absent any association with crude oil is classified as “non-associated.” In 2004, 75 percent of U.S. Wellhead production of natural gas was non-associated. Most natural gas production contains, to varying degrees, small (two to eight carbons) hydrocarbon molecules in addition to methane. Although they exist in a gaseous state at underground pressures, these molecules will become liquid (condense) at normal atmospheric pressure. Collectively, they are called condensates or Natural Gas Liquids (NGLs).

The natural gas extracted from coal reservoirs and mines (coal bed methane) is the primary exception, being essentially a mix of mostly methane and carbon dioxide (about 10 percent) [1,2].

Below figure provides a typical natural gas composition. The liquefaction process requires the removal of some of the non-methane components such as water and carbon dioxide from the produced natural gas to prevent them from forming solids when the gas is cooled to about LNG temperature (-256°F). As a result, LNG is typically made up mostly of methane as shown in Figure 2 [3].

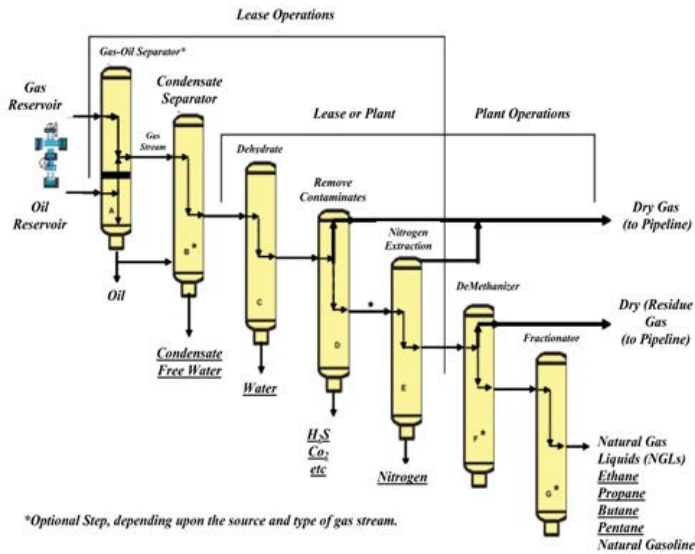
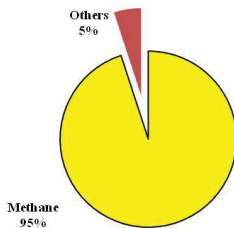


Figure 1: Generalized natural gas processing schematic [1]

Typical LNG Compositions



Typical Natural Gas Compositions

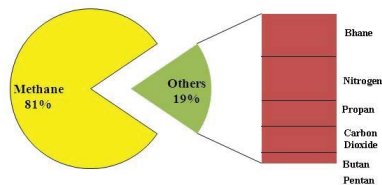


Figure 2: Typical natural gas and LNG composition [3].

The processing of wellhead natural gas into pipeline-quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil; (2) water; (3) elements such as sulfur, helium, and carbon dioxide; and (4) natural gas liquids. In addition to those four processes, it is often necessary to install scrubbers and heaters at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the natural gas does not drop too low and form a hydrate with the water vapor content of the gas stream. These natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes. The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the wells to initial processing/treating facilities. Beyond the fact that a producing area can occupy many square miles and involve a hundred or more wells, each with its own production characteristics, there may be a need for intermediate compression, heating and scrubbing facilities, as well as treatment plants to remove carbon dioxide and sulfur compounds, prior to the processing plant. All of these factors make gathering system design a complex engineering problem. In those few cases where pipeline-quality natural gas is actually produced at the wellhead or

field facility, the natural gas is moved directly to receipt points on the pipeline grid. In other instances, especially in the production of non-associated natural gas, field or lease facilities referred to as “skid-mount plants” are installed nearby to dehydrate and decontaminate raw natural gas into acceptable pipeline-quality gas for direct delivery to the pipeline grid. These compact “skids” are often specifically customized to process the type of natural gas produced in the area and are a relatively inexpensive alternative to transporting the natural gas to distant large-scale plants for processing [1,2].

Sour gas

In the oil and gas industry, “sour gas” refers to natural gas that is contaminated with hydrogen sulfide (H_2S or “sulfide”). “Sour crude,” similarly, is crude oil that contains hydrogen sulfide. These are naturally occurring conditions, but definitely not desirable. Aside from the environmental pollution problems with “high-sulfur” fuels, there are some serious corrosion problems that can affect many materials [4,5].

Sour gas development plan

A plan to explore for produce, transport and process sour gas resources from a zone or zones in an area, extending over the life of the development to depletion. The plan should portray, as best as can be done at that point in time, the ultimate well, pipelines, production facilities and infrastructure needed to deplete the pool or pools. Development plans will change in response to drilling results, production performance and economic factors. Development is generally accomplished with a number of progressive, discreet projects over the life of the pool. Plans should be updated to provide a solid basis for each project stage [6].

Transition techniques

Despite numerous efforts towards a more efficient use of energy, the energy needs are soaring. Economic growth in developing countries, constitute an additional energy price pressure. Price trends do not exclude any energy source, because they are dictated – in addition to increasing needs – by the relatively expensive existing and new alternative technological solutions. Thus, further price increases in energy can be expected in the world markets. Energy prices are important for production, business cycle, cost structure, financial markets, export revenues and real exchange rate dynamics [7].

Pipelines provide one of the safest and most reliable means for transportation of liquids and gases. However a major part of the offshore pipelines world-wide, and also in the North Sea, have reached an age of 20-30 years and are thus approaching the end of their design life. It is therefore of increasing importance for operators of such installations to be able to assess the true state of their pipelines. The installation of new pipelines is very costly, and the possibility of lifetime extension of aged pipelines should therefore be investigated. A revised use of inspection data for updating the reliability of the pipeline may support a lifetime extension. From actual measurements on a pipeline a model for predicting the initial deflection, the corresponding wavelength and the thickness of the soil cover of the pipeline is established. On this basis the structural reliability of the pipeline can be updated. The reliability calculation and decision strategy is incorporated in a Bayesian network and an optimal decision strategy for possible stone dumping on the critical locations is obtained through a cost-benefit analysis incorporated in the Bayesian network [8].

Pipelines carry products that are very vital to the sustenance of national economies and remain a reliable means of transporting oil, and gas in the world. They are generally perceived as safe with limited number of failures recorded over their service life. However, like any other engineering assets, pipelines are subject to different degrees of failure and degradation. When it occurs, pipeline rupture can be fatal and very disastrous. It is therefore

important that they are effectively monitored for optimal operation while reducing failures to acceptable safety limit.

Integrity maintenance of pipelines is a major challenge of service companies, especially those involved in the transmission of oil and gas. Two major factors have been the driving force behind this challenge. These are the need to minimize costs of operation and doing it without compromising on risk. The huge impact of pipeline failure on operational costs has necessitated the development of more effective risk management strategies to help mitigate potential risks. Ideally, most pipeline operators ensure that during design stage, safety provisions are created to comply with theoretical minimum failure rate for the pipeline. Quantitative risk assessment has been a valuable tool to operators in minimizing risk as well as complying with minimum safety requirement for engineering structures. In quantitative risk assessment, an attempt is made to numerically determine the probabilities of rupture caused by various failure mechanisms and the likely consequences of failure in terms of economic loss, human hazards, and degradation of the environment [9].

In this field, reliability plays an important role in selection of equipment for lowest long term cost of ownership. Results from various cost simulations indicate that good maintenance practices can alter outcomes of both cost and reliability. The oil & gas and petrochemical industries depend on machinery: especially pumps, compressors and their associated prime movers. The lifetime of a process plant will span several economic cycles and it should be able to operate with minimum unscheduled downtime and optimum through life cost. Optimum through life cost involves a trade-off between initial cost and through life operating and maintenance costs [10].

Causes of pipeline failures

Estimates of pipeline failure rates in different parts of the world vary depending on the criteria used to define a reportable failure or incident. In Western Europe, the rate of occurrence of all natural gas incidents leading to the release product between 1988 and 1992 is 5.7×10^{-4} (EGIG, 1993). In USA, the rate of the natural gas pipeline failures leading to death, injury or major property damage between 1984 and 1990 is 1.3×10^{-4} (EGA, 1992). Detailed analysis of the different failure data scores suggests that the difference between the USA and European figures is explained by differences in the requirements (Nessim and Pandey, 1997). The relative frequencies of the major failure causes and subcategories failure causes for USA pipelines are given in Figures 3a and b respectively. The summary of major and their subcategories are given in Table 1.

Failure causes	
Outside forces	Mechanical damage
	Ground movement
Metal loss corrosion	External
	Internal
Cracks	Environmental
	Materials and fabrication
Others (e.g. operational error, mechanical component failure)	

Table 1: Major and sub-categorization of pipeline failure causes [11].

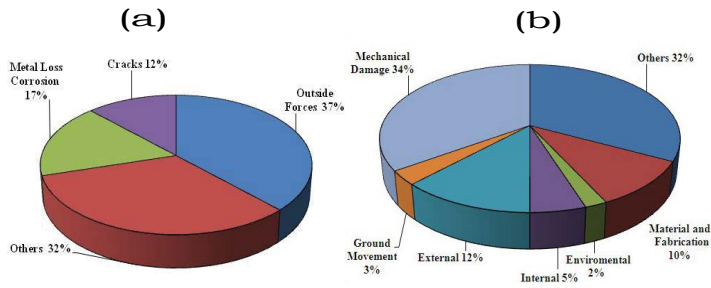


Figure 3: a) Relative frequency (%) of major causes of pipeline failures b) Relative frequency (%) of failure causes [11].

The figures show mechanical damage as the major cause of failure followed by metal loss corrosion. The frequency of corrosion leaks is low in the USA database because a large percentage of corrosion related failures involve small leaks, which are not reported in this particular database. The ratio of corrosion failures is significantly higher in databases that include incidents leading to small leaks [11].

In this Atlas various failures examples have been introduced via their operation conditions and also their properties. Finally their solution to prevent of any failure recommended.

Chapter 2

Erosion Corrosion

The term erosion applies to deterioration due to mechanical forces. When the factors contributing to erosion accelerate the rate of corrosion of a metal, the attack is called erosion corrosion. Erosion corrosion is usually caused by a corrodent, aqueous or gaseous, flowing over the metal surface or impinging on it. The mechanical deterioration may be aggravated by the presence of a corrodent, as in the case of fretting corrosion or corrosive wear. The attack takes the form of grooves, i.e., scooped-out rounded areas, horseshoe-shaped depressions, gullies, or waves, all of which often show directionality. At times the attack may be an assembly of pits. Ultimate perforation due to thinning or progression of pits, and rupture due to failure of the thinned wall to resist the internal fluid pressure are also common. All equipment exposed to flowing fluid is subject to erosion corrosion, but piping systems and heat exchangers are the most commonly affected [12].

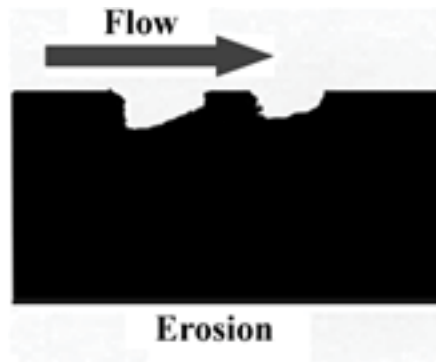


Figure 4: Schematic of erosion corrosion [13].

Phenomena: Gas Leakage**Illustration (Macro): Ball Valve****Phenomenon: Severe general
pitting****Illustration (Micro): Inner side of
Ball****Environment: Flow Line****Size: 14"****Material: Stainless Steel 316****Time in service: 29 years****Fluid: Sour Gas****Operating Pressure: 1440 Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

The mentioned ball had been used in a ball valve for 29 years. The flowing of sour gas and also corrosive liquid accumulation cause several pits on its internal surface. Because of pit distributions and also reaching to each other localized corrosion occurred.

Solution:

- Routine periodic inspection to detect and control their structure variations.
- Use of stainless steel with grade of 254SMO (21% Cr, 18% Ni, 6% Mo, 0.2% N). The reason for this selection was the need for a material resistant to alternate exposure to seawater and sulfide-containing oil.

Phenomena: Gas Leakage

Illustration (Macro): Ball Valve

Phenomenon: Wire drawing

Illustration (Micro): Outside Ball

Environment: Flow Line

Size: 14"

Material: Stainless Steel 316

Time in service: 4 years

Fluid: Sour Gas

Operating Pressure: 1200 Psig

Coating Type:-

Orientation of Specimen: 0°

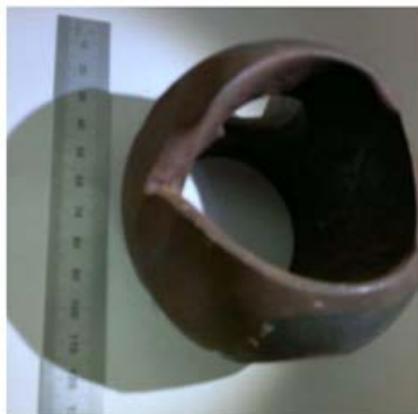


History:

This ball eroded in form of wire drawing and leakage of high pressure fluids occurred. Being scratch or local depression in the ball surface allows constricted flow of the fluid as a leak, the high flow velocity in the leak zone causes erosion and development of a channel through the seal interface.

Solution:

- The adequate inspection to detect the initiate of erosion process and control this process.
- Using the appropriate flow rate.

Phenomena: Gas Leakage**Illustration (Macro): Ball Valve****Phenomenon: Edge Severe
Erosion****Illustration (Micro): Ball****Environment: Flow Line****Size: 2"****Material: Carbon steel****Time in service: 5 years****Fluid: Sour Gas****Operating Pressure: 1440 Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

As shown in above figure, ball edges had been eroded by high rate flow. This erosion process had been done due to high speed of flowing fluid and also the presence of some liquid can intensify the erosion process.

Wall shear stress is one of the parameters that highly influence hydrodynamically induced corrosion such as erosion corrosion. Turbulent flow is frequently used in the gas industry to transport fluids in order to increase the transportation efficiency at a minimized cost. Also articles and other geometrical changes in the flow give rise to higher shear stress.

Solution:

- The adequate inspection to detect the initiate of erosion process and control this process.
- Replacing a carbon steel body with 316SST. (25).

Phenomena: Gas Leakage

Illustration (Macro) Choke valve

**Phenomenon: Severe Flow
Erosion**

**Illustration (Micro): Nozzle
Holder**

Environment: X-Tree

Size: 2"

Material: Tungsten carbide

Time in service: 3 years

Fluid: Sour Gas

Operating Pressure: 4500 Psig

Coating Type:-

Orientation of Specimen: 90°



History:

High gas flow and impingements of hard particles (eg: sands) carried by a fluid on a surface will cause additional mechanical damage.

Solution:

- The adequate inspection to detect the initiate of erosion process and control this process.
- In this case, reducing the flow rate may not be sufficient to reduce the severity of attack. Filtering out the erosive particles may be the best solution.

Phenomena: Leakage

Illustration (Macro): Choke valve

**Phenomenon: Severe Flow
Erosion**

Illustration (Micro): Needle Part

Environment: X-Tree

Size: 2"

Material: SS410

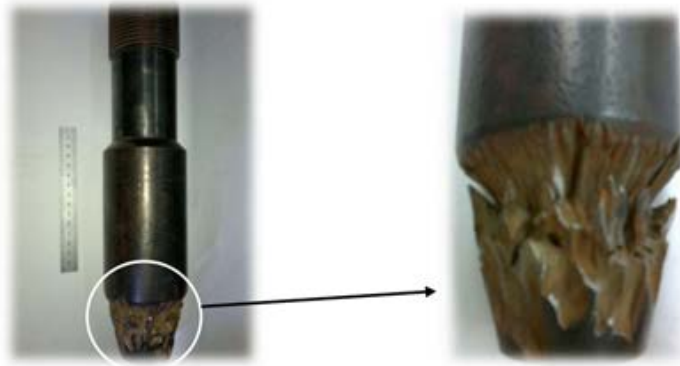
Time in service: 3 years

Fluid: Sour Gas

Operating Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: -



History:

This erosion process had been done because of high speed of flowing fluid.

Solution:

- Control the flow rate.

Phenomena: Gas Leakage**Illustration (Macro): Control Valve****Phenomenon: Flow Aberrations****Illustration (Micro): Outlet Flange****Environment: Flow Line****Size: 3"****Material: A216-WCC****Time in service: 5 years****Fluid: Sour Gas****Operating Pressure: 1440 Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

The mentioned control valve had been carried out in sour gas service. After 5 years of operation, severe erosion corrosion and also groove shape erosion observed in outlet flange. Over rate operation can be assumed as the main reason for this failure. In other words, out gassing is a very fast, hard-to-predict phenomenon that occurs when the pressure of a fluid drops below the saturation pressure of a dissolved gas. Once this point is reached, the gas separates from the solution and produces high velocity, erosive vapor droplets. This process is evident when the liquid and gas exiting the control valve have dissimilar molecular weights.

Solution:

- Proper selection of control valve body and trim materials is the first step in combating erosion-related damage and could mean the difference between an unplanned shutdown and continued operation.
- Materials with high chromium and molybdenum content generally provide increased resistance to erosion and wear.
- Using the appropriate flow rate.

Phenomena: Large perforation

Illustration (Macro): Well Tubing

Phenomenon: Flow Jet Erosion

Illustration (Micro): Coupling

Environment: Sour Gas Well

Size: 4 ½"

Material: API 5CT – L80 Type 1

Time in service: 30 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 90°



History:

Leakage failure occurred as the mention hole in the coupling body. Creation of the perforation can be initiated via microstructure defect, therefore fluid rate and also its velocity intensifies the growth of the hole.

Solution:

- It is recommended to use of this material with clearer microstructure and lower inclusions.

Phenomena: Valve Passing**Illustration (Macro): Control Valve****Phenomenon: Flow Erosion****Illustration (Micro): Cage****Environment: Flow Line****Size: 2"****Material: Stainless Steel 316****Time in service: 2 years****Fluid: Sour Gas****Operating Pressure: 4800 Psig****Coating Type:-****Orientation of Specimen: 90°****History:**

Throttling process of control valve can be subjected to more severe conditions than other system components. The shock waves and pressure fluctuations resulting from these high velocity collapses can also cause vibrations, noise, accelerated corrosion, as well as limited valve capacity.

Furthermore the mentioned cage had been fabricated by Stainless steel 316 with hole diameter of 2 mm. Because of sensitization of SS 316 in chloride the selected material cannot act as a resistive body against of sour environment and also chloride, it had been destroyed by corrosive fluid with high rate.

Solution:

- Increasing the hole diameter.
- Hardened stainless steels including S17400 and S41000 provide excellent hardness and durability against chloride sensitization for using as trim materials.
- Designing valves to resist the deleterious effects of the throttling process fluid is only as effective as the valve sizing and selection process itself.
- A control valve designed with hardened trim material could last almost indefinitely on low pressure drop service conditions.

**Phenomena: Thickness
Dedagration****Illustration (Macro): Flange****Phenomenon: Intense,
widespread pitting on ID of steel****Illustration (Micro): Flange Inner
Side****Environment: Flow line****Size: 4 1/16"****Material: A 350 LF3****Time in service: 7 years****Fluid: Sour Gas****Operating Pressure: 4800 Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

The mentioned flange fabricated from material which is not appropriate for using in sour gas service according to NACE MR-01-75. Furthermore inclusions content affect on the quality therefore the unsuitable cleanliness of the selected alloy and also MnS containing reduce the resistance of the fabricated flange against the sour gas corrosion.

Solution:

- Using of alloy with lower inclusion and clear microstructure.
- Using of suitable corrosion inhibitor.
- Clad the internal surface of flange with high resistance alloys (eg: Inconel 625 +Inconel 825, Duplex 22% and 25%)

**Phenomena: Thickness
Dedagration**

Illustration (Macro): Grit Trap

**Phenomenon: Severe erosion
Corrosion**

Illustration (Micro): Bottom Cap

**Environment: Up stream flow
line**

Size: 6"

**Material: A 105 N clad with
Tangestan Carbide**

Time in service: 11 years

Fluid: Sour Gas

Operating Pressure: 4800Psig

Coating Type:-

Orientation of Specimen: 0°



History:

The severe erosion caused by high speed flow and finally the thickness thinning will be resulted.

The contacting of sands and also the disbanded tungsten parts of wellhead parts with high speed to grit trap cap cause the severe erosion.

Solution:

- Routine periodic inspection of wellhead equipments to detect of disbonded parts and prevention of contact to grit trap cap.
- Using of internal cladding layer with Inconel 625 ,Inconel 825 , Duplex 22% and 25% alloys.

Phenomena: Desert sand dune appearance	Illustration (Macro): Choke Valve	Phenomenon: Cavitations, Severe general pitting
Illustration (Micro): Flange	Environment: X-Tree	Size: 2 1/16"
Material: SS 410	Time in service: 4 Years	Fluid: Sour Gas
Operating Pressure: 4800 Psig	Coating Type:-	Orientation of Specimen: 0°

**History:**

Impingement of hard particles carried by a fluid on a surface will cause additional mechanical damage. When the fluid is corrosive, the particle impingement can remove protective films ordinary resistance to fluid shear, accelerating the corrosion. In this case, reducing the flow rate may not be sufficient to reduce the severity of attack.

Solution:

Filtering out the erosive particles may be the best solution.

- Using appropriate rate.
- Using of alloys with high corrosion resistance

Phenomena: Gas Leakage

Illustration (Macro): Chock Valve Body

Phenomenon: Jet Flow Erosion

Illustration (Micro): -

Environment: Flow Line

Size: -

Material: Carbon steel

Time in service: 9 years

Fluid: Sour Gas

Operating Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

Over rating of gas flow is the main result of this phenomenon.

Solution:

- Selecting material with high resistance against erosion.
- Using of metallic coatings with high resistance.
- Setup in system with allowable fluid rates.

Phenomena: Gas Leakage

Illustration (Macro): Choke Valve

Phenomenon: Flow Jet Erosion

Illustration (Micro): Flow Color

Environment: X-Tree

Size: -

Material: SS 410

Time in service: 12 years

Fluid: Sour Gas

Operating Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

High, localized velocities, vortex flow, jet, and direct increase the rate of erosion-corrosion.

Solution:

- Controlling the flow rate.

Phenomena: Gas Leakage

Illustration (Macro): Choke valve

Phenomenon: Flow Jet Erosion

Illustration (Micro): Flow color

Environment: X-Tree

Size: -

Material: SS 410

Time in service: 4years

Fluid: Sour Gas

Operating Pressure: 4500 Psig

Coating Type: Tungsten carbide

Orientation of Specimen: 90°



History:

High, localized velocities, vortex flow, jet, and direct increase the rate of erosion-corrosion.

Solution:

- Controlling the flow rate.

Phenomena: Gas Leakage	Illustration (Macro): Control Valve	Phenomenon: Jet Flow Erosion
Illustration (Micro): Outlet Flange	Environment: Flow line	Size: 3"
Material: A216 WCC	Time in service: 7 Years	Fluid: Sour Gas
Operating Pressure: 4800 Psig	Coating Type:-	Orientation of Specimen: 0°



History:

The mentioned control valve had been carried out in sour gas service. After 7 years of operation, severe erosion corrosion and also groove shape erosion observed in the outlet flange. Over rate operation can be assumed as the main reason for this failure.

The fluid velocity plays a great role in corrosion rate. When the velocity is very high, the impact of the particles present in the fluid upon the inner wall of the equipment tends to remove the protective oxide layer and some of the metals under it causing erosion and thus lead to erosion-corrosion with time.

Solution:

- Using appropriate rate.
- Using of alloys with high corrosion resistance.

Phenomena: Valve Passing

Illustration (Macro): Gate Valve

Phenomenon: Jet Flow Erosion

Illustration (Micro): Gate

Environment: Flow Line

Size: 2"

Material: C.S 4140

Time in service: 3years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 90°

**History:**

In service, high-pressures and flow rates are often encountered in the pipelines, which convey the fluid from the well-head and the ability of the valve to seal off these flows, when required, is of paramount importance. The Gate valve was used to open, or shut off, fluid flows and was not intended for regulating or throttling; any attempt to use it in this way will bring about a rapid deterioration in its ability to shut off flow.

The predominant wear processes on this gate is erosion, and two- and three-body abrasion caused by the presence of sand in the hydrocarbon fluid. Sand is often entrained in the fluid owing to the geology in which the reservoirs are located.

This damage can compromise the hard-faced sealing surfaces and thus containment of hydrocarbon fluids.

This damage occurs on opening and closing of the valves: when fully open or fully closed, damage is minimal. However, when partially open, swirling or jetting flow leading to low-angle erosive attack on the valve interior can occur. Abrasion can also be present, especially if sand becomes trapped between the gate and the sealing surfaces. The valve can also be subjected to other mechanisms such as sliding wear and galling.

It is assembled dry and adhesive wear can result when the valve enters service.

Damage of this type can significantly affect the performance and lead to its premature withdrawal from service. The most common manifestations of damage are leakage in the closed position, failure to open or close on demand, delayed operation and internal leakage.

Solution:

- At present, the most widely used coating for seal faces in gate valves are tungsten carbide, with the balance being divided between bulk and sprayed Stellite, low-alloy steel and carbon steel.
- It has been found that the addition of Cr to WC-Co inhibits to a large extent the decomposition of WC-Co as well as having a beneficial effect on the erosion resistance.
- Of the various spraying processes, the high-velocity oxy-fuel (HVOF) method has been found to deposit coatings with significantly lower levels of carbide decomposition and phase transformation .

Phenomena: Gas Leakage

Illustration (Macro): Elbow 90°

Phenomenon: Severe erosion corrosion

Illustration (Micro):-

Environment: Flare line

Size: 6"

Material: A234-WPB

Time in service: 1 year

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

Presence of liquids and also sends intensify the erosion rate and also metal loss. Otherwise direction of flow is perpendicular to elbow wall.

Solution:

- Setup a suitable separator and also grinded parts to separate the sands and suspended liquids can be applicable.

Preventing comments

Generally, erosion/corrosion can be controlled by changing the materials of construction to ones that are more corrosion resistant and compatible with the fluid [14].

An example of this would be replacing a carbon steel body with 316SST [14].

Service	Body	Trim
Standard	Carbon St.WCB or AISI 4130	316 & satellite Gr. 6
Sour	Carbon St.WCB or AISI 4130 (NACE)	316 & satellite Gr. 6 (NACE)
Corrosive sour	Carbon St.WCB or AISI 4130+inconel in seal area ASTM A182 F316	316 & satellite Gr. 6 (NACE)

High duty production	Carbon St. WCB or AISI 4130	17-4 PH & tungsten carbide
High duty production with contaminates	Carbon St. WCB or AISI 4130	17-4 PH & tungsten carbide with protected seat design
High duty production with contaminates, sour	Carbon St. WCB or AISI 4130+inconel, Duplex St. St. Super Duplex St. St.	Duplex st.st./super duplex st.st & tungsten carbide with protected seat design
Water injection	Carbon St. WCB or AISI 4130	316 & satellite Gr. 6
Water injection-high duty	Carbon St. WCB or AISI 4130+inconel in seal area St. St. CF8M or Duplex St. St.	316 & satellite Gr. 6 (NACE) & tungsten carbide/advanced ceramics

Table 2: Materials of construction [15].

Also erosion corrosion is affected by velocity, turbulence, impingement, presence of suspended solids, temperature, and prevailing cavitation conditions. The acceleration of attack is due to the distribution or removal of the protective surface film by mechanical forces exposing fresh metal surfaces that are anodic to the uneroded neighboring film. A hard, dense, adherent and continuous film such as on stainless steel is more resistant than a soft, brittle film as on lead. The nature of the protective film depends largely on the corrosive itself.

In most metals and alloys corrosion rates increase with increased velocity, but a marked increase is experienced only when a critical velocity is reached. Turbulence is caused when the liquid flows from a larger area to a small-diameter pipe, as in the inlet ends of tubing in heat exchangers. Internal deposits in the pipes or any obstruction to the flow inside a pipe by a foreign body, such as a carried-in pebble, can also cause turbulence.

Impingement, direct impact of the corrodent on the metal surface, occurs at bends, elbows, and tees in a piping system and causes intense attack. Impingement is also encountered on the surfaces of impellers and turbines in areas in front of inlet pipes in tanks and in many other situations. The attack appears as horseshoe-shaped pits with deep undercut and the end pointing in the direction of flow.

Soft and low-strength metals such as copper, aluminum, and lead are especially susceptible to erosion corrosion. So are the metals and alloys that are inherently less corrosion resistant, such as carbon steels.

Stainless steels of all grades, in general, are resistant to erosion corrosion. The addition of nickel, chromium, and molybdenum further improves their performance. Stainless steels and chromium steels are resistant as a result of their tenacious protective surface films. As a rule, solid solution alloys provide better resistance than alloys hardened by heat treatment because the latter are heterogeneous in structure.

Cast irons usually perform better than steel. Alloy cast irons containing nickel and chromium show better performance. Duriron containing 14.5% silicon gives excellent performance under severe erosion corrosion conditions. Impingement attack can be avoided by smoothing the bends in a piping system. Increasing the pipe diameter will ensure a laminar flow and less turbulence [12,16].

Chapter 3

Pitting Corrosion

Pitting is a form of localized corrosion that is primarily responsible for the failure of iron and steel hydraulic structures. Pitting may result in the perforation of water pipe, making it unusable even though a relatively small percentage of the total metal has been lost due to rusting. Pitting can also cause structural failure from localized weakening effects even though there is considerable sound material remaining. The initiation of a pit is associated with the breakdown of the protective film on the surface. The main factor that causes and accelerates pitting is electrical contact between dissimilar metals or between what are termed concentration cells (areas of the same metal where oxygen or conductive salt concentrations in water differ). These couples cause a difference of potential that results in an electric current flowing through them water or across moist steel, from the metallic anode to a nearby cathode. The cathode may be brass or copper, mill scale, or any other portion of the metal surface that is cathodic to the more active metal areas. However, when the anodic area is relatively large compared with the cathodic area, the damage is spread out and is usually negligible. When the anodic area is relatively small, the metal loss is concentrated and may be serious. For example, it can be expected when large areas of the surface are generally covered by mill scale, applied coatings, or deposits of various kinds but breaks exist in the continuity of the protective material. Pitting may also develop on clean, bare metal surfaces because of irregularities in the physical or chemical structure of the metal. Localized dissimilar soil conditions at the surface of steel can also create conditions that promote pitting. Figure 5 shows diagrammatically how a pit forms when a break in the mill scale occurs.

If an appreciable attack is confined to a small area of metal acting as an anode, the developed pits are called shallow. The ratio of deepest metal penetration to average metal penetration, as determined by weight loss of the specimen, is known as the pitting factor. A pitting factor of 1 represents uniform corrosion [17].

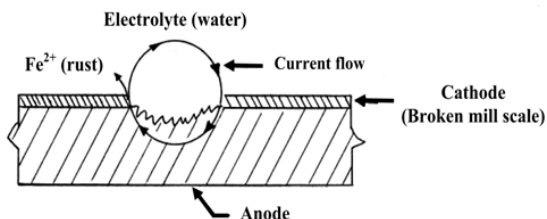


Figure 5: Formation of pit from break in mill scale [17].

Performance in the area of pitting and crevice corrosion is often measured using Critical Pitting Temperature (CPT), Critical Crevice Temperature (CCT), and Pitting Resistance Equivalent Number (PREN). As a general rule, the higher the PREN, the better is the resistance. Alloys with similar values may differ in actual service. The pitting resistance number is determined by the chromium, molybdenum and nitrogen contents.

Pitting corrosion (sometimes only called pitting) occurs on more or less passivated metals and alloys in environments containing chloride, bromide, iodide or perchlorate ions when the electrode potential exceeds a critical value, the pitting potential (Figure 6), which depends on various conditions. The pitting potential is not a thermodynamically defined potential and depends for one thing upon the rate of potential increase when the polarization curve is recorded. This form of corrosion is characterized by narrow pits with a radius of the same order of magnitude as, or less than, the depth. The pits may be of different shape, but a common feature is the sharp boundary (Figure 7). Pitting is a dangerous form of corrosion since the material in many cases may be penetrated without a clear warning (because the pits often are narrow and covered) and the pit growth is difficult to predict. This is connected to the fact that the extent and the intensity of pitting corrosion is difficult to measure because the number and size of pits (diameter and depth) vary from region to region and within each region. Short-term testing in the laboratory for determination of pit growth is also problematic because, under realistic conditions, it may take long time, e.g. many months, before the pits become visible. Another problem is that the critical size, i.e. the maximum pit depth, increases with increasing surface area [17].

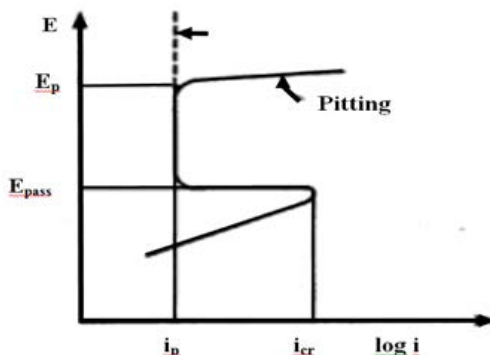


Figure 6: Anodic polarization curve for an active-passive metal in an environment causing pitting corrosion [17]. E_p = pitting potential; E_{pass} = passivation potential; i_{cr} = critical density and i_p = passive current density

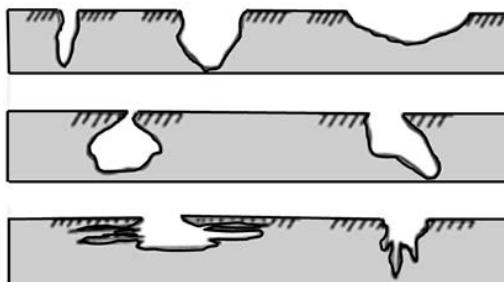


Figure 7: Different shapes of corrosion pits [16].

Influencing factors

Factors of general significance for pitting are:

pH and chloride concentration: The pitting potential and pitting resistance normally increase with increasing pH and decreasing chloride concentration.

Flow velocity: When pitting is initiated, an aggressive environment is established within the pit, and this is combined with an increased pH at the adjacent free surface. The increased pH gives an increased resistance to initiation of new pits around the first one formed (this is the case, e.g. for unalloyed steel, but it is more uncertain with respect to aluminium). If there is no movement of the liquid, these conditions will be conserved, and the result is large and few pits. Liquid flow gives a higher probability for washing away the aggressive environment in the pit, and at the same time it increases the transport of oxygen to the active area, so that the pit may be passivated before it gets the chance to grow to a considerable size. The alkaline layer around an active pit is also washed away to a higher extent, and pit initiation in the neighbourhood of an active pit occurs more easily. This means that increased flow velocity results in smaller but more numerous pits, which makes pitting corrosion less serious.

The gravity force: Horizontal top surfaces are often heavily pitted, while underside surfaces are hardly, or not at all, attacked. Vertical surfaces are intermediate as to the extent of pitting. The reason is that the aggressive environment in the pits has a higher density than pure water.

Cu²⁺ and Fe³⁺ ions: They favour pit initiation and accelerate pit growth because they lead to increased potential. The Cu ions have a double effect because Cu is precipitated on the material surface and forms efficient cathodes.

Metallurgical properties: Impurities and inclusions are important, e.g. AlFe secondary phase, which contributes to the localization of pits on Aluminium because

- 1) The oxide film on top of and around the inclusion is weak, thin and stressed,
- 2) Such inclusions are efficient cathodes.

Pitting of this type will usually last only until the pits are so large that the inclusions are falling out.

The insulating ability of the oxide: If the oxide insulates efficiently, the surface is inactive as a cathode. This is to a certain extent the case for Aluminium in seawater; which is the direct reason for the relative slow growth of pits in this case.

Surface roughness: The main trend is that smooth surfaces get few, large pits while rough surfaces get numerous smaller pits.

Temperature: Increasing temperature gives usually decreasing pitting potential and increasing liability to pitting corrosion.

Galvanic contact with a more noble material increases the tendency to and the rate of pitting corrosion (the corrosion potential is lifted) [17].

Phenomena: Gas Leakage

Illustration (Macro): Transition pipeline

Phenomenon: Isolated intense pit

Illustration (Micro): -

Environment: Flow Line

Size: 2"

Material: API 5L-X42

Time in service: 7 years

Fluid: Sweet gas

Operating Pressure: 1100 Psig

Coating Type: Epoxy

Orientation of Specimen: 0°



History:

This localized corrosion exists as pitting corrosion because of lacking cathodic protection. This thickness thinning cause a failure in static test in 900 psig. Also metallic and nonmetallic inclusions often play a decisive role in the start of a corrosion pit.

Solution:

- Using appropriate cathodic protection according to suitable standards.

Phenomena: Gas Leakage**Illustration (Macro): Steel flange****Phenomenon: Intense,
widespread pitting****Illustration (Micro): Inner side****Environment: Flow line****Size: 4 1/16"****Material: A105N****Time in service: 5 months****Fluid: Sour Gas****Operating Pressure: 4800Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

Despite of suitable material of mentioned flange (A 105 N), non-metallic inclusions affect on this degradation.

Solution:

- The use of more pit resistance material on a partial basis is also employed (for example , use of weld overlays to improve resistance of inner flange surface)

**Phenomena: Thickness
Dedegration**

**Illustration (Macro):
Transmission pipeline**

**Phenomenon: Localized
thickness thinning**

Illustration (Micro): Inside wall

Environment: Underground

Size: 6"

Material: API 5L-X42

Time in service: 1 year

Fluid: Sweet Gas

Operating Pressure: 1200 psi

Coating Type: Bitosil

Orientation of Specimen: 0°



History:

In this pipe line non-metallic inclusions act as initiation point for pitting. Furthermore liquid accumulation in bottom of the pipe line intensifies pit growth.

Solution:

- Alternatively use more resistance materials.
- Using a separator to remove liquids of flow line.

**Phenomena: Thickness
Dedagration**

**Illustration (Macro): Transition
pipeline**

**Phenomenon: ID Severe localized
pitting corrosion**

**Illustration (Micro): Corroded
inside surface**

Environment: Flow Line

Size: 6"

Material: API 5L-X42

Time in service: 1 year

Fluid: Sweet Gas

Operating Pressure: 1200 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

The main reason for this phenomenon is corrosive liquid accumulation. As observed the mentioned part of pipe shows thickness thinning, groove and root pass removing due to unsuitable material fabrication and also sand erosion. This observation provides localized erosion corrosion which exhaust as leakage. Presence of inclusions helps to increase the metal dedagration.

Solution:

- Adequate inspection during fabrication
- Using of appropriate material for this service conditions

Phenomena: Leakage

Illustration (Macro): -

Phenomenon: Pitting Corrosion

Illustration (Micro): Stem

Environment: X-Tree

Size:-

Material: SS 410

Time in service: years

Fluid: Sour Gas

Operating pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

Pitting corrosion occurs at passivated metal surfaces of mentioned during the access of so-called aggressive anions. Halides very effectively attack passivating thin oxide layers, leading to an intense localized dissolution of the metal surface, which is otherwise protected by the passive layer against general dissolution. The restriction of the dissolution to pits within a large passivated metal surface, which may serve as a large cathode for the reduction of oxidants such as dissolved oxygen, leads to fast perforation of the metal, which weakens the construction and thus causes large economic losses and safety problems.

Solution:

Using of

- Appropriate materials with high quality in microstructure. It can be used as cladding layer.

Phenomena: Large perforation**Illustration (Macro): Transition pipeline****Phenomenon: Preferential corrosion of weld****Illustration (Macro): Inside pipe wall****Environment: Under ground****Size: 8"****Material: API 5L-X42****Time in service: 1year****Fluid: Sweet Gas****Operating Pressure: 1440Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

Accumulations of liquids and also sands with the transition gas cause deep pits in the welding line and remove root pass. The mentioned failure called the localized corrosion attack adjacent to the welded zone [heat affected zone (HAZ)], as weld decay. The heat affected zone (a narrow zone) becomes susceptible to intergranular attack because it reached the sensitization temperature range during welding (400–900°C), whereas the temperature of the weld region is much higher. Hence, the region adjacent to the weld fails by intergranular corrosion, commonly called 'weld decay.' The rest of the base metal remains unaffected.

The effect of the welding process on the severity of weld decay varies according to the process and the plate thickness so that no single recommendation is possible for every thickness of plate if resistance to attack is essential. The severity of weld decay correlates quite well with sensitisation times as calculated from recorded weld heating cycles.

Corrosion of weld to perforation resulted either from improper heat-treatment or, more likely, from incomplete penetration of the weld causing crevice corrosion.

Solution:

Using of

- Appropriate materials with high quality in microstructure.
- Suitable welding electrodes and also welding process.

Phenomena: Gas Leakage**Illustration (Macro): Well head equipment****Phenomenon: Severe general pitting****Illustration (Micro): Upper Flow Tube****Environment: Sour gas well****Size: -****Material: Stainless Steel 410****Time in service: 1 year****Fluid: Sour Gas****Operating Pressure: 4500 Psig****Coating Type:-****Orientation of Specimen: 90°****History:**

As shown in the surface of tube was destroyed by pitting corrosion. The heat treatment process and also sand blast surface preparation remove the anticorrosion protective coating and reducing the resistance ability against sour gas corrosion. Sulfide inclusions play a major role in pitting initiation on iron alloys, among them stainless steels. It is worth drawing attention to some of their physicochemical and metallurgical properties. Sulfur is combined with Mn to form manganese sulfides, MnS, which act as pitting sites in current corrosive media.

Following the sulfur content of the steel and the metallurgical processing, MnS is found either isolated or stuck to other inclusions (generally oxides) or even combined in complex inclusions.

Solution:

- Using the alloys with high corrosion resistance ability against sour gas corrosion (eg: 17-4PH, MP35N, Inconel 718)

Prevention comments

The best way to prevent pitting is appropriate materials selection. Among Aluminium alloys, those alloyed with magnesium and/or manganese and the commercially pure grades are the best ones. These perform quite well in seawater.

Aluminium alloys with Cu and Zn are generally less corrosion resistant. In stainless steels, increased content of Cr as well as N and Mo gives higher resistance against pitting, while Si, S and C have the opposite effect. Modern high-alloy steels with higher content of Mo (6–7%) have very good pitting resistance.

Some Ni alloys and particularly titanium are even better.

If general corrosion can be accepted, pitting corrosion can be avoided by selecting materials that are sufficiently active in the environment in question.

Cathodic protection can also be applied to prevent pitting. Regarding Aluminium, strong cathodic polarization should be avoided because this can lead to a large increase of pH close to the metal surface, which can cause so-called alkaline corrosion.

Use of sacrificial anodes of Zn or Al alloys is therefore safer than impressed current [12,17,18].

Chapter 4

Hydrogen Induced Cracking

There are several categories of hydrogen phenomena that are localized in nature. Atomic hydrogen, and not the molecule, is the smallest atom and it is small enough to diffuse readily through a metallic structure. When the crystal lattice is in contact or is saturated with atomic hydrogen, the mechanical properties of many metals and alloys are diminished. Nascent atomic hydrogen can be produced as a cathodic reaction when certain chemical species are present which act as negative catalysts (i.e. poisons) for the recombination of atomic to molecular hydrogen.

If the formation of molecular hydrogen is suppressed, the nascent atomic hydrogen can diffuse into the interstices of the metal instead of being harmlessly evolved as a gaseous reaction product. There are many chemical species which poison this recombination (e.g. cyanides, arsenic, antimony, or selenium compounds). However, the most commonly encountered species is hydrogen sulfide (H₂S), which is formed in much natural decomposition, and in many petrochemical processes.

The mechanism of HIC has not been definitely established. Various factors are believed to contribute to unlocking the lattice of the metal, such as hydrogen pressure at the crack tip, the competition of hydrogen atoms for the lattice bonding electrons, the easier plastic flow and dislocation formation in the metal at the crack tip in the presence of hydrogen, and the formation of certain metal hydrides in the alloy. The following phenomena have also been commonly reported in relation to hydrogen weakening of metallic components [19].


Forms of Hydrogen Damage

There are a number of different forms of hydrogen damage that apply to metallic materials, resulting from the combined factors of hydrogen and residual or applied tensile stresses. Hydrogen damage can result in cracking, embrittlement, loss of ductility, blistering and flaking, and also micro perforation. These and other types of hydrogen damage are briefly described in the following sections. Table 3 provides lists of general types of metals that are typically susceptible to the various types of hydrogen attack.

Hydrogen Induced Cracking	Hydrogen Embrittlement	Loss in Tensile Ductility	High Temperature Hydrogen Attack	Blistering	Shatter Cracks, Flakes, Fisheyes	Micro-perforation	Degradation in FLOW properties	Metal Hydride formation
Steels	Carbon and low-alloy steels	Steels	Carbon and low-alloy steels	Steels	Steels (forging and castings)	Steels (compressors)	Iron	V
Nickel-alloys		Nickel-alloys		Copper			Steels	Nb
Metastable stainless steel		Be-Cu		Aluminium			Nickel-alloys	Ta

Titanium-alloys	Bronze	Ti
	Aluminium alloys	Zr
		U

Table 3: Materials Susceptibilities to Hydrogen Damage [20].

<u>CHAPTER 4</u>	CORROSION CASE HISTORY	<u>HYDROGEN INDUCED CRACKING</u>
Phenomena: Explosion	Illustration (Macro): Pipeline	Phenomenon: Freezing liquid crack
Illustration (Micro): -	Environment: Above ground pipe line	Size: 3"
Material: API 5L-X42	Time in service: 20 years	Fluid: Sweet gas and its liquid compounds
Operating Pressure: 1480 Psig	Coating Type:-	Orientation of Specimen: 0°
		
<p>History: The sudden reduction of temperature degree causes the freezing of inlet liquid and carries out a crack in the mentioned pipe.</p>		
<p>Solution:</p> <ul style="list-style-type: none"> It's recommended to used as underground pipeline or covered by a protective coating to protect against temperature degree changing. 		

Phenomena: Expansion crack

Illustration (Macro): Equal TEE

Phenomenon: Temperature variation crack

Illustration (Micro): -

Environment: Flow Line

Size: 3"

Material: A234-WPB

Time in service: 5 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

The sudden reduction of temperature degree causes the freezing of inlet liquid and carries out a crack in the TEE body. Also the wrong material selection (A234-WPB) can be assumed as another reason for this failure.

Solution:

- It is recommended to use a material with more resistance against under-zero temperature such as A860-WPHY 42.

Phenomena: Explosion

Illustration (Macro): Line pipe

Phenomenon: Longitudinal crack
among of pipe and perpendicular

Illustration (Micro): -

Environment: Valve Ventilation

Size: 2"

Material: Stainless Steel Series
400

Time in service: 22 years

Fluid: Sour Gas

Pressure: 26.5 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

Basically the mentioned pipe was welded with residual stress, there the effect of low temperature in cold session and fluid accumulation cause a crack in the pipe body.

Solution:


- Stress removing of installed pipe and also prevent of liquid accumulations furthermore it is necessary to fix with clams to control and reducing of vibrations.

Phenomena: Explosion**Illustration (Macro): Line pipe****Phenomenon: Fish Eye Cracking****Illustration (Micro): Pilot pipe
line****Environment: Above ground****Size: 2"****Material: 5L-Gr B****Time in service: 8 years****Fluid: Sweet gas****Operating Pressure: 1200Psig****Coating Type:-****Orientation of Specimen: 0°****History:**

Hydrogen embrittlement causes dropping of elongation and reduction in area on the mentioned nipple. On fracture surfaces, so called "fish eyes" can be found, oriented perpendicularly to the applied tensile stress. Fish eyes initiate nearly always on non-metallic inclusions and propagate by cleavage or quasi cleavage fracture. Shape and orientation of inclusions can influence initiation and shape of fish eyes. An inclusion can act as a fish eye initiator only if the plasticity of the matrix, i. e. its capacity to support three axial stresses, is decreased.

Solution:

- Remove the residual stress.
- Using the material with low inclusions.

<u>CHAPTER 4</u>	CORROSION CASE HISTORY	<u>HYDROGEN INDUCED CRACKING</u>
Phenomena: Explosion	Illustration (Macro): Equal TEE	Phenomenon: Stress oriented HIC
Illustration (Micro): -	Environment: Above ground	Size: 2"
Material: A234 WPB	Time in service: 22 years	Fluid: Sour Gas
Operating Pressure: 1200Psig	Coating Type: Epoxy	Orientation of Specimen: 0°
		
<p>History: The hardness of the mentioned was more than accepted value for servicing in sour gas (22 HRC). Also presence of stress and H₂S gas causes stress oriented HIC.</p>		
<p>Solution:</p> <ul style="list-style-type: none"> • Reducing hardness value. • Removing stress. 		

Preventing comments

In order to produce preventative measures, both the source of the hydrogen and the degradation mechanisms must be known at least approximately. As important measures in the prevention of hydrogen damage, the following points can be mentioned [16]:

- Material-selection of suitable material,
- Medium (environment)-it is not easy to influence, possibly by the addition of inhibitors,
- Design-avoid notches, slots and sharp transitions, avoid local plastic deformation.

Base solutions to various hydrogen degradation forms are as follows:

1. Internal cracking or blistering

- Use of steel with low levels of impurities (i.e. Sulfur and Phosphorus).
- Modifying environment to reduce hydrogen charging.
- Use of surface coatings and effective inhibitors.

2. Hydrogen embrittlement

- Use of lower strength (hardness) or high resistance alloys.
- Careful selection of materials of construction and plating systems.
- Heat treatment to remove absorbed hydrogen.

3. Hydrogen attack at high temperature

- Selection of material (for steels, use of low and high alloy Cr-Mo steels; selected Cu alloys; non-ferrous alloys).
- Limit temperature and partial pressure H_2 (using of the Nelson Curves).

Minimizing hydrogen content in steel could be obtained by good steel making practice e.g. vacuum melting and degassing techniques. Moist raw materials should not be used and enough time should be given for solidification of the molten metal so as to liberate hydrogen trapped due to decreasing solubility.

Blistering prevention includes:

- Cleanliness of alloys to preclude the presence of large internal surfaces. Shape of inclusions greatly influences the susceptibility. Elongated inclusions are dangerous and spherical shape is desirable. Such shapes can be achieved by rare earth addition during secondary refining of steel.
- Use of cleaning and processing technologies that minimize hydrogen absorption,
- Post process heating to cause hydrogen egress from the metal,
- Use of inhibitors to minimize corrosion reactions,
- Selection of alloys that show low tendency for hydrogen segregation at extraordinary sites (for example austenitic steels rather than ferritic or martensitic steels).

The approach to minimize HIC is to impede hydrogen entry into steel. This can be achieved by direct deposition of a solid on the surface so that hydrogen entry is lowered. In some cases corrosion products formed on the surface also act as barrier to hydrogen entry. Coating steel with Cd, Au, Ag, Pt, Cu, Al, austenitic steel or nitrides and oxides surface layers will lower hydrogen diffusion inside steel.

Providing hydrogen with surface traps is another alternative. Ion implantation of Ti has reduced hydrogen entry by providing atomic traps at the surface. Similarly an amorphous layers obtained by implanting phosphorus ion on steel has reduced the hydrogen permeation rate through composite material.

Elements such as As, Se, Te, S, P, Sn, Hg, Pb and Bi that promote hydrogen entry by inhibiting hydrogen recombination reaction should be strictly avoided in hydrogen ion-containing environments. These elements when present inside steel segregate to grain boundaries and should be avoided as much as possible.

To avoid HIC, HEC, HSC during welding, the amount of hydrogen entering the weld metal can be limited by the use of clean, low hydrogen consumables. Electrodes should be stored

at an appropriate temperature in ovens or used from freshly opened airtight containers. Cleanliness of weld preparation, welding wire and welding apparatus is also important. Paint, rust, grease, degassing agents can all be hydrogen sources. An additional approach to hydrogen control is to allow hydrogen removal by diffusion so that the levels are reduced to acceptable values by the time the weld has cooled. This is done by preheating which decreases the cooling rate and allows more time for the hydrogen to diffuse. Moisture and contamination are also burned off by this.

Using higher welding heat inputs also increases the weld thermal cycle time.

In steels with electrolytic coatings (zinc, cadmium) the diffusible hydrogen should be forced out during the heat treatment between 190 and 220°C because the effusion rate is far too low at room temperature (hydrogen diffusion ability in zinc layers is low) [21].

Chapter 5

Stress Corrosion Cracking

Stress Corrosion Cracking (SCC) is defined as the growth of cracks due to the simultaneous action of a stress (nominally static and tensile) and a reactive environment. For metals, “reactive” excludes gaseous hydrogen, cathodic polarization, and liquid metals but includes aqueous and non-aqueous electrolytes and reactive atmospheres (H_2O , I_2 , Cl_2).

Related phenomena occur in inorganic glasses and ceramics, especially in water, and are thought to be involved in major geological processes including earthquakes and mid ocean volcanism. Static stress does not exclude slow monotonic straining or low-amplitude cycling (“ripple loading”), which accelerate SCC in many metallic systems—for example, by promoting oxide film rupture at the crack tip. Stresses arise in practice from applied loads or from residual stress due to welding or inhomogeneous plastic deformation. Plasticity plays a key role in SCC of metals, in contrast to inorganic glasses and ceramics, which are brittle solids and crack via reaction of the corrodent with highly stressed bonds at an atomically sharp crack tip. Metal-induced fracture, formerly called liquid-metal embrittlement, remains a tantalizing phenomenon and there is no agreement on the mechanism or the relationship to SCC. Several authors have proposed universal models of SCC and corrosion fatigue or even universal models of environment-assisted fracture, encompassing aqueous, gaseous, and liquid-metal environments [16].

Characteristic features

Stress-corrosion cracking is a system property influenced by factors contributed by the metal and by the environment. The following features are characteristic:

Conjoint action: Cracking is caused by the synergistic combination of stress and a specific environmental agent, usually in aqueous solution. Separate or alternate application of stress and exposure to the agent is insufficient.

Stress: Constant stress intensity in a crack-opening mode, K1, K2 or K3 is sufficient. It may be applied externally or by internal strains imparted by fabrication, contraction after welding or mechanically-corrected mismatch.

Environment: Conditions for SCC are highly specific and for a given metal or alloy, cracking is induced only if one or another of particular species, the specific agents is present. General corrosion or the presence of other environmental species is insufficient.

Crack morphology: The cracks appear brittle with no deformation of adjacent metal, even if the mode of failure under stress alone is ductile.

Life-to-Failure: The life decreases with increasing stress and is the sum of two parts

- (a) An induction period which determines most of the life, e.g., weeks or years and
- (b) A rapid crack propagation period, typically hours or minutes.

Crack path: The crack path is a characteristic of particular metals or alloys. For some it is intergranular, i.e., along the grain boundaries between the metal crystals; for others it is transgranular, i.e., through the crystals, avoiding grain boundaries; for yet others it is indiscriminate.

Sensitivity to steel structure and composition

The relationships between the susceptibility to SCC and steel compositions, condition, and microstructures are complex, often known only empirically and sometimes not reproducible.

The cracks are transgranular and can exhibit multiple branching. The presence of some ferrite in nominally austenitic stainless steels can block the cracks suggesting that ferrite is more resistant to SCC. Worked austenitic steels do not have sufficient ferrite for the effect to have any practical value but castings of equivalent steels have non-equilibrium structures and can contain as much as 13% ferrite, persisting from an uncompleted peritectic reaction, which affords a useful degree of protection. For the same reason, duplex steels that are formulated to contain both austenite and ferrite whether cast or wrought are less susceptible than austenitic steels.

The influence of the composition of an austenitic stainless steel on its susceptibility to SCC is not well-defined. High nickel and chromium contents improve resistance to SCC but, judging from published information, the influences of other alloy components, including molybdenum and carbon, which are often components of austenitic stainless steels, do not seem to be reproducible, perhaps because of uncertainties in interactions between the components of the alloys [16].

Some specific environments that can cause SCC of certain metals are listed in Table 4.

Material	Environment
Aluminum alloys	NaCl, H ₂ O ₂ solutions NaCl solutions Seawater Air , Water vapor
Copper alloys	Ammonia vapors and solutions Amines Water, water vapor
Gold alloys	FeCl ₃ solutions Acetic acid salts solutions
Inconel	Caustic soda solutions
Lead	Lead acetate solutions
Magnesium alloys	NaCl-K ₂ CrO ₄ solutions Rural and coastal atmospheres Seawater Distilled water
Monel	Fused caustic soda Hydrofluoric acid Hydrofluorosilicic acid
Nickel	Fused caustic soda

Ordinary steels	NaOH solutions NaOH-Na ₂ SiO ₂ solutions Calcium, ammonium, and sodium nitrate solutions Mixed acids (H ₂ SO ₄ -HNO ₃) HCN solutions Acidic H ₂ S solutions Seawater Molten Na-Pb alloys
Stainless steels	Acid chloride solutions (e.g. MgCl ₂ and BaCl ₂) NaCl-H ₂ O ₂ solutions Seawater H ₂ S NaOH-H ₂ O solutions Condensing steam from chloride waters
Titanium alloys	Red fuming nitric acid, seawater, N ₂ O ₄ , methanol HCl

Table 4: Environments that may cause stress corrosion cracking of materials [22].

<u>CHAPTER 5</u>	CORROSION CASE HISTORY	<u><i>STRESS CORROSION CRACKING</i></u>
Phenomena: Gas Leakage	Illustration (Macro): Choke Valve	Phenomenon: Cracking
Illustration (Micro):-	Environment: X-Tree	Size: 2"
Material: SS410	Time in service: 4 years	Fluid: Sour Gas
Operating Pressure: 4800 Psig	Coating Type:-	Orientation of Specimen: 0°
		
<p>History:</p> <p>The susceptibility of these steels to stress corrosion cracking is determined by imposing stresses on test specimens and determining the time elapsed for cracks to propagate in a given environment. The failure time increases as the severity of imposed stress decreases; thus, stress values should be imposed until such time when no failure occurs, thereby determining the maximum stress value that can be applied to prevent crack propagation by SCC .</p>		
<p>Solution:</p> <p>The first line of defence in controlling stress corrosion cracking is to be aware of the possibility at the design and construction stages.</p>		

Phenomena: Fatigue fracture

Illustration (Macro): Hydraulic gate valve

Phenomenon: Corrosion Fatigue

Illustration (Micro): stem

Environment: X-Tree

Size:-

Material: SS 15-5PH

Time in service: 6 years

Fluid: Sour Gas

Operating Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 90°



History:

Fatigue was induced from the sharp corner of the keyway.

Solution:

- Reducing of stress accumulation by creating a curvature in the pitch roots
- Removing of microstructure inclusions
- Using of alloys with high resistance (Incoloy 925 (UNS N09925), Custom 450 (UNS S45000), (UNS 41000)410, 17-4PH (UNS S17400)
Change to heat treated AISI 4340 (S43400) with radius in keyway.

CHAPTER 5

CORROSION
CASE HISTORY

STRESS CORROSION
CRACKING

Phenomena: Fracture

Illustration (Macro): Well line tubing

Phenomenon: Longitudinal cracking

Illustration (Micro): Traveling Joint

Environment: well head equipment in depth of 3376 m

Size: 5 ½"

Material: DIN 1.1133 (20Mn5)

Time in service: 4 years

Fluid: Sour Gas

Operating Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

Presences of sour water with chloride make a longitudinal crack along the tube. The main reason is the low resistance of selected material against of HIC and SCC.

Solution:

- Using alloys with fine grains and lower inclusions and also with high resistance ability against chloride, HIC and SCC.

Phenomena: Cracking

Illustration (Macro): Grit trap

Phenomenon: Sulphide Stress Cracking

Illustration (Micro): Cap

Environment: Flow line

Size: 6"

Material: SS 316

Time in service: 1 year

Fluid: Sour Gas

Pressure: 4800 Psig

Coating Type:-

Orientation of Specimen: 90 °



History:

As observed in the photo, stress corrosion cracking (SCC) takes place within the material, where the cracks propagate through the structure. The crack tend to propagate in a direction that is perpendicular to the direction of applied stress(attacking the sands).

Solution:

- Choose a material that is resistant to SCC.
- Use surface treatments (shot peening, laser treatments) which increase the surface resistance to SCC.
- Any barrier coatings will deter SCC as long as it remains intact.
- Reduce exposure of end grains (i.e. end grains can act as initiation sites for cracking because of preferential corrosion and/or a local stress concentration).

Phenomena: Fracture

Illustration (Macro): Safety valve

Phenomenon: Sulphide Stress
Cracking

Illustration (Micro): Spring

Environment: Flow Line

Size: -

Material: SS 316

Time in service: 3 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 90°

**History:**

Stress-corrosion cracking occurred because of a corrosive sour gas (H_2S) and sufficient stresses coexist. This spring was used in a safety valve. This fatigue (above figure) occurred due to residual internal stress in the metal or external applied stress. Residual stresses were produced by deformation during fabrication, by unequal cooling from high temperature and by internal structural arrangements involving volume change.

Solution:

- By choosing a material that is not susceptible to SCC in the service environment, and by processing and fabricating it correctly, subsequent SCC problems can be avoided. Unfortunately, it is not always quite that simple.
- As one of the requirements for stress corrosion cracking is the presence of stress in the components, one method of control is to eliminate that stress, or at least reduce it below the threshold stress for SCC. This is not usually feasible for working stresses (the stress that the component is intended to support), but it may be possible where the stress causing cracking is a residual stress introduced during welding or forming.
- Residual stresses can be relieved by stress-relief annealing, and this is widely used for carbon steels. These have the advantage of a relatively high threshold stress for most environments, consequently it is relatively easy to reduce the residual stresses to a low enough level. In contrast austenitic stainless steels have a very low threshold stress for chloride SCC. This, combined with the high annealing temperatures that are necessary to avoid other problems, such as sensitization and sigma phase embrittlement, means that stress relief is rarely successful as a method of controlling SCC for this system.

Preventing comments

Tensile stresses in a component are the result of externally applied loads experienced during storage, transportation and service, and residual stresses introduced during manufacture and assembly. Whereas tensile stresses associated with external loads can be determined during design with a certain degree of confidence, tensile residual stresses introduced during manufacture and assembly are more difficult to predict and therefore often underestimated or neglected (residual stresses can often approach the material yield strength in weldments and bolted joints). These residual stresses are generally sustained stresses. For this reason they can promote SCC and should always be considered when assessing the risk of failure by stress-corrosion cracking of a component.

Manufacturing and detail design can reduce the risk of SCC failures by reducing tensile stresses acting in the short-transverse direction of the material and reducing assembly stresses resulting from mismatch or excessive clearance between elements in mechanical joints.

SCC is influenced by several factors such as stress level, type of corrosive environment, temperature, alloy chemical composition, temper, grain structure and mechanical properties. Deformations such as buckling and twisting of material in the vicinity of weldments often indicate the presence of high residual stresses. These may approach the yield strength of the alloy and unless suitably relieved by means of stretching and/or heat treatment, such stresses can promote failures by SCC. Surface protection treatments against corrosion such as chemical conversion coating are not particularly effective in the prevention of SCC.

SCC is a time dependent phenomenon. Time-to-failure in a SCC susceptible alloy subjected to constant tensile stress decreases rapidly with increasing stress level. A threshold stress value is defined as the maximum stress that the material can sustain in a particular environment without SCC failure to occur [23].

Chapter 6

Corrosion under Insulation

Insulation is applied to vessels and piping as a means of conserving heat or of providing personnel protection from hot surfaces. As a result, the selection of a particular insulating material is normally based on installed cost versus energy saved. However, there are other costs associated with insulation that are generally overlooked, namely the cost of corrosion and maintenance corrosion that takes place under the insulation can be caused by the insulation itself or by improper application. If after a period it is necessary to remove sections of insulation to make repairs on the equipment, these costs and the cost of repairing the insulation should be considered during the selection process.

Thermal insulation, when exposed to water, can hold a reservoir of available moisture which together with the permeability of air causes severe attack, up to 200 to 300 mpy. This is particularly true on warm steel surfaces. Severe corrosion may occur on cold surfaces where structural members about the insulated vessel or pipe, permitting rime ice to form. Depending upon the specific containment, insulation can cause stress corrosion cracking of high-strength copper alloys and external stress corrosion cracking of type 300 series stainless steels. Chlorides or alkaline containments will rapidly attack aluminum. The use of an appropriate coating system, such as a catalyzed epoxy-phenolic and modified silicone, will help to prevent such corrosion in the event of ingress of water. Zinc and chloride-free coatings should be used for stainless steels.

Types of corrosion under insulation

There are three types of corrosion that can take place under insulation:


1. Alkaline or acidic corrosion
2. Chloride corrosion
3. Galvanic corrosion

Alkaline or acidic corrosion takes place as a result of either acid or alkali being present in contact with moisture in the insulating material. When these materials are applied to hot surfaces at temperatures above 250°F (121°C), the water is driven off, but it may condense at the edge of the insulation, dissolving any alkaline or acidic materials present. This results in corrosion of aluminum with certain alkaline waters. Some insulating cements, before drying, contain alkaline chemicals and water. During the drying operation these alkaline chemicals will attack such metals as stainless steel, copper, brass and aluminum. If the vessel being insulated is constructed of one of these metals, it may be subject to corrosion. Under normal circumstances steel would not be affected during the time required for the cement to dry.

Foam insulations containing fire-retardant chemicals, such as brominated or chlorinated compounds, can produce acidic solutions. This has been found to be true with polyurethane

and phenolic foams. Steps can be taken to prevent this type of corrosion. When external

<u>CHAPTER 6</u>	CORROSION CASE HISTORY	<u>CORROSION UNDER INSULATION</u>
Phenomena: Thickness Thinning	Illustration (Macro): Elbow 90°	Phenomenon: Severe general pitting
Illustration (Micro):-	Environment: Underground pipeline	Size: 6"
Material: A 234 WPB	Time in service: 22 years	Fluid: Sour Gas
Operating Pressure: 1440 Psig	Coating: Calcium silicate	Orientation of Specimen: 0°



History:

Despite of using a good cathodic protection system, a severe pitting corrosion occurs under calcium silicate coatings. Liquid accumulations under coating intensify corrosion process, therefore galvanic cell created and initiate corrosion process and continue. Finally thickness thinning observed.

Solution:

- Replacing of calcium silicate coatings with appropriate coatings.

Phenomena: Explosion**Illustration (Macro): Elbow 90°****Phenomenon: Severe Pitting
Corrosion****Illustration (Micro): Transition
pipe line****Environment: Under ground****Size: 6"****Material: A860-WPHY42****Time in service: 2 years****Fluid: Sour Gas****Operating Pressure: 1440 Psig****Coating Type: CaSiO₃****Orientation of Specimen: 0°****History:**

CaSiO₃ coatings as insulation coatings had been carried out on the mentioned elbow. This coating absorbs the corrosive electrolyte and despite of using of appropriate cathodic protection system, due to corrosive electrolyte accumulation near the welding area galvanics cell create and severe corrosion process starts. Finally corrosion under insulation occurs in shape of deep pits.

Solution:

- Removing of CaSiO₃ Coatings.

Phenomena: Rupture**Illustration (Macro): Elbow 90°****Phenomenon: Severe Pitting
Corrosion****Illustration (Micro): Transition
Flow Line****Environment: Under Ground
Flow Line****Size: 6"****Material: A860-WPHY 42****Time in service: 20 years****Fluid: Sour Gas****Operating Pressure: 1440 Psig****Coating Type:-****Orientation of Specimen: 90°****History:**

Despite of using a good cathodic protection system, severe pitting observed due to liquid accumulation under insulation (calcium silicate). Therefore several galvanic cells created and initiate corrosion process and continue and finally thickness thinning cause an explosion.

Solution:

- Replacing of calcium silicate coatings with appropriate coatings.

CHAPTER 6

CORROSION
CASE HISTORY

CORROSION UNDER
COATING

Phenomena: Thickness Thinning

Illustration (Macro): Pipeline

Phenomenon: General corrosion
with pitting

Illustration (Micro): -

Environment: Under Ground

Size: 16"

Material: API 5L-X42

Time in service: 20 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type: Calcium silicate

Orientation of Specimen: 0°



History:

The coatings which used in welding parts were thermal coating of CaSiO_3 . This coating absorbs the corrosive electrolyte. Despite of using of appropriate cathodic protection system, because of corrosive electrolyte accumulation near the welding area. A galvanic cell creates and severe corrosion process starts. Finally corrosion under insulation occurs in shape of deep pits.

Solution:

- Removing of calcium silicate coating
- Adequate inspection according to coating standards.

Preventing comments

Some of the newer techniques include the following:

Thermal Spray Aluminum (TSA): The U.S. Navy has demonstrated that using TSA

has substantially reduced the cost of its corrosion-control efforts aboard ships. To achieve a lifetime of more than 25 years, corrosion experts recommend TSA for carbon steel. It has been documented that one TSA-coated vessel has been operating with wet insulation in CUI conditions for more than 50 years with no maintenance or recoating throughout its lifetime. TSA also works well in conditions too severe for organic coatings, such as temperature cycling above and below 300°F (149°C) for more reliable, maintenance-free service. TSA coatings can be used up to a service temperature of 1,000°F (537°C). It protects equipment by acting as a barrier and serves as a sacrificial anode, protecting the substrate at the sites of any chips or breaks in the coating.

Wire flame spraying: This technique is the oldest of the thermal spraying processes and also is referred to as combustion wire or oxyfuel wire spray process and it is useful for applying relatively inexpensive coatings. A wide variety of materials can be sprayed by this process, and the vast majority of components are sprayed manually.

Twin wire electric arc spraying: In electric arc wire spray, the weight of coating that can be deposited per unit of time is a function of the electrical power (amperage) of the system, and the density and melting point of the wire. Push, pull, or push/pull mechanisms can be used to feed the wire at a constant rate, depending on the columnar strength of the wire.

This process uses two metallic wires, usually of the same composition, as the coating feedstock. The two wires are electrically charged with opposing polarity and are fed into the arc gun at matched, controlled speeds. When the wires are brought together at the contact point, the opposing charges create enough heat to continuously melt the tips of the wires. Compressed air is used to atomize the now-molten material and accelerate it onto the work piece surface to form the coating.

Aluminum foil wrapping: Aluminum foil wrapping of austenitic stainless steel has been used successfully for more than 30 years by chemical companies in Europe to prevent ESCC. (This technique has not been widely accepted in the United States.) The aluminum foil provides a moisture barrier and electrochemical protection by preferentially undergoing corrosion and maintaining a safe potential for stainless steel. The system relies on good weatherproofing and the prevention of immersion conditions. It can be applied by the insulation contractor, takes less time to apply than a coating, and requires minimal substrate preparation.

Duplex stainless steels: To eliminate ESCC, higher nickel, chromium and molybdenum containing alloys (super stainless steels) and lower nickel/higher chromium duplex alloys can be used. These alloys are more resistant to SCC and resistant to ESCC under insulation. Although some of the duplex alloys are slightly higher in cost than the 300 series austenitic, analysis shows that the duplex stainless steel alloys (especially the lean duplexes) may offer a low life-cycle cost alternative.

Wire personnel protection cages: In many instances, thermal insulation is used for personnel protection from hot surfaces. The unnecessary use of thermal insulation creates a location for potential corrosion. In these cases, wire “standoff” cages should be used instead. These cages are simple and inexpensive, and they eliminate CUI concerns [25].

Nanotechnology solution for CUI: Finally, nanotechnology offers a way to remove for inspection personnel to inspect for corrosion more regularly and without removal of the insulation. This lowers both labor costs and costs of pipeline an equipment replacement due to CUI. Nanotechnology coatings offer a single product solution for corrosion resistance and insulation for pipelines, tanks and other plant equipment, which is easily applied, and maintains its effectiveness over time.

These have four main characteristics that combat problems with CUI:

1. Low thermal conductivity (making it an insulator)
2. Corrosion resistance
3. Resistance to moisture
4. Clear finish that allows visual inspection without insulation removal [26].

Chapter 7

DisBonded Coatings

Mode of failure

Air permeation: Polymeric pipeline coatings are permeable because of the presence of pores at the molecular level. Gas can permeate through the pores. When gases permeate a coating that is well bonded to steel, the pressure within the coating increases. At high levels of permeation, the build-up of pressure may be reduced by the liberation of gases, causing disbondment of the coating. At low levels of permeation, the state of equilibrium is reached without any chemical or physical changes to the coating.

Water permeation: In addition to gases, water and salts can also penetrate the coating. Permeation is further facilitated by osmosis and electroosmosis. When a semipermeable membrane (e.g., pipeline coating) separates a solution of different concentrations, the water permeates from the concentrated solution side to the dilute solution side so that the concentrations at both sides of the membrane become the same. This process is called osmosis. The presence of salts on the contaminated steel surface results in the development of the osmosis process. If osmosis is facilitated by the electrical current flow caused by the application of Cathodic Protection (CP), it is called electroosmosis.

Loss of adhesion: Adhesion is a measure of the degree of attachment between the coating and the pipeline steel with which it is in contact. The adhesion is a force that keeps the coating on the steel surface. Adhesion may be caused by chemical, physical and mechanical interactions. When these interactions are diminished, the coating loses its adhesion.

Loss of cohesion: The cohesive strength is the bonding within the coating itself that holds the coating together as an entity. A coating with great cohesion will break the adhesive bond with the surface and then peel off the surface to form a free-standing coating (Figure 8a). On the other hand, if the cohesive strength is less than the adhesive strength, the coating will break within itself, leaving part of the coating on the surface of it (Figure 8b). Because the pipe surface is protected by the remainder of the coating, the damage is not as severe as that caused by adhesion failure.

Blistering: The swelling of coatings from water absorption causes a lateral distortion of the film with respect to the steel. Stresses at the coating/steel interface arising from the distortion produce a loss of adhesion, causing a blister. If CP completely penetrates through the blistered coating, then the pH of the solution will be in the alkaline range (>7). Under blistered coatings, a pH as high as 12 has been observed.

Disbondment and passage of cathodic protection current

Degradation of adhesion by CP is known as cathodic disbondment. Factors including pH, cathodic potential, the stability of the interfacial oxide, the substrate surface roughness, defect geometry, coating formulations, cyclic wetting and drying, and water uptake

contribute to cathodic disbondment. As in the case of a blistered coating, if CP completely penetrates the disbonded coating, the pH of the solution below the disbonded coating will be in the alkaline range. The increase in pH comes from the consumption of hydrogen ions and the generation of hydroxyl ions. Maintaining a high pH environment helps to protect the steel beneath a disbonded coating by passivating the pipeline steel. The interruption or removal of the CP system may cause a decrease in pH and cause the potentials to shift to more positive values. At more positive potentials, corrosion may occur.

Coating disbondment leads to the formation of crevices. Sizes of disbondments depend on the coating, the species in the environment, the morphology of the disbondment, and the level of CP. Where access to the inside of a crevice is restricted, a significantly different chemistry may be present compared to the chemistry in the groundwater.

Where the solution is trapped and there is little or no exchange with fresh solution, the corrosion rate of steel will decrease rapidly and remain at low values.

Where an exchange of solution (the flow of water between the coating and the pipe) can occur, a frequent or continual generation of alkalinity by external polarization is required to control corrosion.

In high-conductivity solutions, CP can be effective within a crevice. Clean crevices with large openings are easier to polarize than those containing mill scale or corrosion products. The pH of the solution inside the crevice is alkaline, whereas the bulk solution just outside the crevice remains neutral.

Disbondment and prevention of the passage of cathodic protection

Generally, if the solution resistance is high, there is a large ohmic drop and essentially no flow of current into the disbonded region. If CP does not penetrate, and then corrosion occurs at the disbonded region even when the pipe-to-soil potential at the ground surface meets the -0.85V or other criterion.

Increase in cathodic protection current

Even on a microscopic level, polymeric coatings exhibit pores or holidays.

The origin of holidays can be traced to the mode of crystal formation/growth. During construction, crews are careful not to damage the protective coating. In spite of these precautions, sometimes coatings are removed and/or damaged.

These areas act as potential locations where disbondments may initiate. External coatings and CP work synergistically to mitigate the corrosion of pipelines.

It is difficult to cathodically protect a bare pipeline because the magnitude of the current required for protection is high. A good-quality coating can decrease the current required by a factor of 1,000 or more. As the coating deteriorates and/or more and more holidays are formed, the CP current demand increases, until it is economically not feasible to protect the pipeline with a deteriorating coating.

Six coating systems were evaluated over a period of 25 years: Fusion-Bonded Epoxy (FBE), coal-tar enamel, asphalt enamel, polyethylene tape, asphalt mastic and urethane. Several locations exhibited pitting corrosion. These locations were distributed through all four coating types and were generally located in areas where the coating conditions were poor. Many of the defects were in areas where the CP was initially considered to be adequate, indicating that, where coatings were in poor condition, CP was not completely effective.

Ranking of coating failure modes

Although any chemical, physical, or electrochemical changes may be considered as a

coating failure, not all changes affect the ability of coatings to protect the pipeline. In an ideal situation, polymeric coating protects the pipeline and, when it fails, the CP acts as the backup. Only after both defense mechanisms fail would the pipeline become susceptible to corrosion.

The worst-case scenario of coating failure is the one in which the coating no longer protects the pipeline, and, in addition, the coating prevents the CP from protecting the pipeline. This type of failure mode is primary in terms of the impact of the failure on the protection of the pipe.

The presence of holidays is the second most common cause of failure because the CP current increases as the holiday size and number increase. The alkaline pH created by the CP can easily become diffused, and hence, the CP should be applied continuously.

The formation of disbondment behind a coating that passes CP presents the third ranking. In this case the coating has failed, but CP can act as the backup. Because of the diffusion limitation of the hydroxide (OH^-) ions, the amount of CP required is smaller.

The formation of blisters is the fourth ranked cause of coating failure. This failure is associated with the penetration of water, so that CP can prevent corrosion at this location. This case is better than that with disbonded coating protected with CP because CP reaches the steel surface readily and uniformly. Loss of adhesion makes the coating unable to perform its primary function (i.e., to cover the steel surface). This is the fifth-ranked mode of failure. Loss of cohesion is the sixth because at least part of the coating still covers (and hence protects) the steel surface.

Water permeation through the coating is the seventh-ranked failure mode. This mode of failure establishes electrochemical cells, facilitating conditions for corrosion to occur.

The permeation of gases may break certain chemical bonds, but may have limited effect on the overall performance of the coating. This is the eighth-ranked failure mode [27].

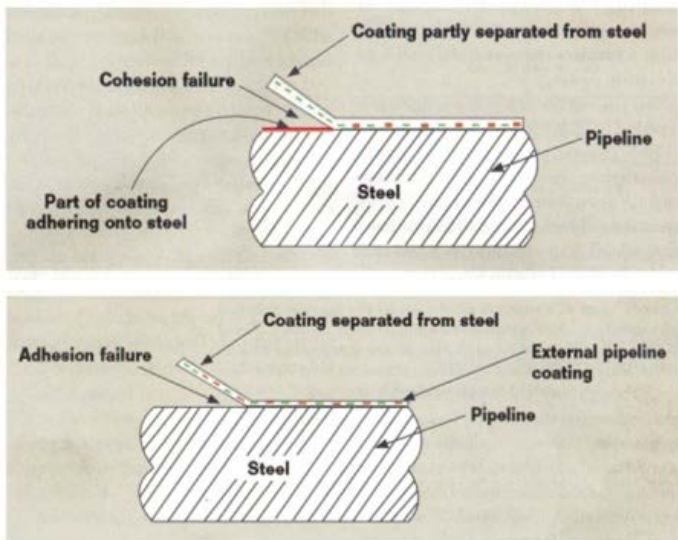


Figure 8: a) Adhesion failure, b) Cohesive coating failure [27].

Phenomena: Severe corrosion

Illustration (Macro): Flow line

Phenomenon: Corrosion under Coating

Illustration (Micro): Line pipe

Environment: Underground pipe line

Size: 12"

Material: API 5L X-42

Time in service: 20 years

Fluid: Sweet Gas

Operating Pressure: 1200 Psig

Coating Type: Coltar epoxy

Orientation of Specimen: 0°



History:

The mentioned flow line carried out for 20 years, but unfortunately the protective coating could not act as a good barrier for metal surface. Therefore corrosive media diffuse under it and corrosion under coating occurred.

Solution:

- Use coating of suitable heat resistance, augmented by cathodic protection.

Phenomena: Severe corrosion

**Illustration (Macro): Transition
pipe line**

**Phenomenon: General corrosion
on coating failure**

Illustration (Micro):-

**Environment: underground pipe
line**

Size: 14"

Material: API 5L-X42

Time in service: 29 years

Fluid: Sweet Gas

Pressure: 1440 Psig

Coating Type: Epoxy

Orientation of Specimen: 0°

Witness:



History:

The mentioned flow line carried out for 29 years, but unfortunately the protective coating could not act as a good barrier for metal surface especially near the weld sections. Therefore corrosive media diffuse under it and corrosion under coating occurred.

Solution:

- It is recommended to use a coating with better protective ability.

CHAPTER 7

**CORROSION
CASE HISTORY**

CORROSION UNDER
COATING

Phenomena: Thickness Thinning

Illustration (Macro): Transition pipe line

Phenomenon: Pitting Corrosion

Illustration (Micro):-

Environment: Underground flow line

Size: 8"

Material: API 5L-X42

Time in service: 9 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type: Bitosil

Orientation of Specimen: 0°



History:

The mentioned pipeline had been used as transition pipeline at underground environment (under soil). After coating disbonding and diffusing of corrosive electrolyte the corrosion process occurs. This process causes thickness thinning and if it is not indicated, maybe an explosion will occur.

Solution:

- Using of valid techniques to detect the disbonded area and thin parts of a pipeline.
- Carried out an appropriate coating with high protection ability.

Preventing comments

Because of differing environmental conditions (e.g., soil moisture, microflora, nutrients) in both field surveys and laboratory experiments, it is extremely difficult to interpret comparisons of coating performance. Soil stress or tenting along irregularities on the pipe surface, especially at long seam or girth welds, can create gaps between the tape and the pipe surface that fill with ground water and introduce microorganisms that create corrosion cells under the disbonded coating. Tenting is most prevalent in wet high clay soils, on unstable, geologically active slopes and downstream compressor stations. High service temperatures also promote disbonding. Not all coating materials are affected by soil bacteria under all conditions. Coatings derived from both coal (tars) and petroleum (asphalts) passes some exposure tests and fails others. Materials which by themselves show resistance to attack by microorganisms fail when combined or reinforced with other materials.

Peabody (1967) reported that coal tars, coal tar epoxies, and coal tar enamels were immune to disbonding because of activities of microorganisms. Early coatings based on asphalt were subject to oxidation and loss of low-molecular weight components through biodegradation and biodeterioration, resulting in permeable, embrittled coatings (Jack et al., 1996). Pendrys (1989) demonstrated that with time asphalt could be degraded by microorganisms selected from soil. Harris (1960) demonstrated that bacteria found commonly in pipeline soils can degrade asphalt, tape adhesives, kraft paper (expendable once line is in place), and binders and fillers used in felt pipeline wrappers. The next generation coatings were based on polyolefin tapes made of Polyvinyl Chloride (PVC) or Polyethylene (PE). The PVC tape was unstable in service. Plasticizers constitute up to 50% of a PVC product and can be effectively lost through biodeterioration and water dissolution. Tape coatings rely on adhesives to attach the polyolefin layer to the primed steel surface.

Jack et al., (1996) demonstrated that certain coatings disbonded more readily after being exposed to soils containing SRB and APB. PE coating damage proceeded linearly with time. PE tape coatings supported higher bacterial counts than extruded PE or Fusion-Bonded Epoxy (FBE), presumably because of the presence of biodegradable adhesive/primer components in the paint system. Susceptibility to disbonding increased in the order: FBE, extruded PE, and PE tape. Two types of coating damage were reported: damage due to water leaching and permeation, which affect intact coatings and coating around holidays. FBE coatings were damaged with increased susceptibility to cathodic disbondment at existing holidays.

The most prevalent mechanism for the observed corrosion in a study reported by Jack et al., (1996) was formation of a galvanic couple between microbiologically produced iron sulfides and steel. The couple is normally short-lived because the iron sulfide matrix becomes saturated with electrons derived from the corrosion process. In the presence of SRB, however, the corrosion process is perpetuated because SRB can remove electrons in the corrosion process from the iron sulfide surface. This process may involve formation of cathodic hydrogen on the iron sulfide or direct transfer of electrons from the iron sulfide matrix to redox proteins in the bacterial cell wall. Corrosion rates associated with this mechanism were proportional to the amount of iron sulfide in the corrosion cell [28].

Chapter 8

Under Deposition Corrosion

Under-deposit Corrosion: A corrosion deposit occurring under a scale or bacterial deposition and thus not treatable by corrosion inhibitors that are not designed for the purpose [29].

Corrosion under deposits due to the differential aeration cell may cause serious problems. The deposits which settle are mostly weed, stick, stones, barnacle, mussels, etc.

In the design stage, pipeline sizes can be adjusted to prevent slug flow at the anticipated liquid and gas flow rates. If the anticipated problem is corrosion under deposits in the bottom of the pipeline, the pipe size can be adjusted to eliminate stratified flow and keep the deposits suspended in the fluid.

When the fluid velocity in petroleum pipelines is insufficient, solids including sand, corrosion products and non-corrosion products will be deposited on metal surface, triggering localized pitting corrosion.

Owing to the inherent difficulty to detect and design against, the pitting process is extremely insidious. Criaud and Fouillac stated that the scale formed in the wells was FeS corrosion product due to reaction of dissolved sulfides with steel rather than a FeS mineral deposit from the produced brine. Martin and Investigations found that the presence of suspended FeS increases the corrosion rate because of an increase in the cathodic reaction through hydrogen adsorption by the suspended FeS particles. Furthermore sulfide films increase corrosion rates even when present in minute amounts [30].

To detect of this type of corrosion and estimate their service life, various methods can be used on the basis of some essential factors. In this field corrosion risk analysis results should be carried out to have some useful assessments. Based on the final results, different strategies can be achieved [31-33].

Phenomena: Thickness Thinning

**Illustration (Macro):
Accumulator**

**Phenomenon: Pits beneath
deposits**

**Illustration (Micro): Inside pipe
wall**

Environment: Gathering Part

Size: 20"

Material: API 5L-X42

Time in service: 24 years

Fluid: Sour Gas

Operating Pressure: 1440 Psig

Coating Type:-

Orientation of Specimen: 0°



History:

The deposition of impurities, as debris causes the formation of differential aeration cells, and allows the absorption of moisture from the air which leads to corrosion. Also presence of H₂O, H₂S, CO₂ accentuates the corrosion process. Furthermore the accumulation corrosion products prevent of contacting of corrosion inhibitors to metal surface and the protection process fails. This process results as thickness thinning which can be detected by Phased Array method.

Solution:

- Prevention of waste material accumulation in the bottom side. It can be done by using of suitable slope.

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