

Asset Integrity Management Handbook



Dr. Peter McClean Millar

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Author's Notes

Dedicated to my wife, Stephanie

This book came about because my son, who had just started his MSc in Offshore Engineering at Cranfield University, said to me that since I supposedly knew a fair bit about Asset Integrity Management, I should write a book on it. As I'd previously written several books on diving and dive watches, I thought; "hey, now that's not a bad idea."

What you have here is a collection of information dealing with what I consider to be the most important aspects of Asset Integrity Management. Some of it is based on papers and articles I have written, but considerably more is unashamedly "blagged" from many other sources that I consider to be far more knowledgeable than me on the subject matter.

It really started out as an attempt to put "old heads on young shoulders" and grew from that. I hope that you find it educational, enlightening and thought provoking and that it helps you understand Asset Integrity Management better.

I would like to acknowledge the help of a number of people who gave me advice, information and guidance in the production of this book. Thanks guys.

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It is the express desire of the author that this book be freely available and never sold for profit. If it can be used in any way to help make the Oil Industry a safer place to work then all who have either contributed to the information herein or the use of it have done something worthwhile and should be proud of that.

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Asset Integrity Management

Introduction

This book arose from a series of papers and procedures I put together when refining the Asset Integrity Management system for an aging offshore oil field infrastructure. The platforms, pipelines and onshore facilities were in excess of forty years old and needed some extensive refurbishment and a new Inspection and Integrity regime put in place. Many of the problems I came across were typical of those encountered every day in the Oil and Gas Industry and I thought it might be worthwhile to try to gather the data on degradation modes and Asset Integrity Management principles in one place. The information gathered here is not complete. No book on Integrity Management could ever be, however, it is hoped that it encompasses the major problems and methodologies in use today.

The Oil and Gas Industry is full of challenges which can consume large amounts of time, money and resources. A better understanding of the problems associated with trying to operate a successful Asset Integrity Management system can go a long way to making the whole industry safer and environmentally friendlier.



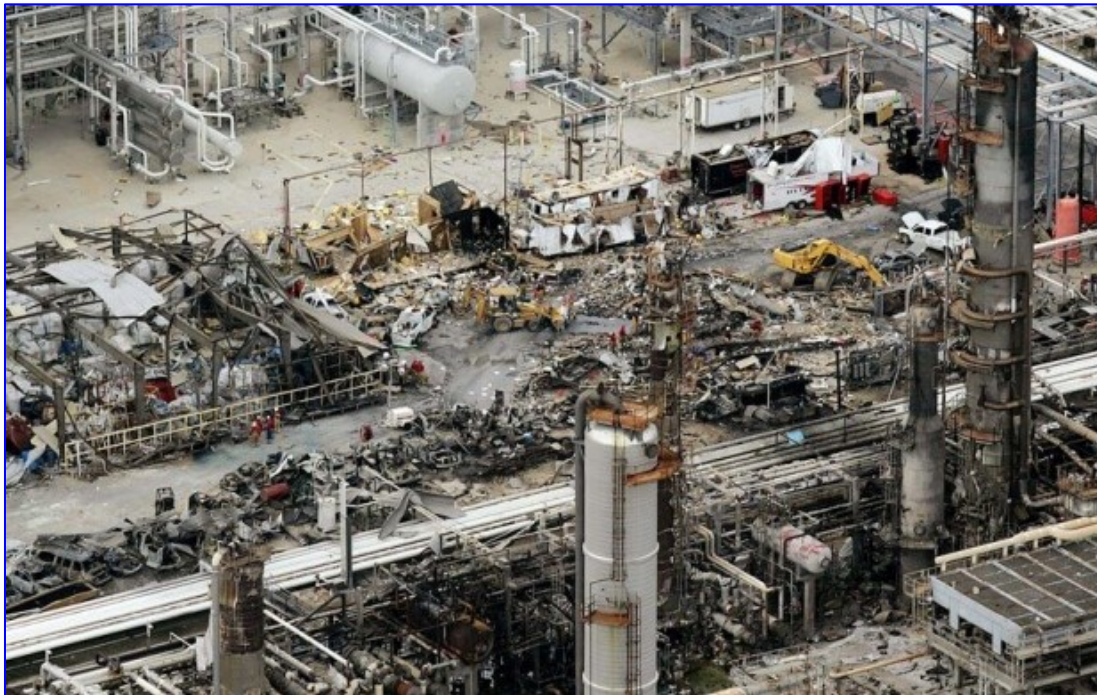
What is Asset Integrity Management?

"Those who cannot remember the past are condemned to repeat it" – George Santayana

Before trying to answer the question it is probably worthwhile to stop for a moment and look at some pictures which show what happens when proper Asset Integrity Management systems are not in place or when those that are, fail. The images show the absolute devastation that can occur when we get it wrong. What they don't show is the immeasurable emotional cost to families from the loss of life and the financial impact measured in billions of dollars for the damage to the environment and loss of production. Unfortunately as an industry we seem to just stagger from disaster to disaster without seeming to learn anything. In reality, it doesn't matter how we define what Asset Integrity Management is. We have to be aware that it has to be a living, breathing system that changes over the life of an asset and its ultimate aim is to allow people to go home safely to their families.



Piper Alpha - North Sea – 1988



Texas City Refinery – Texas - 2005



Deep Water Horizon / Macondo – Gulf of Mexico – 2010



Amuay Refinery - Venezuela - 2012

There are a number of definitions for Asset Integrity and Asset Integrity Management; most say almost the same thing. The following are from the UK Health and Safety Executive.

Asset Integrity can be defined as the ability of an asset to perform its required function effectively and efficiently whilst protecting health, safety and the environment.

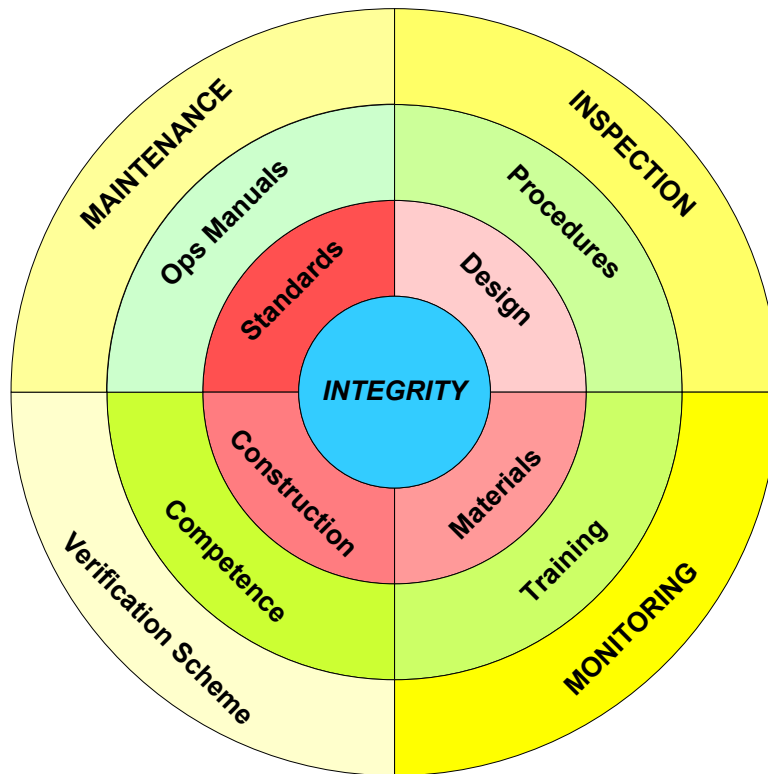
Asset Integrity Management is the means of ensuring that the people, systems, processes and resources that deliver integrity are in place, in use and will perform when required over the whole lifecycle of the asset.

Although the risk of a major incident can never be reduced to zero, significant reductions in the likelihood of occurrence and consequence can be achieved by utilizing a systematic delivery and assurance process which enhances the asset's overall reliability and performance.

Asset Integrity Management can further be described as the continuous assessment process applied throughout design, construction, installation and operations to assure that the facilities are and remain to be fit for purpose. In this context integrity is defined as the prevention of the loss of containment of a fluid or energy from the facilities. The integrity management process covers the equipment containing the fluid, the structures that support the equipment, and those other systems that prevent, detect, control or mitigate, against a major accident hazard. A loss of integrity (containment) could have an adverse impact on the safety of personnel, on the safety of the asset / facilities, on the environment or on production and revenue. The aim of the asset integrity management process is to provide a framework for the following:

- Compliance with company standards, regulatory and legislative requirements
- Assurance of technical integrity by the application of risk based or risk informed engineering principles and techniques
- Delivery of the required safety, environmental and operational performance
- Retention of the License to Operate
- Optimization of the activities and the resources required to operate the facilities whilst maintaining system integrity
- Assurance of the facilities' fitness for purpose

Some of the contributing factors to the assurance of current and continued asset integrity are represented in the following figure.

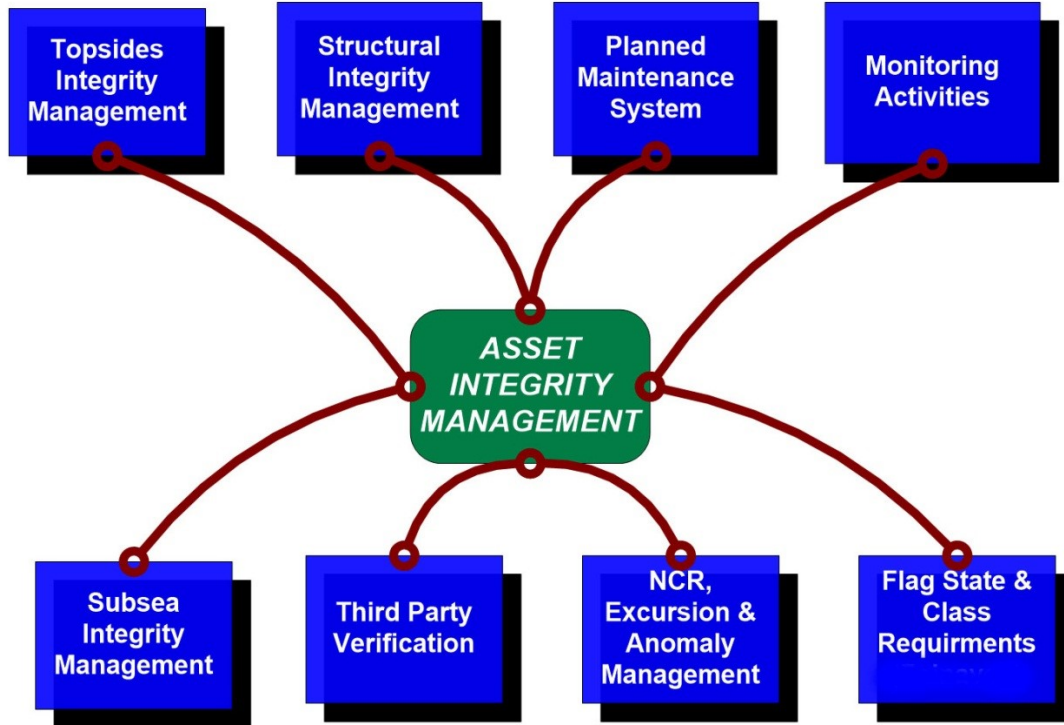


Contributors to Asset Integrity

There are a number of processes and activities, which are carried out by various bodies with the aim of ensuring that the overall integrity of the asset is maintained. Included in these activities are:

- Design and construction process
- Planned maintenance process
- Fluids and chemical monitoring process
- Topsides integrity management process
- Subsea integrity management process
- Verification process
- Class/flag surveys for non-fixed offshore assets (FPSO, Jackups, Semi Subs etc.)

These various inputs to the overall integrity management are summarized in the following



Inputs to Overall Asset Integrity Management

One of the main drivers for the integrity management activities is the requirement for compliance with the relevant national legislation. In the UK, for example, the offshore legislation includes

- The Safety Case Regulations
- Pipeline Safety Regulations
- Offshore Installations and Wells (Design & Construction, etc.) Regulations
- Prevention of Fire and Explosion and Emergency Response Regulations

This legislation requires that a policy be in place for the prevention of major accidents. In addition there is a further requirement to comply with the Operator's HSE Policy which will include such criteria as:

1. Leadership and Accountability
2. Risk Assessment and Management
3. People, Training and Behaviors
4. Working with Contractors and Others
5. Facilities Design and Construction
6. Operations and Maintenance

7. Management of Change
8. Information and Documentation
9. Customers and Products
10. Community and Stakeholder Awareness
11. Crisis and Emergency Management
12. Incidents Analysis and Prevention
13. Assessment, Assurance and Improvement

The Safety Case Regulations require that the Duty Holder, under Regulation 8, identifies all major accident hazards and puts measures in place to reduce the risks associated with these major accident hazards to “as low as reasonably practicable” or ALARP. The Design and Construction Regulations require the duty holder to have in place:

“.....suitable arrangements for (a) periodic assessment of integrity...” (Reg. 8)

The Prevention of Fire and Explosion, and Emergency Response Regulations require that, having identified the major accident hazards, an assessment be carried out for:

“...the evaluation of the likelihood and consequences of such event...” (Reg. 5)

Similarly, the Pipelines Safety Regulations require that the operator of a pipeline ensures that adequate arrangements have been made for dealing with:

“(b) discovery of a defect in or damage to.....the pipeline ” (Reg. 12)

The Safety Case Regulations require the operator to identify the safety critical elements (SCE) on the facility and draw up a verification scheme for these safety critical elements. Safety critical elements means such parts of an installation and such parts of its plant

- the failure of which could cause or contribute substantially to a major accident
- a purpose of which is to prevent, or limit the effect of, a major accident

The safety critical elements must remain in a good state of repair and in good condition. This is normally ensured by the use of a verification scheme. A verification scheme is a written scheme of examination. In practice, both hydrocarbon containment equipment (pipelines and risers etc.) and structures are safety critical elements. The verification scheme is complementary to, but not a substitute for, routine maintenance programmes and an integrity management system.

The output from the inspections and other activities carried out as part of the integrity management process can be used to satisfy many of the requirements of the verification scheme. The integrity management system is therefore an integral part of the safety management system and as such, an important plank in the argument that major accident hazards have been identified, are being properly managed and that the attendant risks are, and will remain, as low as is reasonably practicable.

In addition to compliance with legislative and company requirements, there is also a significant business benefit from ensuring the integrity of the assets / facilities. Minimizing production losses, prevention of unplanned shutdowns and rationalization of the purchase and storage of spare parts are some of the benefits that can result from a well-managed and executed integrity management system.

Degradation and Failure Modes

There are various degradation and failure modes associated with refineries, pipelines and offshore platforms. The most important ones are listed in the following table

Degradation Mechanism	Influencing Factors	Possible Failure Modes & Scenarios
CO ₂ Corrosion	CO ₂ + water Corrosion inhibition failure	Pitting due to carbonic acid attack, localized loss of wall thickness perhaps leading to more generalized metal loss. Subsequent loss of containment.
H ₂ S + CO ₂ Corrosion	H ₂ S + CO ₂ + water Corrosion inhibition failure	H ₂ S may generative a protective sulphide film, however, local breakdown can lead to severe pitting and subsequent loss of containment.
Sulphide Stress Corrosion Cracking (SSCC)	H ₂ S + water Susceptible steel	Local weakening of material by stress initiated cracking. Possible hydrogen blistering. Mechanical strength compromised affecting pressure retention ability. Subsequent loss of containment
Microbial Induced Corrosion (MIC). Under deposit corrosion (UDC)	Sulphate Reducing Bacteria (SRB) contamination	Deep localized loss of wall thickness, pitting, subsequent loss of containment.
Galvanic Corrosion	Dissimilar metals	Very localized loss of wall thickness close to galvanic couple, loss of containment.
O ₂ Corrosion	O ₂ in Water Injection Systems	Localized loss of wall thickness, grooving corrosion (classic 6 o'clock channel), loss of Mechanical strength, loss of pressure retention ability, subsequent loss of containment.
Erosion	Entrained solids in fluid	Local loss of wall thickness, possibly exacerbated by erosion-corrosion. In severe cases will lead to loss of mechanical strength and possible loss of containment.

Preferential Weld Corrosion	Weld material susceptible to preferential attack Weld misalignment.	Very localized loss of wall thickness in HAZ (knife line attack) or preferential corrosion of weld metal, generally in lower half of pipe. Can lead to cracking and failure of weld. Major loss of containment.
Hydrogen Induced Cracking	H ₂ S + water Residual Mean Stress	Local weakening of material by stress initiated cracking. Cracking of susceptible carbon steel or CRA materials.
Steel or CRA materials. Impacts (Third Party Damage)	Hydrogen Diffusion Excavation Dropped Object Transportation System Accident	Damaged coating, gouging, dents and other mechanical damage, which could lead to localized areas of increased hardness and subsequent cracking. Major damage to coating system, severe external corrosion and subsequent loss of containment.
External Corrosion	Coating Damage CP System Failure CP System Interference CP System Inadequate Dissimilar Metals in contact Contaminated Land	General or localized loss of wall thickness, loss of containment.
Crevice Corrosion	Local chemistry / oxygen levels different to bulk fluids or atmosphere	Localized loss of wall thickness
Stress Corrosion Cracking	Coating Damage CP System Failure CP System Interference CP System Inadequate Backfill/soil environment	Cracking, loss of containment
Structural	Expansion / Buckling Crossing Overload Clamp / Support Failure Vibration / Pressure Cycling / Tunnel / Casing Collapse	Overstressing and / or fatigue. Loss of mechanical strength loss of pressure retention ability, loss of containment.
Material (Construction Defects)	Weld Defect Steel Defect	Local weakness in material leading to overstressing and / fatigue crack initiation and subsequent propagation. Loss of containment.

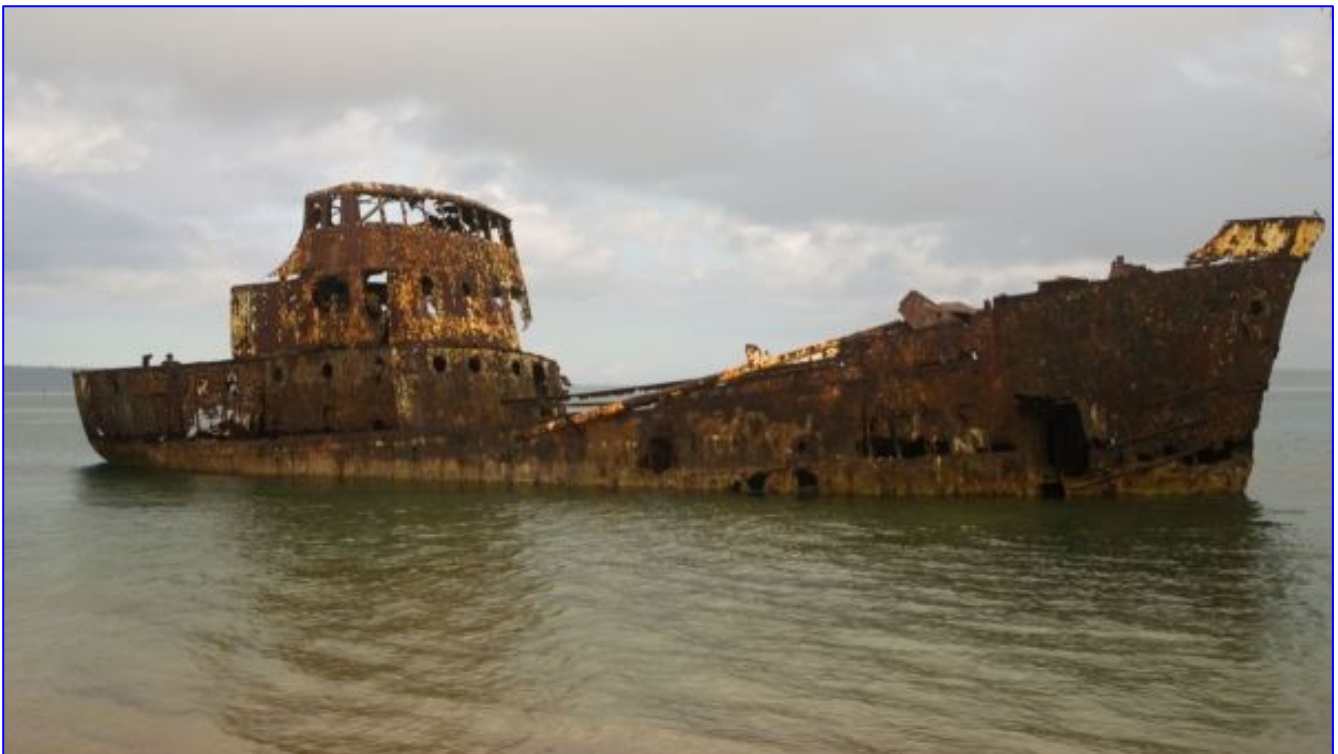
Natural Hazards	Scour (Stability) Buried Pipeline	Overstressing and / or fatigue, loss of mechanical strength and pressure retention ability. Loss of containment.
	Scour (Spans) Exposed Pipeline	
	Subsidence / Earthquake	
	Extreme Storms / Lightning	

Common Degradation Mechanisms and Threats

It is worth looking at the most important degradation modes listed above. Note: the following is a fairly high level overview aimed at giving the reader a feel for the processes involved.

Corrosion

For those old enough to remember, Neil Young is probably most famous for his song; "Southern Man". However, he also wrote an album called; "Rust Never Sleeps." Neil Young wasn't a corrosion engineer but the title of his album could well be considered as one of the fundamental "laws" of degradation and failure of metallic components. Although rust is actually specific to iron based materials, being predominantly iron oxide, it is commonly used as a term to cover all types of corrosion.



Rust Never Sleeps



Paint breakdown and external corrosion

All steel components start off as iron ore, usually magnetite and hematite. Iron is one of the most abundant elements on our planet and has been used as a construction material for thousands of years.

In order to make metallic iron from its ore requires energy. Hence, iron, and steel, which is basically iron with a number of additional elemental additions, is thermodynamically unstable.

That thermodynamic instability will ensure the metal will always try to return to its lower energy level. That process is generally called corrosion for metals and specifically called rusting for iron and steel.

Rusting is an oxidation process. This means that metallic iron will react with oxygen and form iron oxide. That reaction will progress at different rates depending on a number of conditions. In general, the worst conditions will be when the iron or steel is immersed in sea water. The corrosion reactions will involve a transfer of electrons and for that to happen an electrolyte will be needed. Sea water is a very good electrolyte because of its high salt concentration.

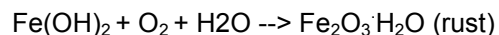
In order for iron and steel to rust, several reactions must take place.

The anodic reaction: $\text{Fe} \rightarrow \text{Fe}^{2+} + 2\text{e}^{-}$

The cathodic reaction: $\text{O}_2 + 4\text{e}^{-} + 2\text{H}_2\text{O} \rightarrow 4\text{OH}^{-}$

Combining these gives: $\text{Fe}^{2+} + 2\text{OH}^{-} \rightarrow \text{Fe}(\text{OH})_2$

$\text{Fe}(\text{OH})_2$ is an insoluble salt that precipitates at the cathode. It is then further oxidized by dissolved oxygen to hydrated ferric oxide, commonly known as rust.



One of the most important aspects of rust is that it is autocatalytic. This means that once rusting starts it will continue unabated unless something is done to stop it. So what can be done to stop it? Well, the easiest way is to prevent it in the first place.

Preventing and Mitigation

Cathodic Protection



Looking at the Cathodic reaction above it can be seen that it involves oxygen. If we can remove oxygen from the equation then the whole oxidation process cannot happen. This is where impervious coatings come into play. One example of this is the thick bitumen coatings used on marine pipelines. The coating actually serves two purposes in this case. It will act as a physical barrier to both oxygen and moisture. Moisture being the electrolyte needed for the reaction to take place. Many paints perform the same function, however, most paints have a secondary method of corrosion prevention and that is the "sacrificial anode" effect.

Corrosion at pipe supports

In order to understand the principles of a sacrificial anode we need to look at the Galvanic Series. Just about everyone knows that Gold is the most unreactive or noble metal. Gold does not form an oxide. At the other end of the scale Potassium is one of the most reactive. It will oxidize explosively and is so reactive it needs to be stored under oil or de-aerated conditions.

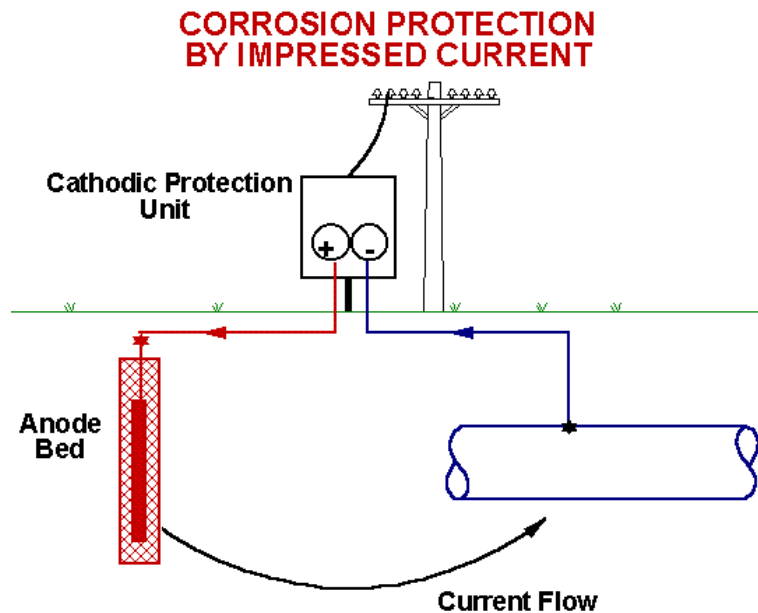


Depending on how reactive a metal is will dictate where on the Galvanic Series it comes. More reactive, then closer to Potassium. Less reactive, then closer to Gold. The interesting thing is that if two dissimilar metals are connected in an electrolyte the more reactive metal will corrode and the less reactive one will not. Quite literally, the more reactive metal will sacrifice itself to save the nobler one and is known as Galvanic Corrosion.

This is the fundamental principle behind sacrificial anodes and why large Aluminium anodes are attached to ships and offshore platforms. It is also how many paints help prevent corrosion. Even though a paint film will reduce the amount of oxygen and moisture contacting the metal surface, it will

Paint breakdown and external corrosion

not eliminate it completely. However, if the paint contains minute flecks of a more reactive metal, such as zinc, these will corrode in preference to the underlying steel structure.



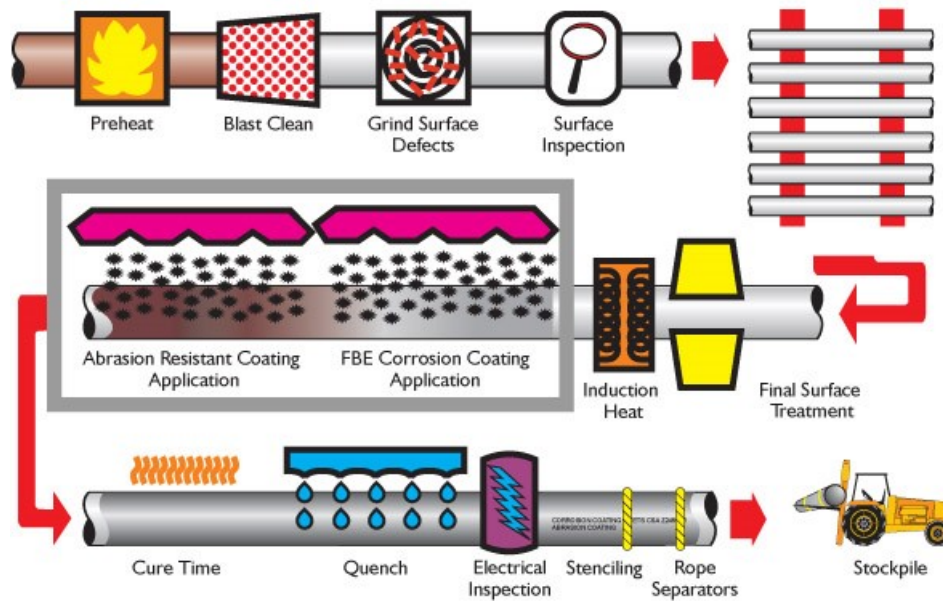
Corrosion Protection by Impressed Current

There are two types of cathodic protection systems: sacrificial anode and impressed current. In a sacrificial anode system the more reactive metal will corrode and according to the anodic reaction, produce electrons. The sacrificial anode is connected to the pipeline via a wire and placed some distance from the pipeline. The current flows from the anode into the surrounding soil (electrolyte) and is picked up by the pipeline at holes in the coating (called holidays). The circuit is completed by a wire that connects the anode to the pipe. Sacrificial anode systems utilize an externally connected sacrificial metal with a relative activity value greater than steel (iron) and thereby protect steel from corrosion. Alloys of zinc and magnesium are the sacrificial metals most commonly employed. The number and placement of anodes is based on the site-specific requirements of the particular pipeline that is to be protected. A well-coated pipeline with a few small holidays does not require many anodes. It is the increase in electron density which inhibits the anodic reaction in the less reactive steel. This property is the principle behind an Impressed Current system of corrosion prevention.

The impressed current dispenses with a sacrificial anode, instead using an electric current, to deliver electrons into the structure to be protected. Impressed-current anodes can be made from graphite, high-silicon cast iron, lead-silver alloys, precious metals, mixed-metal oxides, or steel. As with sacrificial anodes, the shapes, locations, and number depend on the geology of the area and the nature of the pipeline system.

As a general rule of thumb, standard constructional steel will require a potential of approximately -850mV. This voltage level will normally ensure that the corrosion process is stopped or slowed to a very low rate. However, while the Impressed Current system is very effective there can be problems with it. These problems become more serious with higher strength steels and arise if the voltage drops below -850mV. At potentials more negative than -850mV (e.g. -1000mV) we enter the area of overprotection. The increased negative potential causes the production of hydrogen. Unfortunately hydrogen and steel are not a good mix. Hydrogen embrittlement can occur which may reduce the fatigue life of a component by orders of magnitude.

Coatings



Fusion Bonded Epoxy coating process

In the early days of the oil industry common pipeline coatings were coal tar, asphalt or grease based. All were designed to prevent water from reaching the pipe surface. Also they offered some resistance to the passage of electrical current from the environment to the pipe surface. Unfortunately, many of these coatings were difficult to apply and did not successfully bond to the steel surface in a uniform and consistent manner which resulted in voids, pinholes, and other imperfections. Over time the coating were also liable to degrade and become porous or even completely disbond from the steel surface. Nowadays these have been replaced by Fusion Bonded Epoxy (FBE) coatings and “Shrink Sleeve” thermoset plastics.

Offshore pipelines also incorporate concrete coatings to offset buoyancy as well as to prevent fatigue damage where there is scouring or local differences in load bearing capacities of the soil.

Dehydration

For internal pipeline corrosion protection, dehydration is the most commonly used measure for gas pipelines (and also in liquid pipelines that contain oil with free water or other electrolytes). Dehydration removes condensation and free water that, if permitted to remain, would allow internal corrosion to occur at points where water droplets precipitate from the gas stream to either form liquid puddles at the bottom of the pipe, or adhere to the top of the pipe. Complete dehydration is very effective, but, because the systems are neither 100 percent effective nor 100 percent dependable, there always is the potential to introduce water and other electrolytes into a gas pipeline. Glycol is most frequently used as a drying (scrubbing) agent.

Liquid pipelines that contain free water can also experience internal corrosion. The fluid can sometimes be treated to remove both free water and dissolved water. If water has accumulated in low points of the line, pigging is required to move the water from those areas. Water is removed from crude oil by gravity separation in vessels

called separators, which as the name suggests, separate oil, gas and water from the triple phase crude product. However, 100% removal cannot be achieved so the potential for corrosion, although small, will still exist.

Inhibitors

A corrosion inhibitor is a substance when added in small concentrations to an environment reduces the corrosion rate of a metal exposed to that environment. They can adsorb onto the metal surface or react with it to form a protective film, or they may react with the corrodent to make it less corrosive. Many different chemicals are available commercially and they can be Anodic, Cathodic, Mixed or Vapor Phase Inhibitors. The choice will depend on the type of product in the pipeline and the type of corrodent. Other considerations include cost, availability, toxicity, and environmental friendliness.

Internal Coatings

Internal coatings have been used on some gas transmission pipelines to improve product flow by reducing drag and eliminating dust. Such coatings can be somewhat effective in controlling internal corrosion, but they are very difficult to apply uniformly, which impacts their effectiveness. In lieu of coatings, some operators have attempted to install plastic or high-density polyethylene liners or inserts in their pipelines. Plastic liners are an effective barrier against corrosion but are not fail-safe. Problems occur if pinholes are present and allow corrosive materials to migrate behind a pipe's liner. For this reason internal corrosion prevention should not rely solely on liners or coatings.

Buffering

Buffering agents, such as a mild or dilute alkaline mixture, that change the chemical composition of fluids and remain in the pipeline can be utilized to prevent internal corrosion. They can significantly reduce the corrosivity of any standing liquid, predominantly by raising its pH value above seven (neutral), so that it turns from acidic to alkaline. Alkaline liquids cause virtually no harm to steel. However, in general, pH buffering is not a very effective means of corrosion inhibition in large scale operations.

Cleaning Pigs

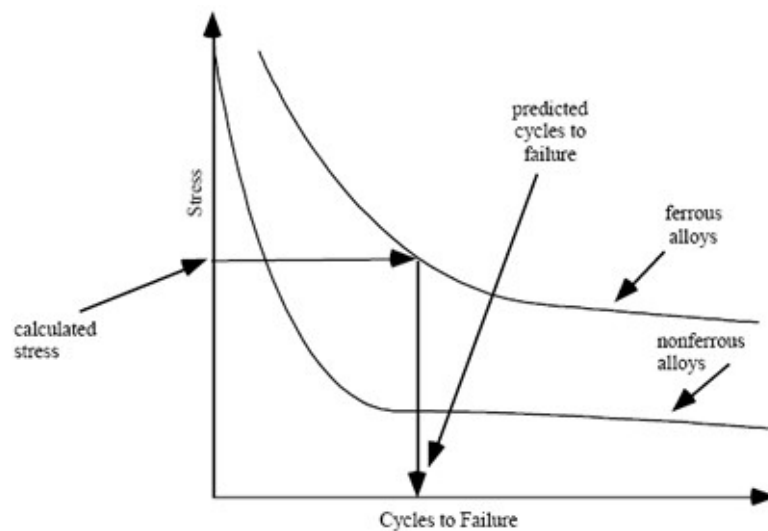
The frequent use of cleaning pigs to scour the internal surfaces of a pipeline is another viable preventive measure. There are many types of cleaning pigs. The choice of which type of pig to use depends on the product carried by the pipeline and the contaminant to be removed. Able to operate without interrupting operations, the pig is forced along by product flow, or it can be towed by another device or cable. Usually cylindrical or spherical, pigs sweep the line by scraping the sides of the pipeline and pushing debris ahead. Cleaning pigs can effectively direct both liquids and corrosive solids to pig traps for removal from the pipeline. It is noted that the buildup of solids can also cause internal corrosion, since the solids can entrap corrosive or low-pH liquids in a corrosive matrix.

It is widely recognized that sea water is one of the most aggressive natural environments on the planet. However, many refineries and chemical plants contain chemical mixtures which can destroy "ordinary" constructional

materials in a very short time. In these cases it is necessary to use "exotic" materials such as highly alloyed stainless steels or alloys with high concentrations of Nickel and Copper such as Inconel or Monel. Many of these alloys form inert and tenacious oxide films which form barriers to whatever aggressive medium they are in contact with. These materials tend to be very expensive and require extra care in fabrication, especially welding, but in many situations there are few alternatives.

Fatigue

Fatigue is a degradation process where cyclic loads over an extended period reduce the strength of a material and eventually cause failure. This cyclic loading can be mechanical, e.g. vibration, or thermal. Fatigue can be easily demonstrated by taking a paper clip and bending it back and forth several times. It will start to become more pliable and then break in two. This is low cycle, high amplitude fatigue. Fatigue got its name because when the phenomenon was first analyzed it was thought that the metal got tired and was suffering "fatigue". The name stuck even after the mechanism was understood. What makes fatigue so onerous is that the cyclic loads applied can be much less than the Ultimate Tensile Stress and even the Yield Stress of the material and still failure can occur. Reducing the magnitude of the cyclic stress increases the number of cycles before the component fails, but it will still eventually fail.



Stress vs Cycles to Failure

All engineering alloys are subject to fatigue cracking although the stress levels and number of cycles necessary to cause failure vary by material.

There are three stages of fatigue failure:

1. Crack initiation in the areas of stress concentration (near stress raisers)
2. Incremental crack propagation
3. Final rapid crack propagation after crack reaches critical size

The total number of cycles to failure is the sum of cycles at the first and the second stages:

$$N_f = N_i + N_p$$

N_f: Number of cycles to failure

N_i : Number of cycles for crack initiation

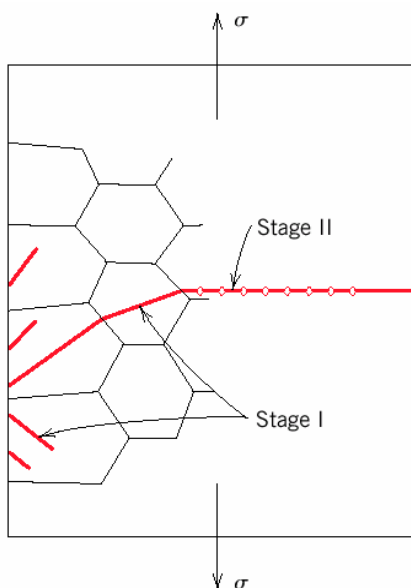
N_p: Number of cycles for crack propagation

For high cycle fatigue (low loads): **N_i** is relatively high. With increasing stress level, **N_i** decreases and **N_p** dominates

For crack initiation, surface condition is important. Fatigue cracks usually initiate on the material surface at sites of stress concentration such as notches or stress raisers (microcracks, scratches, indents, interior corners, dislocation slip steps, etc.) Not unexpectedly, the design of a component can play an important part in determining resistance to fatigue failure. Geometries which offer smooth transitions and curves rather than steps and notches reduce the locations where fatigue cracks can initiate. Several common surface features can lead to the initiation of fatigue cracks as they can act as stress concentrations. Some of these features are:

- Mechanical notches (sharp corners or grooves);
- Key holes on drive shafts of rotating equipment;
- Welded joints, flaws and / or mismatches;
- Quenched areas;
- Tool markings;
- Weld spatter;
- Grinding marks;
- Drilled holes / penetrations;
- Threads

Inclusions found in metal can accelerate the effect of fatigue cracking. Unfortunately most older steels are “dirty” which means they have increased levels of inclusions or slag entrapment and as such offer lower resistance to fatigue initiation and propagation. Welding by its nature of rapid heating and cooling will introduce micro discontinuities to a metal surface which can act as crack initiators.

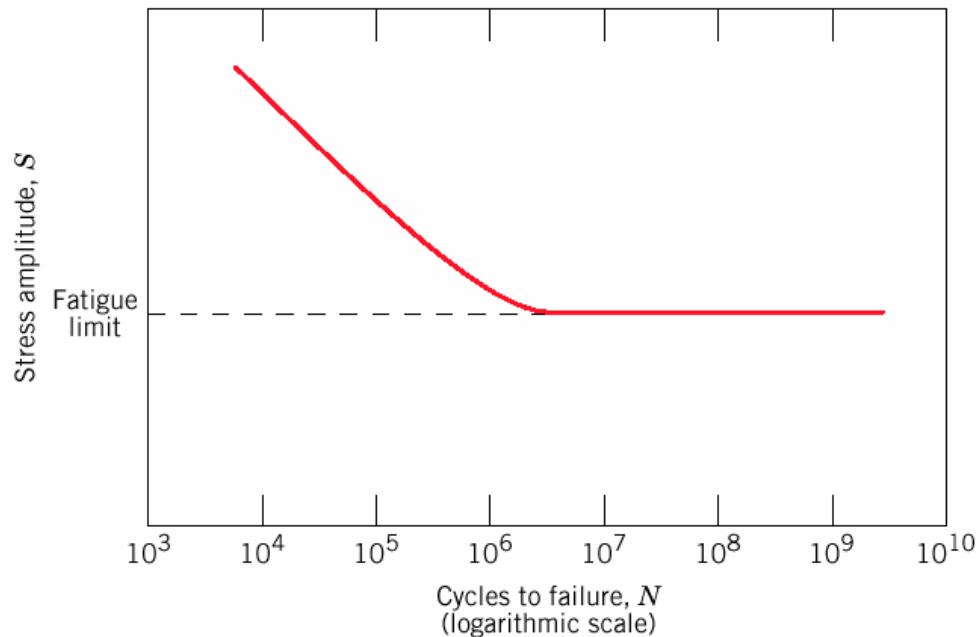


Crack propagation normally exhibits two stages:

Stage I: slow propagation along crystal planes with high resolved shear stress. Involves just a few grains, and exhibits a flat fracture surface

Stage II: faster propagation perpendicular to the applied stress. Crack grows by repetitive blunting and sharpening process at crack tip and exhibits a rough fracture surface.

The crack eventually reaches a critical dimension and propagates very rapidly until failure.



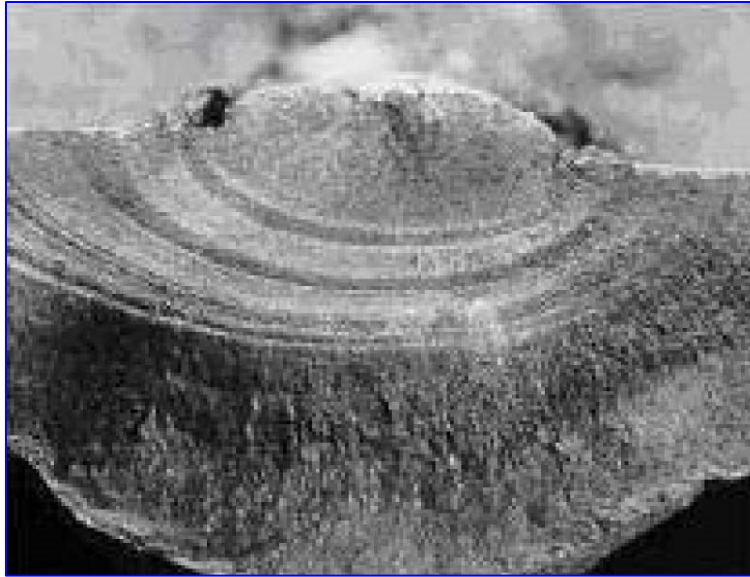
Fatigue Limit

For some materials such as titanium, carbon steel and low alloy steel, the number of cycles to fatigue fracture decreases with stress amplitude until a fatigue limit (endurance limit) is reached. Below this stress endurance limit, fatigue cracking will not occur, regardless of the number of cycles. For alloys with fatigue limits, there is a correlation between Ultimate Tensile Strength (UTS) and the minimum stress amplitude necessary to initiate fatigue cracking. The ratio of fatigue limit over UTS is typically between 0.4 and 0.5.

Heat treatment can have a significant effect on the toughness and hence fatigue resistance of a metal. Generally, it is fine grained microstructures which tend to perform better than coarse grained ones. Heat treatments such as quenching and tempering, can improve fatigue resistance of carbon and low alloy steels. Also introducing compressive stresses into a thin surface layer by "Shot Peening" - firing small shot onto the surface to be treated will increase fatigue resistance. Case hardening which creates a Carbon or Nitrogen rich outer layer in steels by atomic diffusion makes a harder outer layer and also introduces compressive stresses.

Appearance or Morphology of Damage

Fatigue failure is easy to spot on a macroscopic level. The crack surfaces of the failed component have a characteristic "clam shell" type appearance that has concentric rings called "beach marks" which radiate out from the crack initiation site. These "beach marks" may contain thousands of smaller ridges called "Striations". Striations are thought to be steps in crack propagation, where the distance between them depends on the stress range and are a function of the cyclic nature of fatigue. These concentric cracks continue to propagate until the cross - sectional area is reduced to the point where failure occurs due to the fact that the ligament of uncracked material is unable to resist the forces acting on it. The typical single clam shell appearance results from a fatigue crack which nucleates from a single surface stress concentration or defect. Cracks resulting from cyclical overstress of a component without significant stress concentration will typically result in a fatigue failure with multiple points of nucleation and hence multiple "clam shell" fingerprints. These multiple nucleation sites are the result of microscopic yielding that occurs when the component is momentarily cycled above its yield strength.



Fatigue fracture surface of a carbon steel pipe

Prevention and Mitigation

The best defense against fatigue cracking is good design that helps minimize stress concentration of components that are in cyclic service.

Select a metal with a design fatigue life sufficient for its intended cyclic service. Allow for a generous radius along edges and corners.

Minimize grinding marks, nicks and gouges on the surface of components. Insure good fit up and smooth transitions for welds.

Minimize weld defects as these can accelerate fatigue cracking.

Remove any burrs or lips caused by machining.

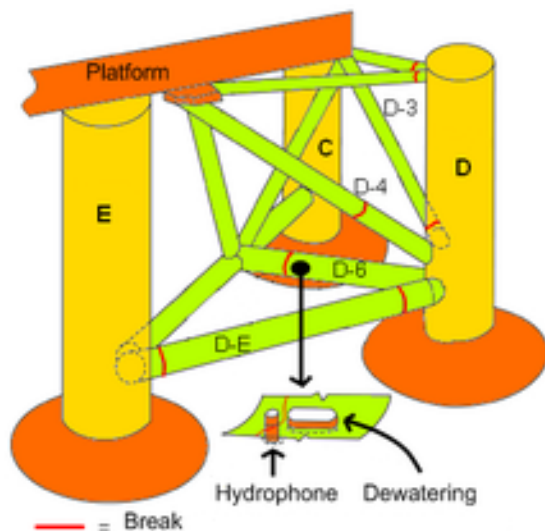
Use low stress stamps and marking tools.

Non Destructive Examination (NDE) techniques such as Liquid Penetrant Testing, Magnetic Particle Testing and Shear Wave Ultrasonic Testing can be used to detect fatigue cracks at known areas of stress concentration. Visual Inspection of small diameter piping can detect oscillation or other cyclical movement that could lead to cracking. Vibration monitoring of rotating equipment can help detect shafts that may be out of balance. In high cycle fatigue, crack initiation can be a majority of the fatigue life making detection difficult.

One of the greatest tragedies and loss of life in the Oil Industry can be traced to welding and a fatigue crack: The *Alexander L. Kielland* was a Norwegian semi-submersible drilling rig that capsized whilst working in the Ekofisk oil field in March 1980 killing 123 people. The capsizing was the worst disaster in Norwegian waters since World War II. The rig, located approximately 320 km east from Dundee, Scotland, was owned by the Stavanger Drilling

Company of Norway and was on hire to the U.S. company; Phillips Petroleum at the time of the disaster. In driving rain and mist, early in the evening of 27 March 1980 more than 200 men were off duty in the accommodation on the *Alexander L. Kielland*. The wind was gusting to 40 knots with waves up to 12 m high. The rig had just been winched away from the *Edda* production platform. Minutes before 18:30 those on board felt a 'sharp crack' followed by 'some kind of trembling'. Suddenly the rig heeled over 30° and then stabilized. Five of the six anchor cables had broken, the one remaining cable preventing the rig from capsizing. The list continued to increase and at 18.53 the remaining anchor cable snapped and the rig turned upside down.

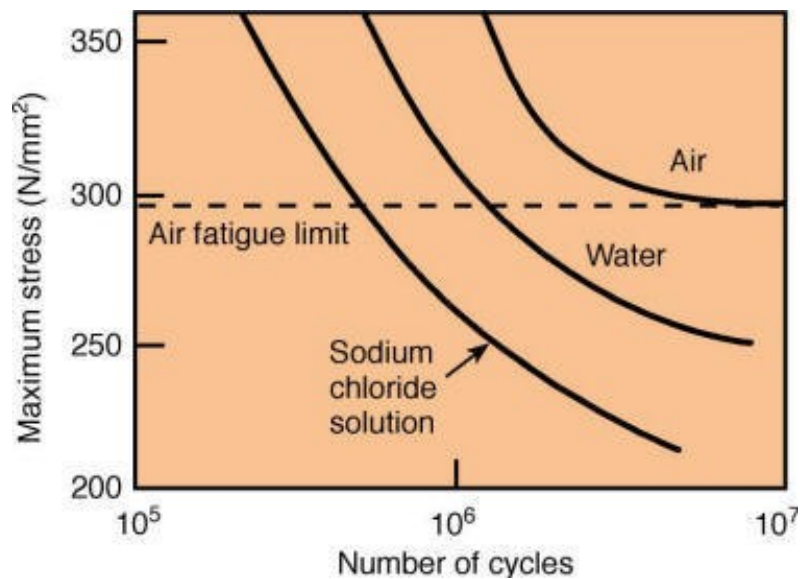
A year later in March 1981, the investigative report concluded that the rig collapsed owing to a fatigue crack in one of its six bracings (bracing D-6), which connected the collapsed D-leg to the rest of the rig. This was traced to a small 6 mm fillet weld which joined a non-load-bearing flange plate to this D-6 bracing. This flange plate held a sonar device used during drilling operations. The poor profile of the fillet weld contributed to a reduction in its fatigue strength. Further, the investigation found considerable amounts of lamellar tearing in the flange plate and cold cracks in the butt weld. Cold cracks in the welds, increased stress concentrations due to the weakened flange plate, the poor weld profile, and cyclical stresses due to wave loading, seemed to have collectively played a role in the rig's collapse.



Fractures on the bracing of the Alexander L. Kielland rig

Corrosion Fatigue

As bad as the problem of fatigue is, it is much worse when corrosion is introduced producing a phenomenon called Corrosion Fatigue. In this case chemical reactions induce pits which act as stress raisers. The corrosion also enhances crack propagation. The effect of Corrosion Fatigue is termed synergistic. In simple language this means that the effect of both conditions taken together are greater than the sum of them when taken separately. In essence; $(2 + 2) = 5$. Ultimately if a metal is simultaneously exposed to a corrosive environment, the failure can take place at even lower loads and after shorter time.



Fatigue Limits

In a corrosive environment the stress level at which it could be assumed a material has infinite life is lowered or removed completely. Contrary to a pure mechanical fatigue, there is no fatigue limit load in corrosion-assisted fatigue.

Corrosion fatigue and fretting are both in this class. Much lower failure stresses and much shorter failure times can occur in a corrosive environment compared to the situation where the alternating stress is in a non-corrosive environment.

The fatigue fracture is brittle and the cracks are most often transgranular, as in stress-corrosion cracking, but not branched. The corrosive environment can cause a faster crack growth and/or crack growth at a lower tension level than in dry air. Even relatively mild corrosive atmospheres can reduce the fatigue strength of aluminum structures considerably, down to 75 to 25% of the fatigue strength in dry air.

Corrosion Under Insulation

An offshore platform presents a particularly harsh environment for steel. Pipework needs to be protected either by wrapping or coatings. Some pipework also needs to be wrapped because the contents are at a very high temperature and the wrapping will be used for either insulation or protection or both. Unfortunately it is very difficult to examine pipes which are covered with any kind of wrapping and from a corrosion point of view; it has been very much a case of "out of sight, out of mind". If the wrapping becomes perforated and water is allowed to collect inside the wrapping then there is a very high likelihood of increased corrosion activity. This phenomenon is termed: Corrosion Under Insulation (CUI).

Water and oxygen are the main drivers for this type of corrosion. The water can come from rain water, leakage, deluge system water, wash water, or sweating from temperature cycling or low temperature operation such as refrigeration units.



Corrosion under insulation

The majority of problems occur with carbon steels and 300 series stainless steels. On carbon steels it manifests as generalized or localized wall loss. With the stainless pipes it is often pitting and corrosion induced stress corrosion cracking.

Though failure can occur in a broad band of temperatures, corrosion becomes a significant concern in steel at temperatures between 0 and 149°C (32 - 300°F) and is most severe at about 93°C (200°F). Corrosion and corrosion induced stress corrosion cracking (CISCC) rarely occur when operating temperatures are constant above 149°C (200°F).

API 570 (Piping Inspection Code) specifies the following areas as susceptible to CUI:

- Areas exposed to mist overspray from cooling water towers.
- Areas subject to process spills, ingress of moisture, or acid vapors.
- Areas exposed to deluge systems.
- Areas exposed to steam vents.
- Carbon steel piping systems, including those insulated for personnel protection, operating between -4°C and 120°C. CUI is particularly aggressive where operating temperatures cause frequent condensation and re-evaporation of atmospheric moisture.
- Carbon steel piping systems that normally operate in-service above 120°C but are intermittent service.
- Deadlegs and attachments that protrude from insulated piping and operate at a temperature different than the active line.
- Austenitic stainless steel piping systems that operate between 60°C and 204°C. These systems are susceptible to chloride stress corrosion cracking.

- Vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress.
- Piping systems with deteriorated coatings and/or wrappings.
- Steam traced piping systems that may experience tracing leaks, especially at the tubing fittings beneath the insulation.
- Locations where insulation plugs have been removed to permit thickness measurements on insulated piping should receive particular attentions.

The followings are common locations on piping systems susceptible to CUI:

a) All penetrations or branches in the insulation jacketing system, such as:

Deadlegs such as Vents, drains

Pipe hangers and other supports

Valves and fittings (irregular insulation surface)

Bolted-on pipe shoes

Steam tracer tubing penetrations

b) Termination of insulation at flanges and other piping components.

c) Damaged or missing insulation jacketing

d) Termination of insulation in a vertical pipe

e) Caulking that has hardened, has separated or missing

f) Bulges or staining of the insulation or jacketing system or missing bands

Inspection and prevention of CUI is possible. The best way to inspect for CUI is to completely remove the covering; however, this can be time consuming, costly and impractical in many cases. Ultrasonic testing, x-ray, eddy currents, electro-magnetic devices and remote monitoring are also used with varying degrees of success. However, when dealing with CUI, experience and efficient monitoring systems can be extremely beneficial. Previous experience of similar systems will identify locations of high susceptibility, for example, low spots in the line and areas which have a temperature profile which means water will remain in liquid form and not evaporate off. These areas can be ranked and given a risk factor.

It is this allocation of risk which is providing tremendous benefits in terms of efficiency and cost savings over traditional inspection methods. Risk Based Inspection software will utilize current and historical information and produce a prioritized inspection regime. It is by prioritization that cost savings and efficiency can be achieved. Without prioritization, inspection can fall into the "shotgun" or "hit and miss" approach which really only results in what is termed "firefighting". Areas are inspected because they are easy to get at or they have been problematic in the past. The actual efficiency of the inspection regime will be quite low because many potential problem areas will be missed. We will spend a lot of time, energy and resources doing this "firefighting". The smarter way to deal with the problem is to stand back and have a look at the whole system and determine what causes the "fires" to occur in the first place. We can then address the instigators of these problems and if we take care of

those then effectively the problems never arise. Part of that "stand back and have a look" necessitates an effective inspection regime.

Prevention is mainly through ensuring that water does not intrude into the system. There are a number of factors which contribute to prevention, these include:

Insulation selection

Protective paints and coatings

Equipment design

Maintenance practices

Weather barriers

In recent years, the CUI prevention philosophy of many large petrochemical companies has been an inspection-free, maintenance-free concept. Insulated systems particularly piping systems are expected to have a service life of 25 to 30 years. In order to achieve that 2 simple approaches are now recommended for CUI prevention:

(A) Applying thermal spray aluminum (TSA) on carbon steel to prevent general corrosion, and on austenitic stainless steel to prevent stress corrosion cracking.

With TSA, aluminum particles are bonded to the metal substrate mechanically.

The two common thermal spray techniques used to apply TSA to components are wire flame spray and twin wire electric arc spray. Adhesion to the substrate is considered largely mechanical and is dependent on the work piece being very clean and suitably rough. Roughening is carried out by grit blasting to a white metal condition with a sharp, angular profile in the 50-to-100 micron (2-to-4 mil) range. Flame and arc spraying require relatively low capital investment and are portable; they are often applied in open workshops and on site. Consumables used for TSA with these processes are more than 99-percent purity aluminum wires.

(B) Using aluminum foil wrapping on austenitic stainless steel pipe to prevent stress corrosion cracking.

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.

Wrapping pipe with 46 SWG (wire gauge) 0.1-millimeter (mm) aluminum foil can prevent Corrosion Induced SCC of stainless steel pipe operating continuously between 60°C and 175°C (140°F and 347°F). The pipe should be wrapped with 50-mm overlap, formed to shed water on the vertical line, and held with aluminum or stainless wire. The foil should be moulded around flanges and fittings. Steam-traced lines should be double wrapped, with the first layer applied directly onto the pipe, followed by the steam tracing, and then more foil over the top. On vessels, the aluminum foil is applied in bands held by insulation clips and insulation support rings.

Microbiologically Influenced Corrosion (MIC)



Microbiologically Influenced Corrosion

The basics of corrosion have been covered earlier in the book. In this section we will literally add microorganisms to the mix. The microbes don't "eat" the metal, but they do form colonies and multiply and it is that multiplication which accelerates the corrosion process by introducing very complex chemical, electrical, and biological systems during the growth cycle.

MIC is not caused by a single microbe, but is attributed to many different microbes. These are often categorized by common characteristics such as by-products (i.e., sludge producing) or compounds they effect (i.e. sulfur oxidizing). In a general sense, they all fall into one of two groups based upon their oxygen requirements; one being aerobic (requires oxygen) such as sulfur oxidizing bacteria, and the other being anaerobic, (requires little or no oxygen), such as sulfate reducing bacteria. Other types include iron-oxidizing/reducing bacteria, manganese oxidizing bacteria, and bacteria secreting organic acids and slime.

- * Sulfur-oxidizing bacteria oxidize elemental sulfur to form sulfuric acid. A strong mineral acid, sulfuric acid can cause very acidic conditions to develop, leading to very rapid attack of steel. It is thought that once the acidic conditions develop, bacteria may no longer be required to continue the corrosion process.
- * Sulfate-reducing bacteria (SRB) are strict anaerobes: They can thrive only in a completely oxygen-free environment. They obtain the oxygen they require by extracting it from sulfate ions in the water. SRB also utilize hydrocarbons as food, but actually prefer to use the organic acids given off by Acid Producing Bacteria.
- * Acid-producing bacteria (APB) partially oxidize hydrocarbons to form organic acids. APB are usually the first to colonize the surface of the metal. They thrive under virtually all conditions, from fully aerated water to waters in which there is only a slight amount of oxygen in it, typically in the range of 0.1 parts per million (ppm). These bacteria use oxygen to metabolize hydrocarbons, producing organic acids such as acetic acid, formic acid and propionic acid. These bacteria can cause very acidic conditions to

develop beneath the colony. By consuming oxygen as it diffused through the biofilm, APB also create oxygen flow conditions under the colony, which permit anaerobic sulfate-reducing bacteria to thrive.

* Iron-precipitating bacteria, which are generally considered to be aerobic are characterized by the precipitation of filamentous iron and manganese hydroxides and by the formation of a hard sheath or coating of iron hydroxide around the bacterium. When these bacteria become attached to a metal surface, the result is the formation of a blister-like growth known as a tubercle. One type, *Gallionella*, tends to concentrate chlorides in their deposits, which act as dilute acid, and are uniquely corrosive.

General corrosion affects the entire surface or at least the wetted surface. MIC, on the other hand, is very localized. It creates a nodule and a pit beneath the nodule. There can be only a few nodules or there can be many. Within these nodules microbes rarely work alone but operate as a mixed community of differing types and groups. The different microorganisms perform different functions within the community. This interaction allows a community to thrive in environments that are actually hostile to some of its members. For example, in an aerobic environment, anaerobic bacteria are generally inhibited or killed. But within a community the aerobic bacteria reside in the outer layer (Biofilm) of the nodule consuming the oxygen in the water as it penetrates the nodule. Thus, the inner portion of the nodule experiences a reduced oxygen level allowing anaerobic bacteria to thrive.



Microbiologically Influenced Corrosion

Corrosive bacteria can thrive in all aqueous environments, from fully aerated to low oxygen to oxygen free conditions, as long as the environment has a nutrient source for the bacteria. In hydrocarbon storage tanks, bacteria can thrive in the water layer at the bottom of the tanks, where they consume oil and form slimy black colonies on the floors and walls of the tank. They seem to particularly thrive at the edge of sediment deposits at the bottom of tanks. Once these bacteria become established and active, it is difficult to control them. They can perforate steel rapidly at rates 50 times that of normal corrosion in seawater. Bacteria can also generate poisonous hydrogen sulfide gas which has been the cause of a number of deaths of workers entering tanks.

The presence of the hydrogen sulfide and organic acids under the bacteria colonies creates galvanic concentration cells that cause corrosion. Further, under aerated conditions, it is possible for the hydrogen sulfide to oxidize to elemental sulphur.

The production and pipeline industries have had extensive experience with bacterial corrosion problems and have therefore developed strategies and techniques to deal with this problem. First, offshore oil and gas wells are frequently drilled with seawater-based drilling muds. These muds have resulted in producing wells contaminated with bacteria. The wells subsequently feed bacteria into production piping systems. Serious corrosion problems occur in these production piping systems. Corrosion can cause leaks and failures in offshore pipelines in as few as 4 years if no control measures are taken. The production piping systems, in turn, often feed the bacteria into storage tanks and crude oil tankers, where further corrosion problems arise.

Bacteria have also been the cause of serious corrosion problems in the secondary recovery of oil. In this process, additional oil is produced by injecting water into oil-bearing rock. Produced water, seawater, and make-up water from various sources such as lakes and streams are used in this enhanced recover technique. Produced water is the water produced along with the oil from oil wells. All of the water is deaerated to reduce corrosion, but this can provide an ideal growth medium for SRB. Bacteria are especially a problem when produced water containing hydrocarbon residuals is used. Many fields have turned sour, and pipelines and other facilities have been destroyed by the corrosion generated by these bacteria.

Offshore platform drain system sumps have also been a very serious problem, as deck washings containing oil are drained into sump caissons. The system becomes stagnant and SRB thrive, reaching concentrations of 1,000,000 to 10,000,000 per ml, with the water turning black. When the oil is recovered and put into pipelines, serious corrosion problems often result.

On FPSOs, MIC can occur in ballast tanks and at the bottom of oil cargo tanks. In ballast tanks, corrosion from aerobic APB occurs on the walls and bottoms of the tanks, especially at the edge of sediment deposits. In cargo tanks, anaerobic bacteria can thrive in the water layer that collects in the bottoms of the tanks.

Not surprisingly, the main line of attack against MIC is to eliminate the microorganisms involved using chemicals which exhibit biocidal properties. Typical Oil Field biocide options fall into two main categories:

Non Oxidizers

Glutaraldehyde
THPS (Tetrakis Hydroxymethyl Phosphonium Sulfate)
Quaternary ammonium

Oxidizers

Chlorine
Chlorine dioxide
Peracetic acid, Sodium bromide, bleach, ozone

Non oxidizers typically have a slower microbial kill but are more persistent and more common in the oil field, however, because they are environmentally unfriendly they are being scrutinized.

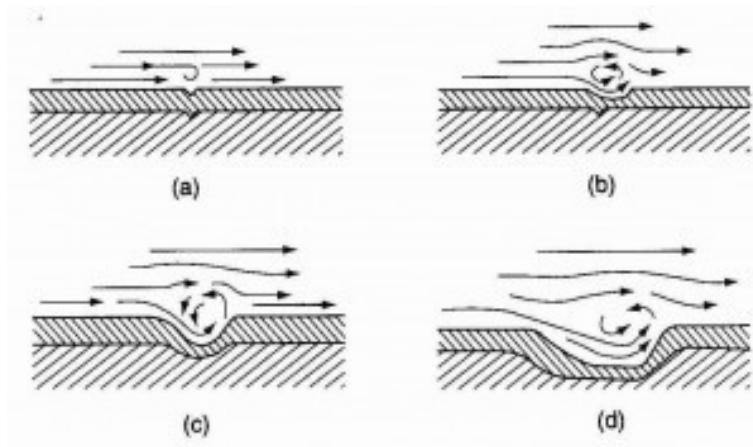
Oxidizers are considered to be fast kill and significantly more reactive and less persistent. Oxidizers are gaining position due to improved efficacy and environmental benefits. Of these, Chlorine Dioxide has advantages due to:

- Not requiring long residence time in tanks or pits to achieve desired efficacy.

- Performs in a wide pH range (<10)
- Penetrates cell wall of microorganisms
- Prevents organisms from building a resistance
- Eliminates bio-film on process surfaces
- Removes iron and manganese
- Eliminates H₂S
- Favorable regulatory status under the Safe Drinking Water Act

Erosion Corrosion

Erosion-corrosion is caused by the relative movement between a corrosive fluid and a metal surface. The mechanical aspect of the movement is what induces friction and subsequent wear and metal removal. This process leads to the formation of grooves, valleys, wavy surfaces, holes, etc., with a characteristic directional appearance (comet tails, horseshoe marks, etc).



Errosion Corrosion

Most metals and alloys can be affected, particularly soft materials (e.g. copper, lead, etc.) or those whose corrosion resistance depends on the existence of a surface film (aluminum, stainless steels). It is generally recognized that there are 5 main elements in the phenomenon:

- (1) Turbulent flow, fluctuating shear stress, and pressure impacts
- (2) Impact of suspended solid particles
- (3) Impact of suspended liquid droplets in high-speed gas flow

(4) Impact of suspended gas bubbles in aqueous flow

(5) The violent collapse of vapor bubbles following cavitation

The five mechanical force sources listed above can be found in oil and gas production. The fluids to induce erosion-corrosion may be single phase like the portable water or multiphase flows such as various combinations of gas, oil, water, and solid particles.

Turbulence phenomena can destroy protective films and cause very high corrosion rates in materials otherwise highly resistant under static conditions. In the laminar flow regime, the fluid flowrate has a variable effect depending on the material concerned.

In two-phase liquids (containing suspended solid particles or gas bubbles), the impact of the particles can damage or even eliminate the protective layers or passive films that are normally stable in the absence of particles, and the local corrosion rate is then markedly accelerated. This phenomenon is called abrasion-corrosion and is most commonly seen in systems where there has been an increase in sand coming from the well.

A few typical problems of erosion-corrosion in oil and gas production are specifically mentioned as follows:

- Downhole components.

Petroleum and mining drill bits are subjected to highly abrasive rock and high velocity fluid so that erosion corrosion is among the most failure mechanisms of downhole components. The entire downhole tubing string is exposed to erosion-corrosion, but points of radical flow diversion or constriction such as pumps, downhole screens, chokes, and subsurface safety valves are particularly at risk. In the downholes of gas wells, the erosion-corrosion may result from the impingement of mixtures of corrosive liquid droplets.

- Systems used to contain, transport and process erosive mineral slurries

This is particularly important for the oil sand industry of northern Alberta, Canada, where handling and processing of essentially silica-based sand (tar sand) results in severe erosion-corrosion problems.

- Petroleum refinery equipment components, typically, pump internals, thermo wells, piping elbows, nozzle, valves seats, and guides, experience varying degrees of high temperature erosion and corrosion

The erosion-corrosion effects are predominant in fluidized catalytic crackers, delayed cokers, flexicokers, thermal crackers, and vacuum distillation units. High temperature crude oil moving with high velocity across the tube wall surface may cause severe localized damage.

Cavitation-corrosion is a particular form of erosion caused by the "implosion" of gas bubbles on a metal surface. It is often associated with sudden variations in pressure related to the hydrodynamic parameters of the fluid (e.g. hydraulic turbine blades, propellers, stirrer blades, etc. A good surface condition decreases the number of potential sites for the formation of vapor bubbles. An increase in fluid pressure is often sufficient to maintain a single phase fluid, thus avoiding the formation of vapor bubbles.

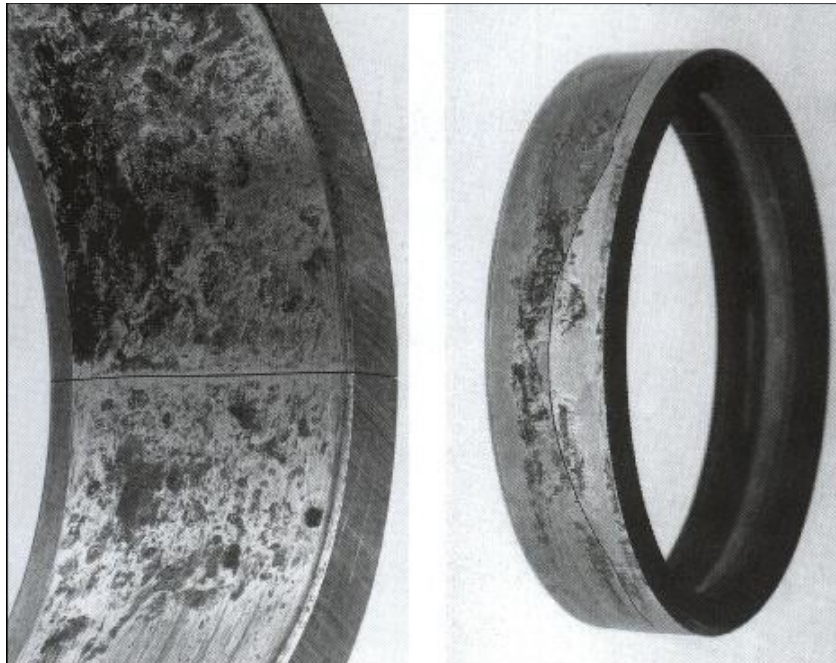
Fretting

Fretting exists when two adjoining contact surfaces in relative motion are subject to a load. It is most common in equipment involving vibrating or moving parts, due to constant friction. Fretting damage involves both mechanical and chemical factors. The former is the dislodgement of metal particles by the wear action produced by the rubbing surfaces. The latter is associated with the processes which promote the oxidation of the metal particles.

Fretting affects all metals. The most common occurrences are found in tube/baffle areas of heat exchangers and connecting devices such as gears, hinges, bearings, etc. The critical factors are:

- Magnitude of the load on the surface, a larger load will cause more stress and wear on contact surfaces.
- Dryness of the contact surface causes more friction and wear.
- Amplitude of movements or vibrations
- Direct contact of surface with air/oxygen (oxidation occurs)

In instances of fretting corrosion, visible surface damage will be evident. A reddish brown deposit is often present in the areas around fretting damage, as well as noticeable cracks.



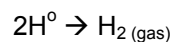
Roller bearing inner ring with fretting corrosion and a transverse crack right through the ring

Prevention / Mitigation can be facilitated by:

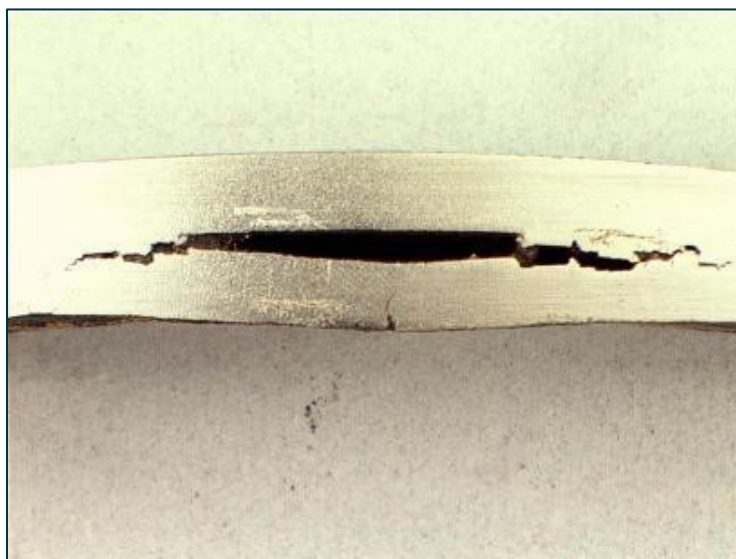
- Use of lubricants and surface coatings will limit metal-on-metal wear as well as inhibit oxidation at the exposed surfaces.
- Dampening/minimizing vibrations at contact surfaces will reduce friction and potential fretting.
- Using stronger/harder materials will allow for less wear at contact surfaces.

Hydrogen Induced Cracking (HIC)

HIC is a poorly understood phenomenon whereby cracks in metallic materials occur in the presence of hydrogen. Hydrogen is the smallest atom and it can diffuse easily through metallic structures. When the crystal lattice is in contact or is saturated with atomic hydrogen, the mechanical properties of many metals and alloys are detrimentally effected (most notably, hydrogen embrittlement) either due to the formation of gaseous hydrogen or by the hydrogen atom effecting the electron configurations of surrounding atoms. Atomic Hydrogen can be produced a number of ways including; cathodic overprotection, welding and as part of the corrosion process. Normally the atomic hydrogen would combine into the molecular form of hydrogen gas as shown in the following equation.



If the formation of molecular hydrogen is suppressed, the nascent atomic hydrogen can diffuse into the interstices of the metal. There are many chemical species which poison this gaseous recombination (e.g. cyanides, arsenic, antimony, or selenium compounds). However, the most commonly encountered species is hydrogen sulfide (H_2S), which is formed in in many petrochemical processes and is a major constituent in “Sour” oil fields.



Hydrogen Induced Cracking

Processes or conditions involving wet hydrogen sulfide, i.e. sour services, and the high incidence of sulfide-induced HIC has resulted in the terms Sulfide Stress Cracking (SSC). The SSC of medium strength steels has been a continuing source of trouble in the oil fields because the cracking of susceptible materials occurs at stress levels well below the yield stress.

Failures have occurred in the field when storage tank roofs have become saturated with hydrogen and then been subjected to a surge in pressure, resulting in the brittle failure of circumferential welds. In rare instances, even copper and Monel 400 have been subjected to HIC. More resistant materials, such as Inconels and Hastelloys, often employed to combat HIC, can become susceptible under the combined influence of severe cold work, the presence of hydrogen recombination poisons, and a direct current from the galvanic couple due to electrical contact with a more anodic member.

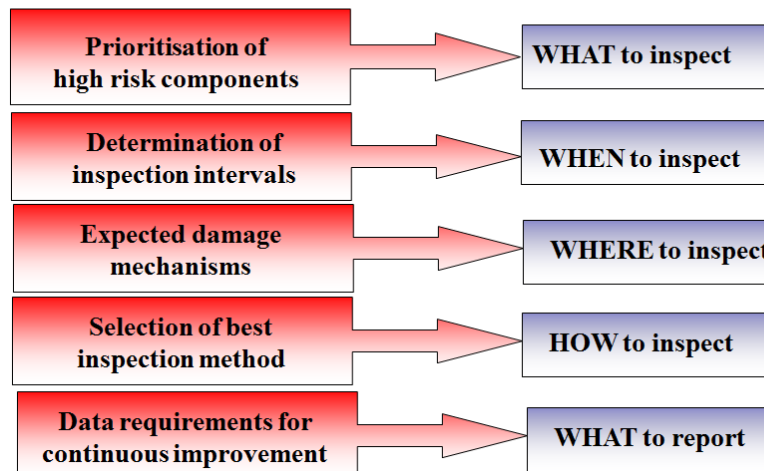
The mechanism of HIC has not been definitely established. Various factors are believed to contribute to unlocking the lattice of the metal, such as hydrogen pressure at the crack tip, the competition of hydrogen atoms for the lattice bonding electrons, the easier plastic flow and dislocation formation 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.

Risk Based Inspection (RBI)

Statutory legislation requires that the integrity of pressure systems is maintained to minimize the risks of injury to persons at work and the release of materials harmful to the environment. Maintaining the integrity of these pressure systems is also essential to minimize plant downtime and to maximize revenue from an asset.

Aims of RBI

- The deliverable of an RBI assessment is an inspection programme that covers:



Typical Aims of RBI

Risk Based Inspection (RBI) is a method used for identifying and managing the risks associated with the integrity of pressure systems in order to reduce them down to an ALARP (as low as reasonably practicable) level or

mitigate them completely. This method is used as a basis for prioritizing and managing the efforts of an inspection program to ensure that inspection is carried out in a cost-effective manner and in compliance with the relevant on and offshore legislation, industry guidance and company requirements.

With this in mind, this chapter has been generated to give an understanding of how the RBI assessment process works by identifying the consequences and the likelihood of failure. Once identified these consequences and likelihoods can provide a basic risk based ranking functionality to determine the frequency of examination for topside and subsea process and piping systems. This includes a qualitative analysis that allows for the prioritizing of the pressure systems within a five by five matrix, which rates them from lower to higher risk, which in turn can be used to identify high risk areas that may require further risk analysis. Before starting any RBI assessment there are certain things that need to be in place.

As a minimum the following roles shall be consulted and/or actively take part in a RBI Assessment process, as appropriate:

- Inspection Engineer
- Integrity Engineer
- Materials/Corrosion Engineer
- Chemical Representative
- Process Engineer
- Operations Representative(s)
- Risk Advisor

Note that certain team members may be part-time due to limited input needs. It is also possible that not all the team members may be required if other team members have the required skills and knowledge of that discipline. As a result, it is necessary to document the skills/qualifications of the RBI Assessment Team. Due to potential demand on individuals' time, the RBI Coordinator will prepare as best he/she can in advance of all meetings with the aim to maximizing individuals focus and minimizing individuals' meeting time.

RBI Coordinator: The RBI Coordinator will lead and coordinate the team. Providing the person assigned to this role is knowledgeable in the RBI process, this role can be a dual role completed by the Inspection Engineer, the Materials/Corrosion Engineer or the Integrity Engineer. The RBI Coordinator should also be a full-time team member, and shall be responsible for:

- Preparing information for RBI meetings;
- Leading and guiding the team and chair meetings;
- Verifying, through quality checks, the soundness of data and assumptions;
- Verifying that team members have the necessary skills and knowledge and that part time members are consulted as required;
- Preparing a report on the RBI study and distributing it to the appropriate personnel whom are either responsible for decisions on managing risks or responsible for implementing actions to mitigate the risks;
- Supporting the Liaison with regulatory authorities, as required;

The RBI Coordinator shall have a thorough understanding of risk analysis, either by education, training, or experience.

Inspection Engineer: The Inspection Engineer is a core team member responsible for:

- Gathering data on the condition of equipment in the study. This condition data should include the new/design condition and current condition. Generally, this information will be located in equipment inspection files and an equipment integrity database. If condition data is unavailable, the Inspection Engineer, in conjunction with the Materials/Corrosion Engineer, should provide predictions of the current condition;
- Assessing the effectiveness of past inspections;
- Implementing the recommended inspection plan derived from the RBI study.
- Advising Integrity Engineer when appropriate risk mitigation actions have not been implemented.

Integrity Engineer: The Integrity Engineer is a core team member who is accountable for the RBI process and is required to:

- Ensure the recommended risk mitigation actions derived from the RBI study are implemented;
- Ensure inspection intervals are not exceeded;
- Ensure resources are available for RBI Assessments; and,
- Liaise with Regulatory Body and Certifying Authority, as required.

Materials/Corrosion Engineer: The Materials/Corrosion Engineer is a core team member responsible for the following:

- Actively participate in all meetings;
- Identify reason(s) for differences between predicted and actual equipment condition, and provide guidance on degradation mechanisms and rates of deterioration to be used in the RBI study; and,
- Recommend methods of mitigating the probability of failure (e.g. changes in metallurgy, addition of chemical inhibition, chemical sampling, corrosion monitoring, addition of coatings/linings, etc.) and evaluate appropriateness of risk mitigation strategies in relation to degradation mechanisms.

Chemical Representative: Where possible a representative from the Process Chemical supplier should be present. This person is accountable for providing information regarding the various chemical programs that are used to mitigate corrosion (biocides, corrosion inhibitors, oxygen scavengers, etc.). Furthermore, this person is responsible for providing information regarding the monitoring of the respective programs. In the event that a process chemical representative cannot be present, the Materials/Corrosion Engineer shall be responsible for obtaining this information.

Process Engineer: The Process Engineer is a core team member, responsible for the provision of process engineering support including:

- Highlight variations in process conditions due to normal occurrences (e.g. startups and shutdowns), abnormal occurrences and potential changes due to future operating conditions (e.g. introduction of new wells, increased water cut, increased GOR, souring of reservoir, etc.);
- Describe the composition and variability of all process fluids/gases as well as their toxicity and flammability; and,
- Evaluate/recommend methods of risk mitigation through changes in process conditions or through process monitoring.

Operations Representative(s): The Operations Representative(s) is a core team member from either the production or marine department where relevant. The individual(s) shall be knowledgeable of plant operations and responsible for the following:

- Verify that the facility/equipment is being operated within the parameters set out in the process conditions;
- Provide data on occurrences when the process deviated from the limits of the process condition;
- Develop credible limiting consequence scenarios for failure modes under consideration;
- Implement recommendations that pertain to process or equipment modifications;
- Provide input with respect to shutdown impacts of equipment (i.e. system shutdown, plant shutdown, etc.); and,
- Verify that equipment repairs/replacements/additions have been included in the equipment condition data supplied by the Inspection Engineer.

Risk Advisor: The risk advisor may be a part-time team member, responsible for:

- Quantitative Risk Assessment (QRA) and Safety Study review where relevant;
- Provide interpretation on Risk Management issues and the Risk Matrix. Generally, this individual is consulted on the consequence of failure assessment.

Training: All team members shall have basic training in RBI assessment methodology. The training shall be geared primarily to an understanding of RBI procedures. The training may be provided by the Risk Assessment Personnel on the RBI Team or by a person knowledgeable in RBI methodology.

Typical data needed for a RBI analysis includes, but is not limited to, the following:

- Equipment Datasheets and construction drawings
- Materials of construction
- Inspection, repair and replacement records
- Process fluid compositions (Volumes, Flowrates, Pressure, Temperature, pH, etc)

- Process Chemical program monitoring
- Degradation mechanisms, rates and severity
- Coating, cladding, lining and insulation data
- Operating practices (i.e.: duty versus standby, in-service versus laid up, etc)
- Personnel densities
- Repair or Equipment Replacement Cost,
- Business interruption cost
- Environmental remediation costs

Risk Assessment Process

The integrity management process, including inspection and maintenance planning, is not a one-time activity but a continuous process where information and data from the inspection/maintenance/monitoring activities are fed back into the planning and strategy development.

Periodic reviews are undertaken in the light of the inspection, monitoring and maintenance history gathered during the inspection execution phase. The purpose of these periodic reviews is to ensure that:

- any new items of equipment are identified and included in the inspection strategy
- the internal and external design conditions anticipated in the original risk assessment remain valid
- the original criteria set for the consequences remain valid
- actual degradation rates as measured are not exceeding the predicted degradation rates

The integrity management process is also iterative in nature. The output of the inspection and monitoring activities are fed back into the integrity management cycle and the risks (and consequently the strategies) are reviewed in the light of the inspection and monitoring history. The results from the integrity management process can also be used to drive improvements to future projects and to equipment reliability by applying lessons learned.

The first requirement of any integrity management strategy is to clearly define the extent of the system down to inspection component level. This is done for the avoidance of doubt and also to ensure that all the critical components within the system are captured in the integrity management strategy. Where new equipment is installed or equipment is decommissioned, it should be a part of the management of change process so that the integrity management strategies affected by the change are reviewed and updated accordingly. This requires input from projects and operations review teams. The incorporation of new equipment into the integrity management strategies is best done prior to the project handover stage.

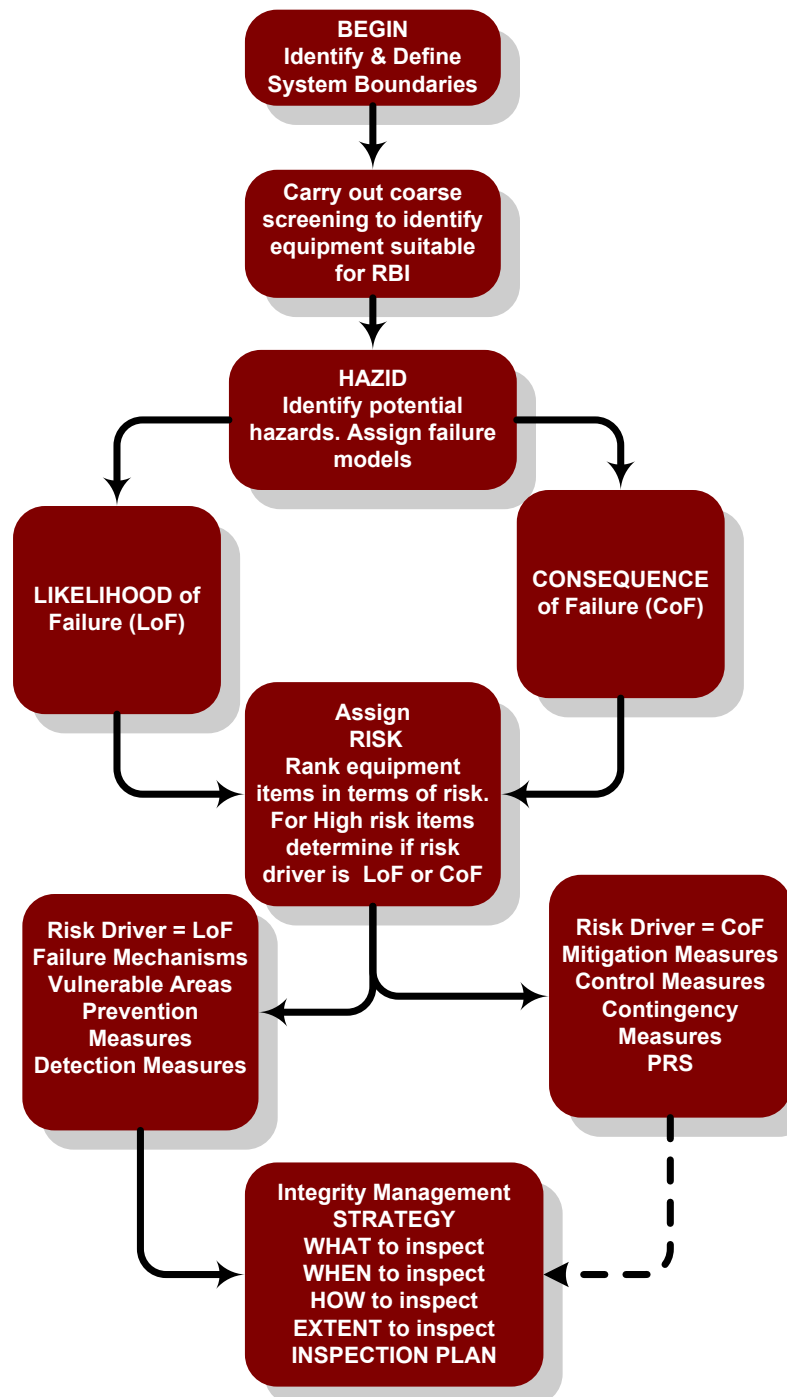
The purpose of applying a risk based approach to integrity management and inspection planning is to focus the inspection effort on the high-risk equipment items. A risk based inspection strategy should identify all relevant damage and degradation mechanisms for each piece of equipment being risk assessed. Based on this information, the most appropriate inspection/monitoring method can be chosen and a suitable inspection/monitoring frequency will be defined.

In summary, a risk based inspection management system addresses four fundamental questions:

- What equipment items should be inspected?
- What is an appropriate inspection frequency?
- What is/are the appropriate method(s) of inspection?

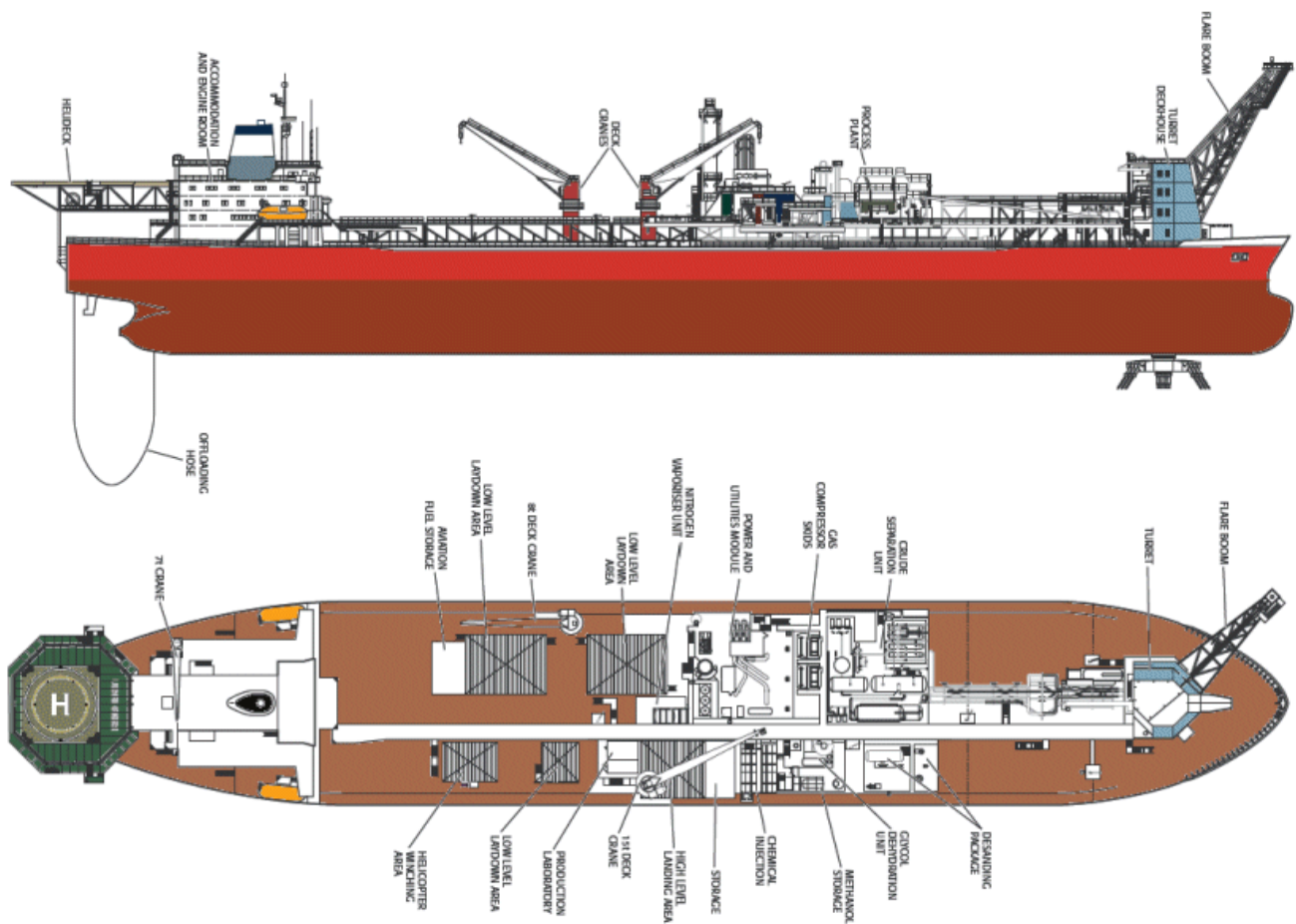
· What is an appropriate level or extent of inspection?

The process followed in the development of a risk based integrity management strategy is shown in the following figure.

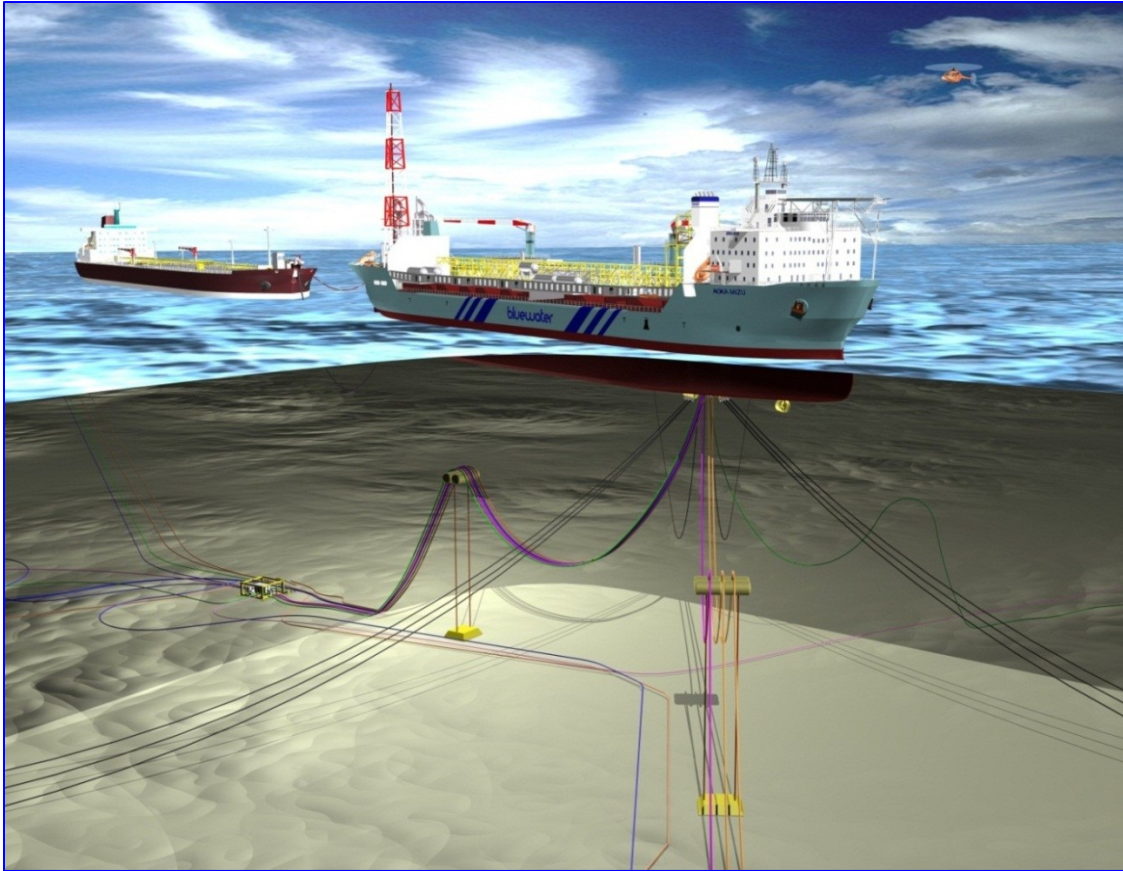


Process Flow for Risk Based Integrity Management System

On an offshore facility, the most obvious distinction of system limits is that between the equipment located on and above the water and the equipment located below the water. A further distinction is made between items whose purpose is primarily supporting structure and equipment item whose purpose is the containment of fluid. Within this latter category a distinction is drawn between the internal (exposed to the transported fluids) and external environments. Within these system boundaries the sub systems and components are then defined. The component definitions can be found in the relevant system integrity management strategies. Not all equipment that is located under water falls within the realm of the subsea integrity management strategies, for example the integrity management of various components associated with an FPSO hull, the turret and the mooring system will come under the vessel's Class Society rules. Eg, American Bureau of Shipping, Det Norske Veritas, Lloyd's Register of Shipping etc. Effectively an FPSO is a "permanently" moored ship and subject to the normal ship rules. Not all FPSOs will be specifically designed for that function. Many are converted tankers.

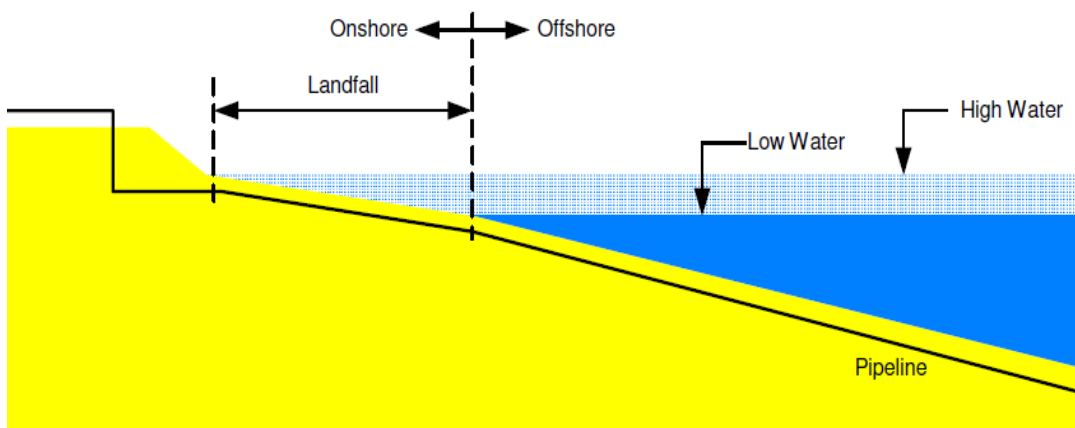


Typical FPSO layout



Subsea production using FPSO

For pipelines passing from offshore to onshore, it is necessary to clearly define the demarcation between the two areas. The most common system in use is the mean low water mark or, in non-tidal areas, the mean water level (as shown in following figure).



Pipeline limits - Landfall

Hazard Identification (HAZID)

The initial qualitative risk assessments (sometimes referred to as an Engineering Criticality Assessment) carried out for the facilities firstly identified the systems, subsystems and components comprising the subsea facilities. The hazard identification process identified that loss of containment and/or loss of structural integrity could occur as the result of:

- Internal corrosion
- Erosion
- External corrosion
- External mechanical damage
- Structural over stressing
- Hydraulic overpressure

The hazard identification (HAZID) process relies on knowledgeable individuals contributing their experience and judgments to the process. Where conventional and established technologies and materials are being assessed, the failure mechanisms associated with such technologies and materials are usually well understood and documented. However in the case of new and emerging technologies and materials, or those with a limited history of field applications the potential failure mechanisms will have been derived from laboratory test and empirical data. It is important that the results of the in-service inspections and monitoring activities pertaining to such materials and items are frequently reviewed. This is to ensure that the materials are behaving in the in-service environment as predicted by the laboratory results.

It is usually desirable to list all the potential failure mechanisms that could occur and subsequently screen out those which are considered unlikely or otherwise inappropriate of further consideration. Applying a “what if...” approach increases the potential for capturing all the potential failure mechanisms. This approach to hazard identification (HAZID) can be formalized using techniques such as the HAZOP (Hazard and Operability Study) where guidewords are used to structure the discussions of the hazard identification team. All the hazards assessed should be recorded so that they too can be periodically reviewed in the light of the in service data and operational experience.

Consequence Assessment

In the risk assessment process the consequence of a particular event is assessed in term of the overall adverse effects the event could have on personnel (safety), the asset / facility and other equipment loss, the environment or system operability. The term operability is used as a measure of the consequence a failure would have on production, both in terms of immediate production loss and the long-term effects on production while a repair is carried out. The following table is a typical consequence assessment.

Consequence Rating	Consequence Factor			
	Safety (S)	Environment (E)	Production (P)	Business (B)
Very Low (Negligible)	No injury to personnel	No Harmful release or environmental consequence	Minimal loss of production / drilling operations	Slight equipment damage, repair cost or increase in OPEX (<\$1,000) No impact on plan
Low (Marginal)	Slight injury resulting in First Aid Case	Minor release/contained spill localized and contained within site boundaries	Minor downtime or less than 6 hrs total loss of production / drilling or total production loss exceeding 1,000 boe	Minor system damage, repair cost or increase in OPEX (\$1,000<\$10,000) impact on plan, delay <1 month
Medium (Moderate)	Minor personnel injury impact or illness. Affects work performance	Moderate release of harmful substances with possible widespread effect Increased flaring	Moderate downtime or 0.25 -1 days total loss of production / drilling or total production loss exceeding 5,000 boe	Moderate system damage, repair cost or increase in OPEX (\$10,000<\$100,000) Impact on plan, delay <1 month
High (Critical)	Severe personnel injury or disability. Degraded function of Safety Critical Equipment	Uncontained release of hazardous substance Breach of flaring limits	Major downtime or 1-10 days total loss of production / drilling or total production loss exceeding 25,000 boe	Major system damage or increase in OPEX (>\$100k<\$1,000,000) Impacts plan, delay 1 month < 3months
Very High (Catastrophic)	Fatality(s) Loss of function of Safety Critical Equipment	Large uncontained release of hazardous substance Prosecution for breach of flaring limits	Extended downtime or more than 10 days total loss of production / drilling or total production loss exceeding 100,000 boe	Extensive damage, repair costs or increase in OPEX (>\$1,000,000) Impacts plan, delay >3 months

Consequence of Failure Assessment Criteria

Note:

boe – Barrel of Oil Equivalent = 1.7MWh

The next thing to assess is the likelihood of an event occurring. The following table is typical of the criteria used.

Likelihood Rating	Definition
Very Low	Mean Time Before Failure (MTBF) > 30 years Failure not foreseeable under normal operating conditions within the remaining life of the asset
Low	Mean Time Before Failure (MTBF) > 10 years but < 30 years Failure possible within life of asset, based on knowledge of construction materials and service conditions
Medium	Mean Time Before Failure (MTBF) > 5 years but < 10 years Failure probable within life of asset, based on knowledge of construction materials and service conditions
High	Mean Time Before Failure (MTBF) < 5 years High probability of failure within life of asset, based on knowledge of construction materials and service conditions
Very High	Mean Time Before Failure (MTBF) < 2 years Very high probability of failure within life of asset, based on knowledge of construction materials and service conditions

Likelihood of Failure Assessment Criteria

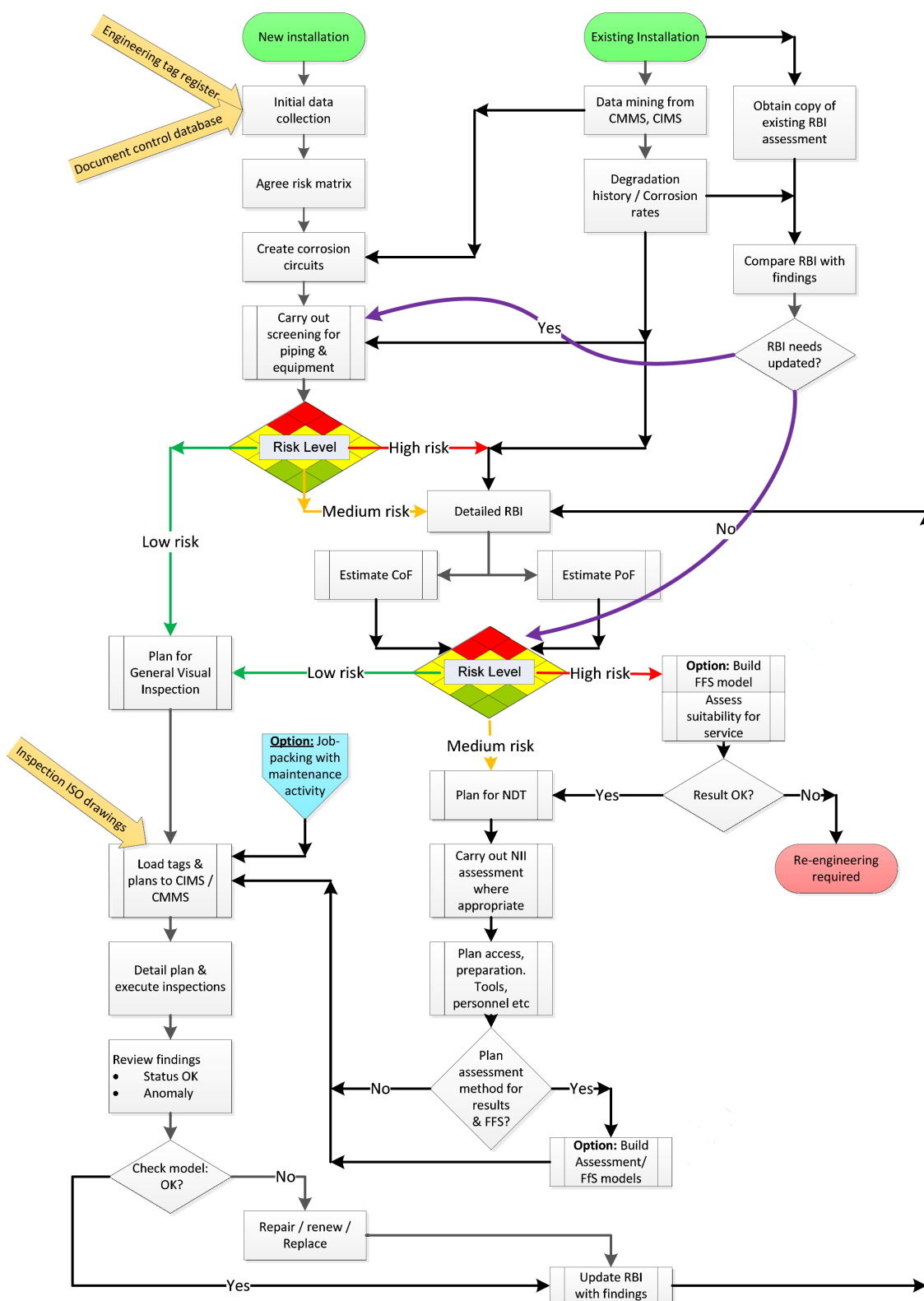
Putting the Consequence and Likelihood tables together gives us a Risk Matrix. The following is typical:

	Consequences				
Likelihood	Negligible	Marginal	Moderate	Critical	Catastrophic
Very High	MEDIUM (5)	MEDIUM (6)	HIGH (7)	HIGH (8)	HIGH (9)
High	LOW (4)	MEDIUM (5)	MEDIUM (6)	HIGH (7)	HIGH (8)
Medium	LOW (3)	LOW (4)	MEDIUM (5)	MEDIUM (6)	HIGH (7)
Low	LOW (2)	LOW (3)	LOW (4)	MEDIUM (5)	MEDIUM (6)
Very Low	LOW (1)	LOW (2)	LOW (3)	LOW (4)	MEDIUM (5)

Risk Assessment Matrix

This Risk Matrix is used to adjust inspection intervals, for a given overall risk rating, based on current knowledge of equipment condition, and predicted future performance in service. When used properly RBI and Risk Matrix protocols can provide a robust, conservative approach to defining equipment status in terms of past inspection scope and strategy effectiveness, stability of process conditions and suitability of equipment for service. However, it cannot be emphasized too strongly that the old computer maxim; GIGO holds very true for RBI and that is: Garbage In – Garbage Out!

Overall RBI Process



Typical RBI Scope of Work

Phase 1 – High Level Review

The High Level Review (Phase 1) would normally comprise of a system level integrity assessment of all process and utility systems. The aim of this high level assessment is to identify low criticality systems that could be omitted from the subsequent detailed RBI scope. The main information and data sources used in this system level integrity assessment should include:

- Process Flow Diagrams (PFDs) and Piping and Instrumentation Diagrams (P&IDs)
- Piping specifications
- Design philosophies
- Heat and material balances
- Historical inspection data

Phase 2 – Detailed RBI Assessment

Based on the initial high level review recommendations are given as to which aspects are to be incorporated into the execution of the detailed RBI scope of work: for example:

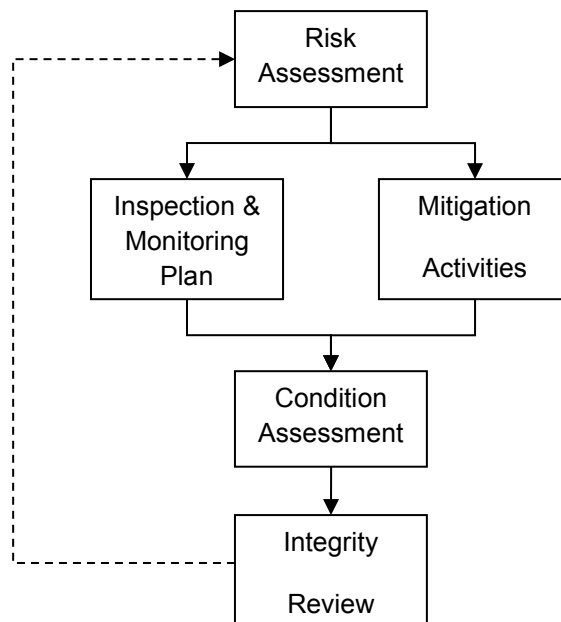
- Project Basis:
 - Detailed RBI to focus on high and medium risk systems.
 - No analysis of low risk systems, but requirements for integrity management, identified from high level review, to be confirmed.
- Project Execution:
 - High and medium risk systems (where appropriate) to be broken down into constituent vessels/components and corrosion loops (piping)
 - Prioritized systems to undergo semi-quantitative risk assessment consistent with the principles of API RP 580
 - Credible failure modes to be identified for each vessel / heat exchanger and corrosion loop
 - Effect of failure modes on vessel or corrosion loop functionality to be identified
 - Facilitated risk assessment process to determine likelihood and consequences of failure for each failure mode
 - Relative risk rating for each vessel, corrosion loop or system to be determined according to Criticality Assessment Matrix
 - Any failure modes associated with a low risk of failure to be discounted from further assessment providing justification can be made
 - A thorough assessment to be made of integrity management options for failure modes associated with high and medium risk
 - Integrity management options to include inspection, corrosion monitoring, process monitoring, chemical treatment, fluids analysis, microbial sampling, etc
 - Frequency of integrity management activities to be identified and controlled through an appropriate matrix to be agreed
 - Detailed integrity management strategies to be formulated for each vessel / heat exchanger and corrosion loop, as required

- Deliverables:
 - High and medium risk systems (where appropriate) to be broken down into constituent vessels/components and corrosion loops (piping)
 - Marked up P&IDs showing breakdown of systems at vessel and corrosion loop level
 - Detailed integrity management plan for high and medium risk vessels, corrosion loops and systems. To include system/loop level inspection and monitoring requirements; intervals, techniques and scope of coverage.

The High and Medium Criticality systems are normally selected for detailed assessment at equipment and corrosion loop level.

RBI Programme Sustainability

Once established, it is essential to keep the RBI programme fully up-to-date by ensuring that the equipment risk and condition assessments are re-evaluated as required by the results of integrity management activities. The ongoing RBI management process is outlined below.



RBI Management Process

Following completion of the relevant inspections and collation of any corrosion or process monitoring data, an evaluation of the current condition of equipment and corrosion loops is undertaken. This will take into consideration the range of mitigation activities applied. The condition assessment may also involve the application of standardized approaches to defect assessment and fitness-for-service analysis using ASME VIII, ASME B31.3, API 579, etc.

A critical component of the RBI process is the Integrity Review. In the long term, this enables equipment criticality assessments to be reviewed and verified against actual plant experience. Accordingly, inspection,

monitoring, testing and mitigation activities may be modified to account for the current equipment condition and anticipated future service conditions.

Once established through the initial risk assessments, inspection/monitoring and mitigation plans, the RBI process operates through a feedback mechanism so that relevant inspection, monitoring, testing and operational data is evaluated as required, and integrity management plans updated as appropriate.

Integrity Review

The Integrity Review stage will cover all of the elements that affect equipment criticality, including:

- Verification of plant materials data
- Equipment process and operational data/history
- Potential changes in use affecting consequences of failure
- Credible failure mechanisms
- Relevant inspection and monitoring data

The objectives of the Integrity Review are:

- To establish the actual condition of equipment and its fitness-for-service
- To establish the observed deterioration mechanisms and rates
- To establish the level of confidence in the predictability of the deterioration rate and, hence, the current condition of the equipment
- To determine the requirements for equipment rehabilitation and failure mitigation, including repairs and fabric maintenance
- To reassess equipment criticality based on current condition and predicted performance
- To determine the future requirements for inspection, monitoring and mitigation activities consistent with the revised assessment of equipment criticality

The Integrity Review will form the basis of long-term management of the RBI process. The verification of inspection and operating data provides a critical feedback loop, vital for the successful implementation of RBI, as it provides the justification for managing risks to a level commensurate with business and safety requirements. This includes defining the optimum balance between on-stream and off-line maintenance, and how preventive maintenance is complemented by turnarounds and overhauls to ensure continued fitness for purpose and integrity for operation.

Required attendees for Integrity Review meetings include the Pressure Systems Integrity Engineer, Corrosion Engineer, Inspection Engineer and Facilities Engineer to ensure that all relevant aspects are covered and that risk assessment and confidence level decisions are made in a timely, consistent manner.

Integrity Review Interval

The optimum scheduling of Integrity Reviews is largely dependent on whether all inspection activities are confined to a specific 'inspection campaign' period or 'window', or whether they are carried out according to specific due dates throughout the calendar year. Assuming the inspection programme follows the latter route, Integrity Review meetings could be scheduled at any time. The meeting should aim to address the key

objectives highlighted above for each static equipment item and corrosion loop. In addition, if limited data is available for the initial RBI assessment, the meetings should aim to establish the normal operating envelope for the items under review.

Inspection Strategy

The objective of the inspection strategy for each equipment item will be to address all credible failure modes, with the scope and level of detail determined by the risk rating. In most circumstances this will result in a limited range of inspection strategies, dependent upon equipment type, deterioration mode and expected rate (time dependent mechanisms, e.g. general corrosion) or initiation conditions (stochastic mechanisms, e.g. stress corrosion cracking).

Although there are a wide range of specialist techniques that can be used to identify specific degradation mechanisms, most external and internal corrosion/materials degradation issues can be identified using a small range of relatively low cost and well understood methods. The majority of planned inspections will therefore be carried out using:

- Visual examination and routine metrology
- Ultrasonic wall thickness and crack-sizing measurements
- Liquid crack detection (e.g. dye penetrant testing, magnetic particle inspection)

The use of inspection techniques to evaluate unanticipated or highly improbable failure modes should not be required, although there may be occasions where such speculative examination may be beneficial (e.g. for equipment operating in unusual environments or process conditions). In general the deployment of specialist techniques can be very expensive, and there may be logistical constraints when applied to the facilities. Therefore, the use of specialist inspection techniques will be restricted to situations where there is either:

An identified threat of failure and no-cost effective alternative method of inspection

or

A clear cost-benefit and technical advantage has been demonstrated over conventional inspection methods.

Traditionally most major inspection activities relating to static equipment have relied on thorough internal inspections, where access permits. This requires considerable planning and issuing of permits due to the need for complete isolation of the equipment, venting, draining, cleaning/purging and subsequent man-entry and associated safety protection systems.

Providing that full access into the equipment is possible, the inspector will deploy a range of inspection methods, in addition to visual examination, consistent with the range of credible failure modes anticipated for the equipment.

Where access is restricted due to, for example, the absence of appropriate man ways, the use of “head and shoulders” visual examination is to be discouraged. This approach can be highly subjective and may offer only limited value in terms of equipment confidence level.

It should be noted that the health & safety aspects, quality and effectiveness of internal visual examinations may be improved by the application of potentially less subjective techniques such as the borescope. The use of high

quality borescopes in combination with video recording/image capture equipment can be used to increase the confidence in visual examination data by providing permanent, verifiable records of equipment condition. This methodology has the potential to substantially reduce the costs and risks associated with invasive inspections, as full isolation, purging and man-entry would no longer be absolutely necessary. This approach will be particularly suited to columns and other vessels containing complex internals or other physical restrictions.

Baseline Inspections

It is normally recommended that for new facilities a baseline inspection is carried out within one year of operational startup. The main objectives of this survey will be:

- To obtain early assurance of the HIGH and MEDIUM criticality equipment integrity and provide a reference for future assessments of degradation.
- To provide baseline wall thickness readings for piping corrosion loops and static equipment (as appropriate).
- To identify any potential corrosion 'hot spots' or unanticipated deterioration modes.
- To identify any issues regarding access to areas of potential degradation e.g. scaffolding requirements, inability to carry out adequate external inspections.
- To identify any potential integrity concerns arising from plant lay out, positioning or initial operations.

Baseline Survey Scope – Static Equipment

Baseline inspections for HIGH criticality equipment should comprise a close visual external examination, combined with application of Non Intrusive Inspection (NII) techniques suitable for wall thickness gauging and the detection of credible failure modes. Baseline inspections for MEDIUM Criticality equipment should comprise of general visual external examination, supplemented by spot wall thickness checks on equipment where internal corrosion mechanisms have been identified as credible failure modes within the life of the facility.

The key mechanisms are the most likely degradation mechanisms for each item of equipment based upon the detailed risk assessment. Evaluation of these mechanisms will be addressed as part of the baseline inspection workscope for each equipment item.

The main objective will be to try to confirm the overall vessel wall thickness. Ultrasonic thickness (UT) measurements taken from internally coated vessels should confirm whether and corrosion or materials degradation has occurred under disbonded or damaged coating materials.

All thickness measurement locations (TMLs), wall thickness mapping requirements and requirements for other specific inspection techniques should be identified on static equipment general arrangement drawings.

Baseline Survey Scope – Piping

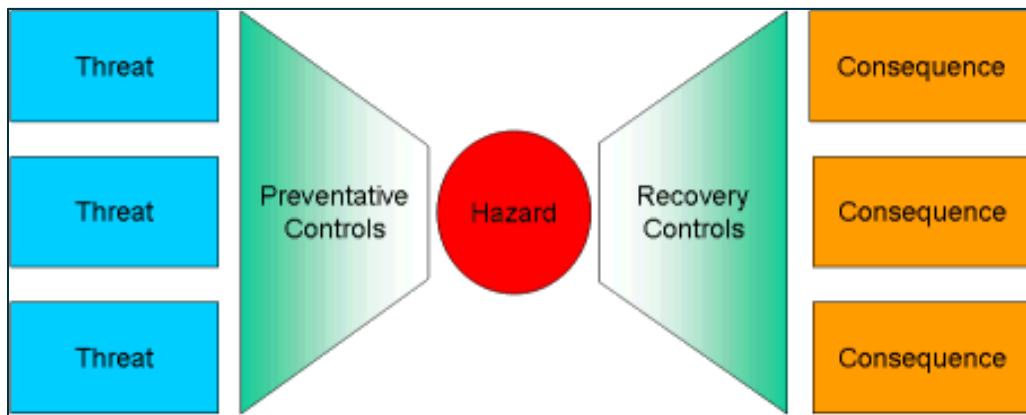
Baseline survey requirements for corrosion loops (Piping) which involve a *corrosion rate assessment*, will be based on ultrasonic wall thickness measurements taken at specific locations (TMLs) identified on piping

isometrics. For HIGH Criticality corrosion loops this will be based on numerous TMLs covering a range of pipe diameters. Thickness measurements on MEDIUM corrosion loops will be taken from a limited number of TMLs.

External Corrosion Mechanisms will be evaluated as part of the close visual or general visual external examination of piping. In addition, if it is the intention to use methods such as Long Range Ultrasonic Technology (LRUT) in the future then it would be beneficial to obtain a baseline 'Footprint' at this time.

Bowtie Analysis

Another method of risk assessment which has found favor in the last few years is called the Bowtie Analysis. The exact origins of Bowtie methodology are hazy although it is believed to originate from ICI in the late 1970's and that in the early nineties the Royal Dutch / Shell Group adopted the Bowtie method as a company standard for analysing and managing risks. Shell facilitated extensive research in the application of the Bowtie method and developed a strict rule set for the definition of all parts, based on their ideas of best practice. The primary motivation of Shell was the necessity of assurance that appropriate risk controls are consistently in place throughout all worldwide operations. Use of Bowties is now widely spread between companies, industries, countries and regulators.

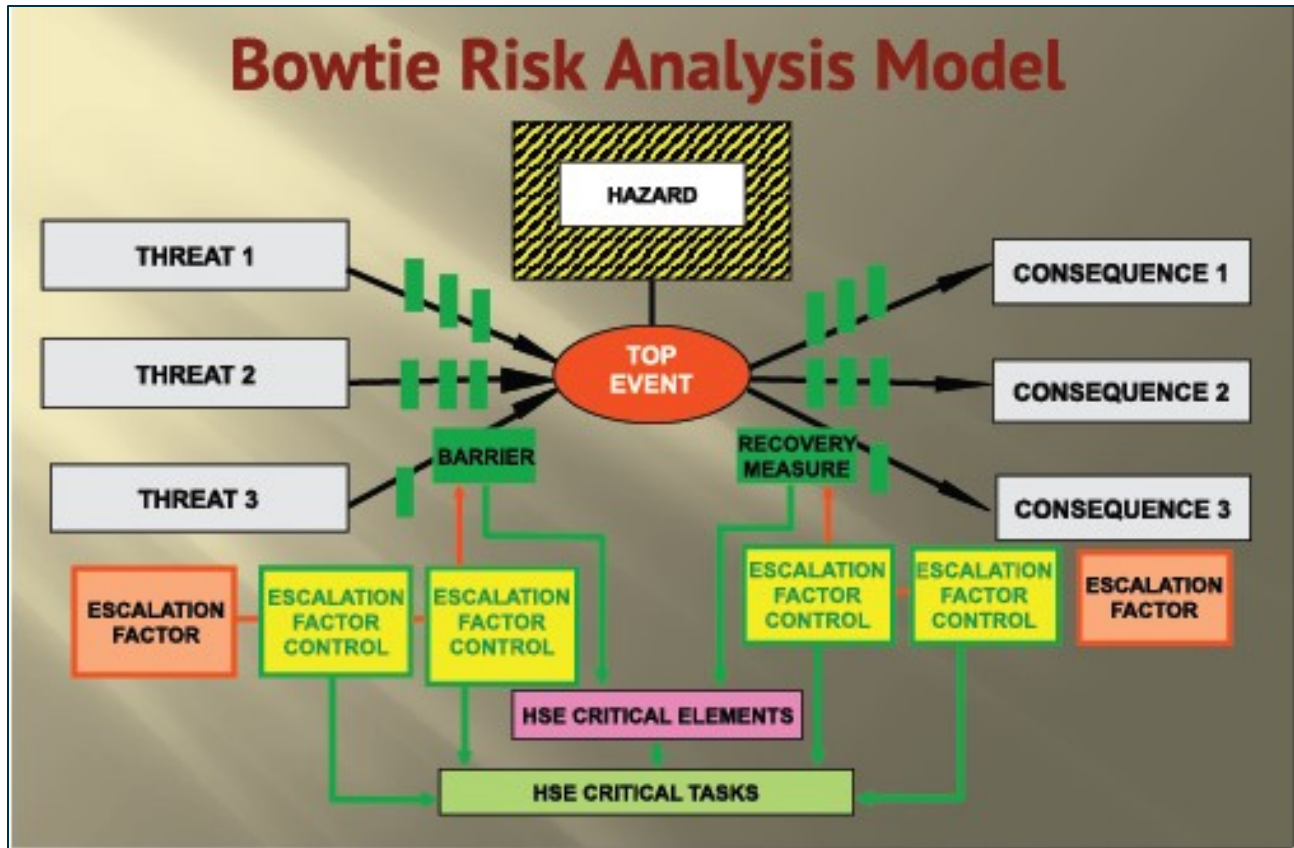


Simple Bowtie diagram

The Bowtie method is a risk evaluation method that can be used to analyze and demonstrate causal relationships in high risk scenarios. Unlike traditional risk evaluation tools, the bow-tie method makes the link between risk controls and Health, Safety and Environmental considerations. The method takes its name from the shape of the diagram that is created, which looks like a man's bowtie. A Bowtie diagram does two things. First of all, a Bowtie gives a visual summary of all plausible accident scenarios that could exist around a certain Hazard. Second, by identifying control measures the Bowtie displays what a company does to control those scenarios.

However, this is just the beginning. Once the control measures are identified, the Bowtie method takes it one step further and identifies the ways in which control measures fail. These factors or conditions are called Escalation factors. There are possible control measures for Escalation factors as well, which is why there is also a special type of control called an Escalation factor control, which has an indirect but crucial effect on the main Hazard. By visualizing the interaction between Controls and their Escalation factors one can see how the overall system weakens when Controls have Escalation factors.

Besides the basic Bowtie diagram, management systems should also be considered and integrated with the Bowtie to give an overview of what activities keep a Control working and who is responsible for a Control. Integrating the management system in a Bowtie demonstrates how Hazards are managed by a company. The Bowtie can also be used effectively to assure that Hazards are managed to an acceptable level (ALARP)

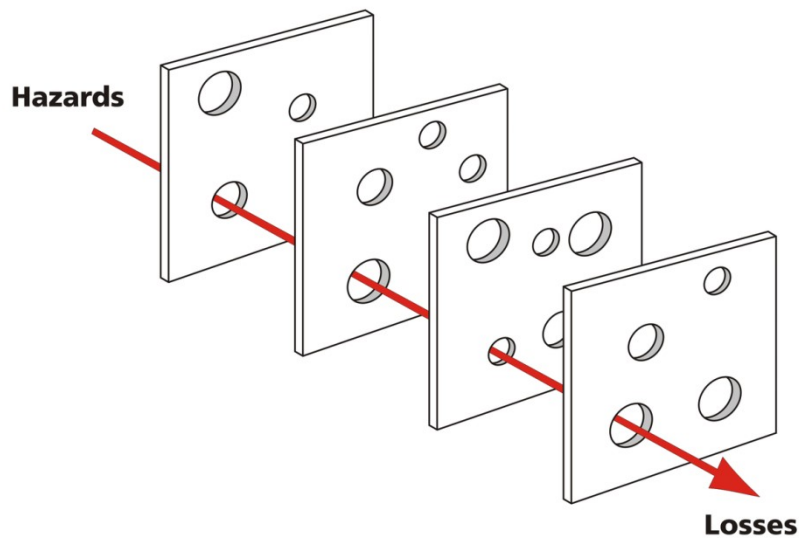


Detailed Bowtie Analysis

By combining the strengths of several safety techniques and the contribution of human and organizational factors, Bowtie diagrams facilitate workforce understanding of Hazard management and their own role in it. It is a method that can be understood by all layers of the organization due to its highly visual and intuitive nature. This gives it certain advantages in that the graphical representation the Bowtie diagram can give a clear picture of what are often complex safety management systems and also clear links between management systems and safety are shown. The downsides, however, are that Bowtie analysis requires a high level of knowledge regarding a system and the components of the system that relate to its safety and that it is difficult to link to quantitative techniques.

Swiss Cheese Model of Accident Causation

Another concept in risk analysis worth considering is the Swiss Cheese Model of Accident Causation. Sometimes called the cumulative act effect, it illustrates that, although many layers of barriers lie between hazards and accidents, there are flaws in each layer that, if aligned, can allow the accident to occur.



Swiss Cheese Model of Accident Causation

Every step in a process has the potential for failure, to varying degrees. Each of the slices can be considered as defensive layers or safety barriers in the process. The holes are analogous to opportunities for that process to fail. An error may allow a problem to pass through a hole in one layer, but in the next layer the holes are in different places, and the problem should be caught. For a catastrophic failure to occur, the holes in each step of the process need to align with those before and after them allowing all defenses to be defeated and resulting in a failure of the system. If the layers are set up with all the holes lined up, this is an inherently flawed system that will allow a problem at the beginning to progress all the way through to adversely affect the outcome. Each slice of cheese is an opportunity to stop an error. The more defenses you put up, the better. Also the fewer the holes and the smaller the holes, the more likely you are to catch/stop errors that may occur.

Non-Invasive Inspection

In recent years the increasing application of RBI has been used to support more flexible and operationally efficient inspection strategies. For example, the application of comprehensive, non-invasive inspection strategies can be used to increase plant availability by reducing the requirement for “inspection-driven” equipment downtime. The use of non-invasive methods can reduce the general health and safety risks posed by blowing down, purging equipment and vessel entry. Furthermore, these methods can also reduce the integrity threat associated with taking equipment out of service and exposing it, albeit temporarily, to ambient, potentially corrosive environments.

Non-Invasive Inspection (NII) is often referred to as an inspection performed from the outside of the vessel without having to break containment and/or not requiring vessel entry. It may be performed on-stream or off-stream. There are many alternative methods within NII, where the preferred method depends on factors like vessel geometry, materials, deterioration, location etc.



Thermal image of De-Salter vessel showing water intrusion under the insulation

One of the “bibles” on NII is the freely available DNV guidance notes (DNV-RP-G103). It lists 11 different NII methods. Many of these will be described later.

1. Ultrasonic Testing
2. Radiography
3. Liquid Penetrant
4. Eddy Current Testing
5. Magnetic Particle Inspection
6. Magnetic Flux Leakage
7. Thermography
8. Backscatter or Compton Imaging
9. Acoustic Emission
10. Remote Visual Inspection
11. Shearography

Why NII?

Pressure vessels and systems undergo periodic, statutory and other testing to ensure continued safe and reliable operation. Stopping operations for inspection can have a significant time and cost impact, as well as adding additional risks. The reasons for NII include;

- To replace internal visual inspections
- To postpone internal visual inspections
- To inspect internal areas that is hard to access internally (i.e. because of internal equipment)
- To give status of vessel as part of planning entering

In addition it has numerous Health, Safety and Environmental benefits. One is that man access may be hazardous and present environmental risks. In traditional inspection, a specialist must physically enter the vessel to perform inspection. Lastly, mechanical disturbances involved in traditional turnarounds may adversely affect future performance of the vessels.

An example of the potential benefits for NII was a test done on a pressure vessel on a platform on the Northern Continental Shelf. An NII analysis was performed on a vessel that had traditionally had an internal inspection every other year. The NII concluded that the necessary internal inspection could be postponed to every 3rd year. This resulted in a considerable saving in terms of time and money.

In other words, there are significant advantages if inspections are performed from the outside of the vessel without breaking containment i.e. non-invasively.

One of the main advantages of a successful RBI approach is that it identifies the failure mechanisms likely to affect equipment based upon the anticipated range of operating conditions. By matching the credible failure mechanisms and locations to appropriate inspection techniques, it is possible to generate equipment specific, non-invasive inspections that can match the effectiveness of invasive inspections

The acceptance of non-intrusive inspection strategies requires that they are capable of at least achieving the same detection and sizing requirements as detailed intrusive inspections. This may be in the form of results from both previous intrusive and non-intrusive inspections showing good correlation, or a verifiable report on the capability of the non-intrusive inspection which can be compared with previous intrusive results. The application of non-intrusive methods is particularly suited to corrosion mapping and crack detection in simple pressure vessels, drums and storage tanks.

Alternatively, non-intrusive inspection can be applied in addition to a detailed intrusive inspection prior to an outage and during short shutdowns to assist in the planning of detailed intrusive internal inspections. In addition, non-intrusive methods can be used to provide immediate information on an identified potential problem with the minimum of interference with other operations.

Inspection and Monitoring

This section is really only a “quick and dirty” overview of various inspection methods. The reference section at the end of the book gives a number for resources with far greater detailed explanations and examples.

Visual Inspection

Visual inspection (VT) relies upon the detection of surface imperfections using the eye. Normally applied without the use of any additional equipment, VT can be improved by using aids such as a magnifying glass or strong light source. VT is considered to be the primary NDT method. Since it relies on an evaluation made using the eye, VT is generally considered to be the primary and oldest method of NDT.

With its relative simplicity and because it does not require sophisticated apparatus, it is a very inexpensive method thus provides an advantage over other NDT methods. A further advantage of VT is that it is an ongoing inspection that can be applied at various stages of construction.

The primary limitation of VT is it is only capable of evaluating discontinuities which can be seen on the surface of the material or component. Sometimes there may be some visual indication of a subsurface imperfection that may need an additional NDT method to provide verification of the subsurface discontinuity. VT is most effective

when it is performed at all stages of any new fabrication, and is the main method used during the inspection of pressure equipment.

If applied say after welding has been completed, it is possible that subsurface flaws may not be detected. Therefore, it is important to appreciate that VT will only be fully effective if it is applied throughout any fabrication or inspection. An effective VT programme if applied at the correct time will detect most defects or discontinuities that may later be found by some other costly and time consuming NDT method. The economics of VT can be seen in welding if we consider how much easier and inexpensive a welding problem can be corrected when found at the right time, i.e. as it occurs.

For example, a flaw, such as incomplete fusion at the weld root, can be repaired easily and quickly right after it is produced, saving on expense and time required repairing it after the weld has been completed and inspected using some other NDT technique.

VT will also give the technician instant information on the condition of pressure equipment regarding such things as corrosion, bulging, distortion, correct parts, failures, etc.

VT requires three basic conditions to be in place. These are:

- good vision, to be able to see what you are looking for
- good lighting, the correct type of light is important
- experience to be able to recognize problems.

As mentioned previously, one of the advantages of VT is that there is little or no equipment required, which improves its economy or portability. Equipment, which may be employed to improve the accuracy, repeatability, reliability, and efficiency of VT, include various devices. Magnifying glasses may also be utilized for a more detailed look at some visual feature. However, care must be taken to avoid making erroneous decisions regarding the size or extent of some discontinuity when its image is magnified.

Visual inspection methods can be divided into three sub-groups:

Visual examinations prior to welding: drawings, material specifications, edge preparation, dimensions, cleanliness of the welding joint etc.

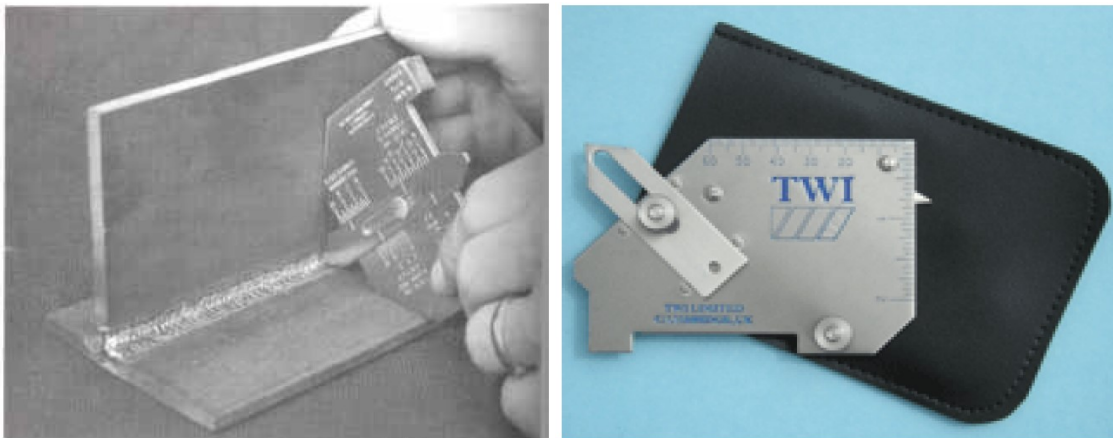
Visual examination during welding: welding process, electrode selection, operating conditions, reheat requirements, welder performance etc.

Visual examinations of the finished weldment: weld size (using weld gauges), defects (surface cracks, creater cracks, surface porosity, incomplete root penetration, undercut, underfill), warpage, base metal defects etc.

In order to preserve the test results, various methods can be employed. These include:

- drawing a sketch, describing the visual appearance using written words
- taking a photograph or video of the surface conditions noted

It is important to accurately record the location, extent, and type of any defect so that the owner, designer, principal and production personnel know what requires repair and where the repair is to be carried out.



Weld inspection gauges

Limitations

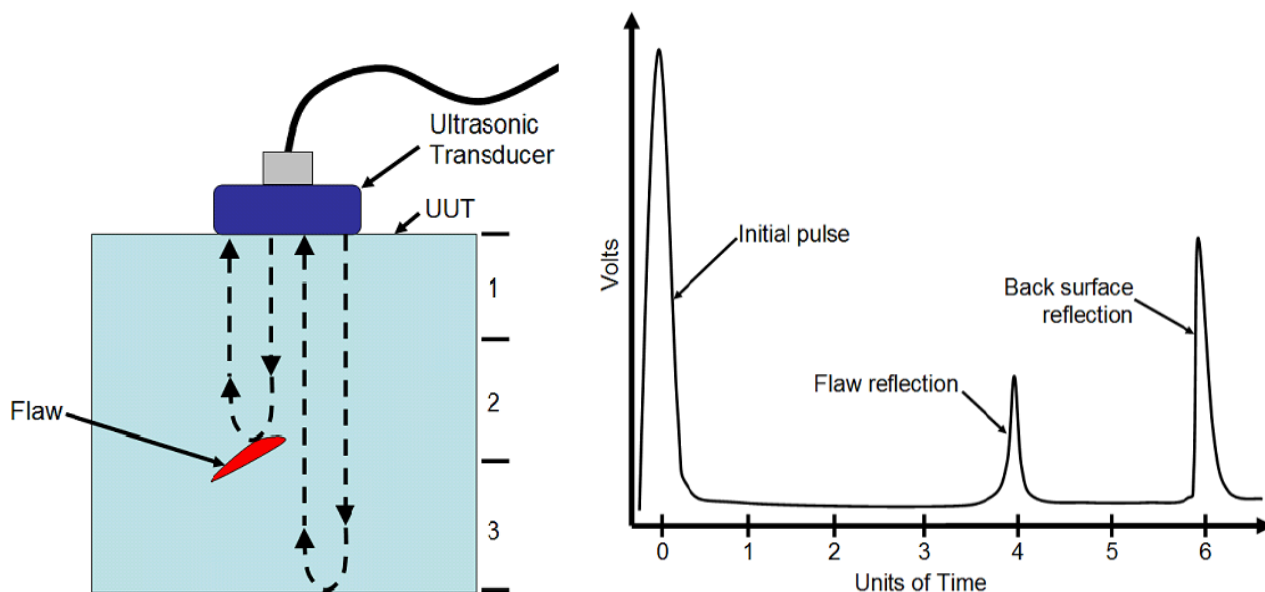
- (a) Restricted to surface inspection
- (b) Good eyesight required
- (c) Good lighting required
- (d) Person performing the inspection must know and be able to recognize what he/she is looking for

Advantages

- (a) Primary method of inspection
- (b) On-going inspection
- (c) Most economical inspection method
- (d) Applicable at any stage of fabrication

Ultrasonic Testing

Ultrasonic testing (UT) is a non-destructive inspection method that uses high frequency sound waves (ultrasound) that are above the range of human hearing to measure geometric and physical properties in materials. There are several ways that sound travels through a material. One type of sound wave, called longitudinal or compression travels at about 330 meters per second in air and about 6400 meters per second in aluminum or in steel at approximately 5960 meters per second.



Ultrasonic Inspection

To perform UT, electrical energy is converted to mechanical energy, in the form of sound waves, by a transducer. The transducer accomplishes this energy conversion due to a phenomenon referred to as the piezoelectric effect. This occurs in several materials, both naturally-occurring and man-made. Quartz is a naturally occurring piezoelectric material. A piezoelectric material will produce a mechanical change in dimension when excited with an electronic pulse. The transducer is excited by a high-frequency voltage that causes a crystal to vibrate mechanically. The crystal probe becomes the source of ultrasonic mechanical vibrations. These vibrations are transmitted into the test piece through a coupling fluid, usually a film of oil, called a couplant.

The sound wave will continue to travel through the material at a given velocity and does not return to the transducer unless it hits a reflector (a boundary between two different materials, or a flaw). If that reflector is favourably oriented, it will reflect the sound back to the transducer at the same velocity. The transducer serves as a receiver for the reflected energy. When struck by this sound wave, the piezoelectric crystal will convert that energy into an electronic pulse which is amplified and displayed as a visual indication on a screen which can then be interpreted by the operator.

By using "calibration" blocks of the correct material having specific dimensions and shapes as well as the various controls on the ultrasonic set, the time it takes for the sound wave to travel through the material can be related to the distance the sound has travelled. Consequently, the ultrasonic set allows the operator to control how long it takes for the sound to travel through the material to a reflector and back to the transducer to facilitate the accurate distance of how far the sound has travelled.

One of the primary benefits of UT is that it is considered to be a truly volumetric test. That is, it is capable of determining not only the length and location of a flaw, but it will also provide the operator with information as to the type of flaw found. Another major advantage of UT is that it only requires access to one side of the material being tested. This is a big advantage in the inspection of pressure equipment, tanks and piping systems.

Another important advantage is that UT will best detect those more critical planar discontinuities such as cracking and incomplete fusion. UT is most sensitive to discontinuities that lie perpendicular to the sound beam.

Because a variety of beam angles can be used UT can detect laminations, incomplete fusion and cracks that are oriented such that detection with radiographic testing would not be possible. UT has deep penetration ability. Modern UT equipment is lightweight and often battery-powered making it very portable.

The major limitations of this method are that it requires a highly skilled operator because interpretation can be difficult. Also, the test object surface must be fairly smooth and couplant is required for contact testing. Further limitations are that reference standards are required and that until recently no permanent record of the CRT display is available. Also it is generally limited to the inspection of butt welds in materials that are thicker than 6 mm.

Limitations

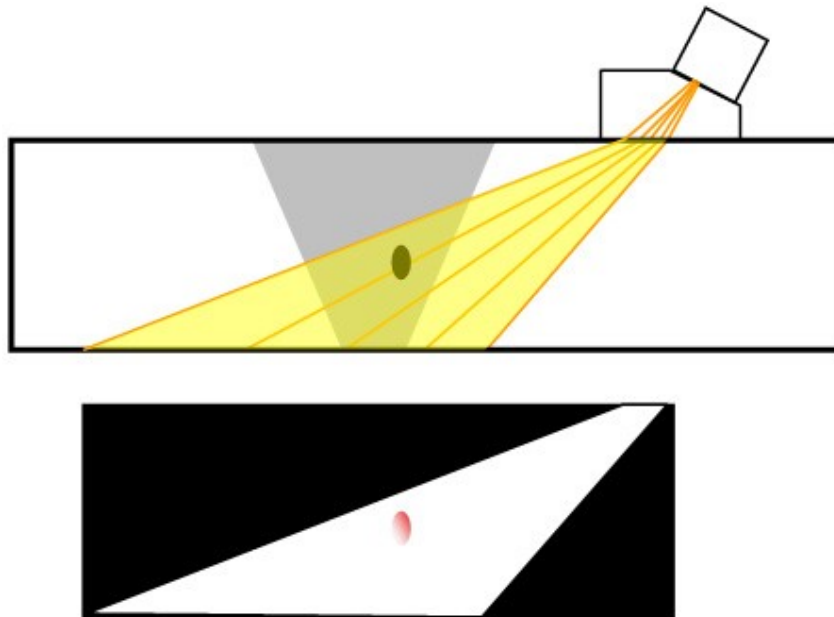
- (a) Test surface must be smooth.
- (b) Couplant required.
- (c) Expensive equipment.
- (d) Reference standards required.
- (e) Results require interpretation by experienced person.
- (f) Inspection of welds over 6 mm thick.

Advantages

- (a) Volumetric inspection.
- (b) Access to only one side required.
- (c) Inspects a variety of thicknesses and weld types.
- (d) Portable equipment.
- (e) Can detect surface and subsurface flaws.
- (f) Can readily size flaws detected.
- (g) Subject to orientation, can detect planar flaws reliability.
- (h) Non-hazardous to personnel.
- (i) Suitable for automation.

Phased Array Ultrasonic Testing

Phased Array (PA) UT is a special technique using a probe which is made up of multiple small elements (transducers), each of which can be pulsed individually at a programmed timing. The term *phased* refers to the timing, and the term *array* refers to the multiple elements. In the figure below the element on the right is pulsed first, and emits a pressure wave that spreads out like a ripple on a pond. The second to right element is pulsed next, and emits a ripple that is slightly smaller than the first because it was started later. The process continues down the line until all the elements have been pulsed. The multiple waves add up to one single wave front travelling at a set angle. In other words, the beam angle can be set just by programming the pulse timings.



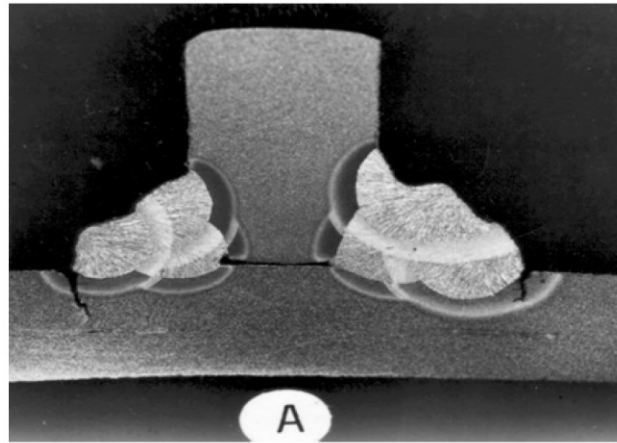
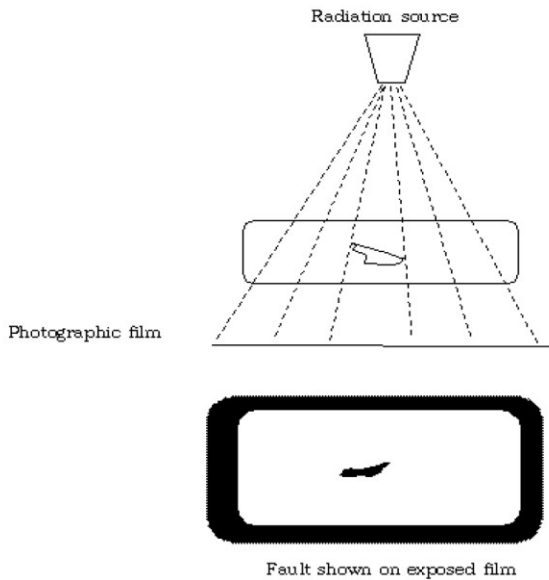
Phased Array UT

By pulsing each of the transducers independently a pattern of constructive interference is set up that results in a beam at a set angle. In other words, the beam can be steered electronically. The beam is swept like a search-light through the object being examined, and the data from multiple beams are put together to make a visual image showing a slice through the object.

Radiography

Radiographic inspection or testing (RT) is a non-destructive inspection method based on using short wavelength electromagnetic radiation passing through the material. Materials with areas of reduced thickness or lower material density allow more, and therefore absorb less, radiation. The radiation, which reaches the film after passing through the material, forms a shadow image on a photographic film (radiograph). Areas of low absorption (slag, porosity) appear as dark areas on the developed film (radiograph). Areas of high absorption (dense inclusions) appear as light areas on the developed film. Lower energy radiation can be in the form of either gamma or X rays. Gamma rays are the result of the decay of radioactive isotope. A common radioactive source is Iridium 192. A gamma source is constantly emitting radiation and must be kept in a shielded storage container when not in use. These containers often employ lead or depleted uranium as shielding.

X rays are produced when electrons, travelling at high speed, collide with matter. The conversion of electrical energy to X radiation is achieved in an evacuated tube. A low current (mA) is passed through a filament to produce electrons. Application of a high potential (kV) voltage between the filament and a target accelerates electrons across this voltage differential. The action of an electron stream striking the target produces X rays; these are produced only while voltage is applied to the X ray tube. Whether using gamma or X ray sources, the test object, e.g. weld, is not radioactive following the inspection.



Radiographic Testing

Subsurface discontinuities that are readily detected by this method are voids, e.g. rounded flaws, metallic and non-metallic inclusions, and favorably aligned incomplete fusion and cracks. Voids, such as porosity, produce dark areas on the film because they represent a significant loss of material density. Metallic inclusions produce light areas if they are denser than the test object.

For example, tungsten inclusions in aluminum welds, which can be produced when using gas tungsten arc welding (GTAW) techniques, appear as light areas on the film. Nonmetallic inclusions, such as slag produce dark areas on the film. Cracks and incomplete fusion must be aligned such that the depth of discontinuities is nearly parallel to the radiation beam for detection.

Radiographic testing can be used to inspect all common engineering materials and is used extensively for the inspection of welds in pressure equipment. Either type of source (X rays or Gamma rays) require film in a light-tight film cassette. Lead letters or lead tape is used to identify the test object. Because of the high density of lead and the local increased thickness, these letters form light areas on the developed film. Penetrameters or image quality indicator "IQIs" are used to verify sensitivity of the radiograph. These are made of known material and known diameters or thicknesses.

Digital radiography is a form of X ray imaging where digital X ray sensors are used instead of traditional photographic film. Instead of X ray film, digital radiography uses a digital image capture device. This gives advantages of immediate image preview and availability; elimination of costly film processing steps; a wider

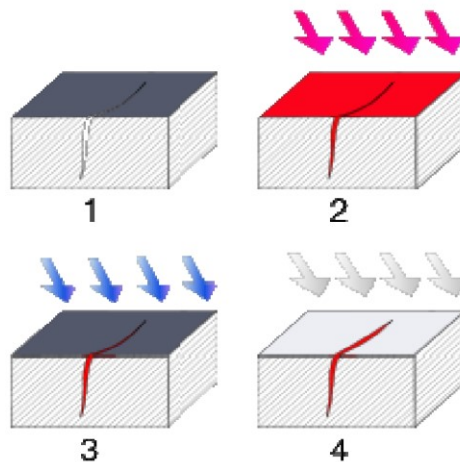
dynamic range, which makes it more forgiving for over- and under-exposure; as well as the ability to apply special image processing techniques that enhance overall display of the image.

Dye Penetrant / Liquid Penetrant

Dye penetrant (DPI) is based upon capillary action, where low surface tension fluid penetrates into clean and dry surface-breaking discontinuities. Penetrant may be applied to the test component by dipping, spraying, or brushing. After adequate penetration time has been allowed, the excess penetrant is removed and a developer is applied. The developer helps to draw penetrant out of the flaw so that an invisible indication becomes visible to the inspector. Inspection is performed under ultraviolet or white light, depending on the type of dye used - fluorescent or nonfluorescent (visible). It is used to detect surface defects in aluminum, magnesium, and stainless steel weldments when the magnetic particle examination method cannot be used.

It is very useful for locating leaks in all types of welds. Welds in pressure and storage vessels and in piping for the petroleum industry are examined for surface cracks and for porosity

For Fluorescent / Penetrant Examination the penetrant is fluorescent and when it is exposed to ultraviolet or black light it shows a glowing fluorescent type of read-out. It provides a greater contrast than the visible dye penetrants. Used for leak detection in magnetic and nonmagnetic weldments. A fluorescent penetrant is applied to one side of the joint and a portable ultraviolet light is then used on the reverse side of the joint to examine the weld for leaks. It is also used to inspect the root pass of highly critical pipe welds.

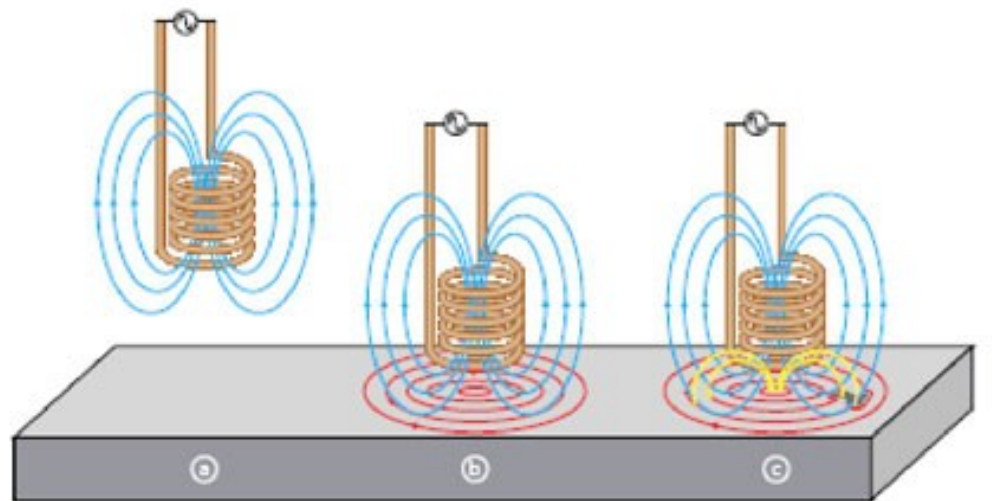


Liquid Penetrant

1. Section of material with a surface-breaking crack that is not visible to the naked eye
2. Penetrant is applied to the surface.
3. Excess penetrant is removed.
4. Developer is applied, rendering the crack visible

Eddy Current Testing

In eddy current testing (ET) a coil carrying an AC current is placed close to the specimen surface, or around the specimen. The current in the coil generates circulating eddy currents in the specimen close to the surface and these in turn affect the current in the coil by mutual induction. Flaws and material variations in the specimen affect the strength of the eddy currents. The presence of flaws, etc. is therefore measured by electrical changes in the exciting coil. Both voltage and phase changes can be measured, but some simpler instruments measure only the voltage changes.



- a—The alternating current flowing through the coil at a chosen frequency generates a magnetic field around the coil.
- b—When the coil is placed close to an electrically conductive material, eddy current is induced in the material.
- c—If a flaw in the conductive material disturbs the eddy current circulation, the magnetic coupling with the probe is changed and a defect signal can be read by measuring the coil impedance variation.

Eddy Current Inspection

The strength of the eddy currents produced depends on the:

- Electrical conductivity of the specimen
- Magnetic permeability (for a ferromagnetic specimen)
- Stand-off distance between the specimen and coil
- AC frequency used in the exciting coil
- Dimensions of the coil and specimen
- Presence of flaws

Much of the success of ET testing depends on separating the effects of these variables. Most eddy current instruments require calibration on a set of test specimens and the flaw sensitivity can be very high. Equipment varies from simple portable meter-read-out instruments, to more complex oscilloscope read-out displaying both phase and voltage; recently the outputs have been digitized to produce fully automated computer programmed equipment with monitored outputs for high speed testing.

Depth of penetration calculations show non ferromagnetic materials have relative and absolute permeability value of 1. The standard depth penetration of the Eddy Current field lines depends on the material electric conductivity and the selected frequency. Therefore, non ferromagnetic materials can be well inspected with the modes and channels as described in the Multiple Frequency Eddy Current Technique.

Ferromagnetic materials, on the other hand, have relative and absolute permeability values far larger than 1. Consequently, the Eddy Current field line depth of penetration is very limited. This is sufficient for surface defect detection such as surface braking crack detection in carbon steel materials.

Applications vary from crack detection to rapid sorting of small components for flaws, size variation, or material variation. Many applications are for bar, tube and wire testing.

Limitations

- (a) Requires highly skilled operator
- (b) Applicable to conductive materials only
- (c) Depth of penetration is limited
- (d) Its application to ferromagnetic materials is difficult

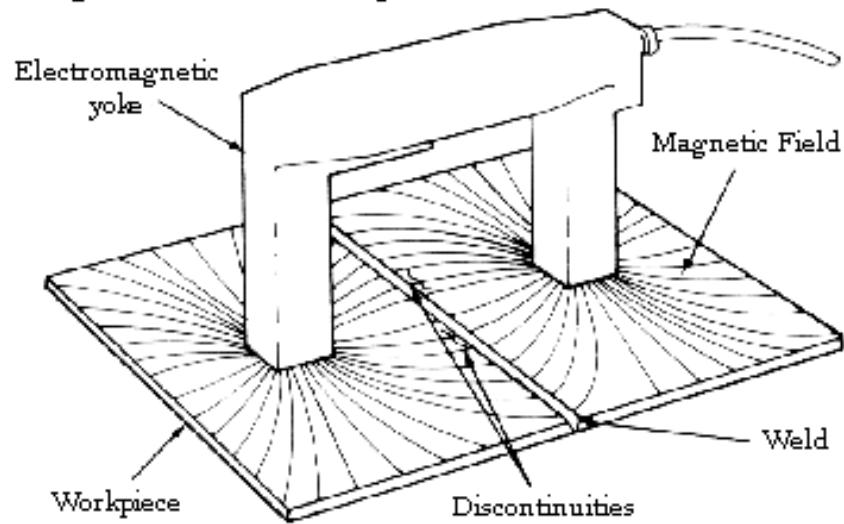
Advantages

- (a) Gives instantaneous response
- (b) Can be easily automated
- (c) Versatile
- (d) No contact between the probe and the test specimen is essential

Magnetic Particle Inspection

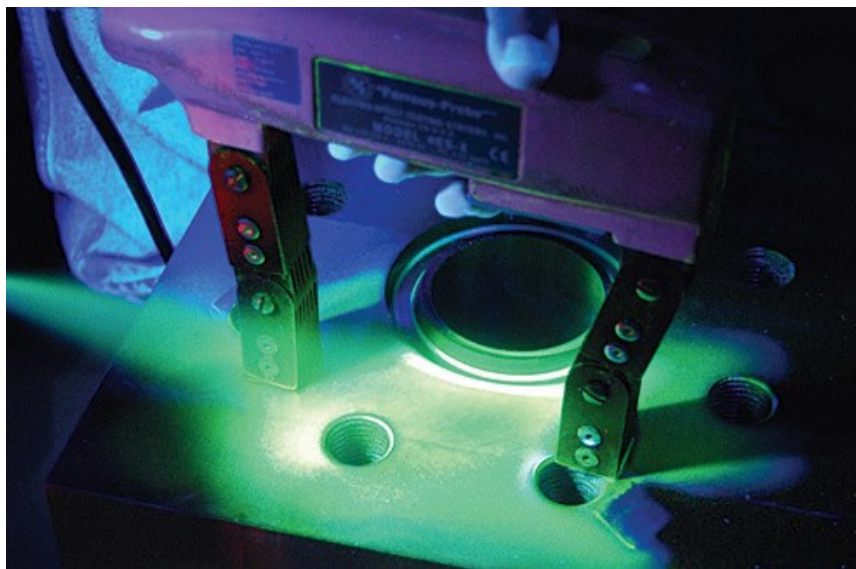
Magnetic particle testing (MT) is used to locate surface and slight subsurface discontinuities or defects in ferromagnetic materials. Any such flaws present in a magnetized part will create a magnetic field, i.e. flux, to leave the part. If magnetic particles are applied to this surface, they will be held in place by the flux leakage to give a visual indication. While several different methods of magnetic particle tests can be used, they all rely on this same general principle. Therefore, any magnetic particle test will be conducted by creating a magnetic field in a part and applying the magnetic particles to the test surface.

Magnetic Particle Inspection



Magnetic Particle Inspection

To understand the principals involved it is worth considering the magnetic lines in a horseshoe magnet. The magnetic lines of force are travelling in continuous loops from one pole to the other. However, if a piece of steel or keeper is placed across the ends (poles) of the magnet, a continuous magnetic path for the lines of force is provided. While there is some flux leakage present at the slight air gaps between the ends of the magnet and the piece of steel, the magnetic field remains relatively strong because of the continuity of the path created by the keeper.



Magnetic particle Inspection

If a discontinuity or flaw is present in the steel bar (keeper) across the ends of the magnet in the vicinity of that flaw, a flux leakage field is created at the flaw surface because the magnetic field leaves the magnetic material and travels through air. If the steel bar is sprinkled with iron particles, such particles would be attracted and held in place by the flux leakage at the flaw. This will occur because the iron particles provide a continuous magnetic path for the lines of force just as the piece of steel across the ends of the magnet completed the magnetic circuit for the magnet.

Therefore, to perform MT, there must be a means of generating a magnetic field in the test specimen. Once the part has been magnetized, iron particles are applied to the surface. When discontinuities are present, these particles will be attracted and held in place to provide a visual indication of the flaw. The use of permanent magnets for MT is generally considered to be inferior to other methods of magnetic particle inspection. Therefore, electromagnets are favored. An electromagnet relies on the principle that there is a magnetic field associated with any electrical conductor.

Either alternating current (AC) or direct current (DC) can be used to induce a magnetic field. The magnetic field created by AC due to the "skin effect" is strongest at the surface of the test object. AC will also provide greater particle mobility on the surface of the part allowing them to move about freely to locate areas of flux leakage, even though the surface of the part may be irregular. Direct current (DC) induces magnetic fields that have greater penetrating power and can be used to detect near surface discontinuities.

Limitations

- (a) Materials or part being inspected must be ferromagnetic
- (b) High currents can be used
- (c) Will only detect surface and slightly subsurface flaws
- (d) Material or part may need to be demagnetized
- (e) Material or part must be clean and relatively smooth
- (f) Equipment can be bulky and heavy
- (g) Power supply generally required
- (h) Coating may mask indications
- (i) Material or part permeability may affect results.

Advantages

- (a) Economical
- (b) Aid to VT
- (c) Can be fixed or portable equipment

- (d) Instant repeatable results
- (e) Effective inspection method
- (f) Contrast or fluorescent consumables.

Magnetic Flux Leakage

In the Oil and Gas Industry Magnetic flux leakage (MFL) is primarily used to detect corrosion, pitting and wall loss in lined and unlined metallic pipelines. The most accurate method of metallic pipeline condition assessment utilizes MFL in-line inspection (ILI) to scan the full circumference and length of the pipeline for corrosion and other mechanical damage. This technology, commonly known as “smart pigging”, has become the industry standard condition assessment vehicle in unlined steel pipelines. Until recently the presence of mortar lining in water pipelines has limited the accuracy and use of ILI inspection and hindered development of practical ILI methods for large diameter, mortar-lined metallic pipelines. However, it is now possible to see through mortar linings up to an inch thick through the use of an “Intelligent Pig.”

With MFL technology, permanent magnets are used to temporarily magnetize the steel pipe and the magnetic field changes are recorded and analyzed. The magnetic flux is uniform if there are no flaws in the wall of the pipe. If internal or external flaws are present, such as pitting, corrosion or other forms of damage, the magnetic flux is distorted beyond the wall of the pipe, and this distortion or ‘leakage’ is measured by Hall Effect sensors.

The advantage of using MFL with intelligent pigs as opposed to Ultrasonics is that Ultrasonics cannot be used to pig gas lines as there is no fluid to act as a couplant to transmit sound waves.



Intelligent Pig

Thermography

Infrared thermography is the process of using a thermal imager to detect infrared radiation (heat) that is emitted by an object. The technology allows operators to validate normal operations and, more importantly, locate thermal anomalies (abnormal patterns of heat invisible to the eye) which indicate possible faults, defects or inefficiencies within a system or machine asset.

A few examples of where infrared is applied in industrial situations include:

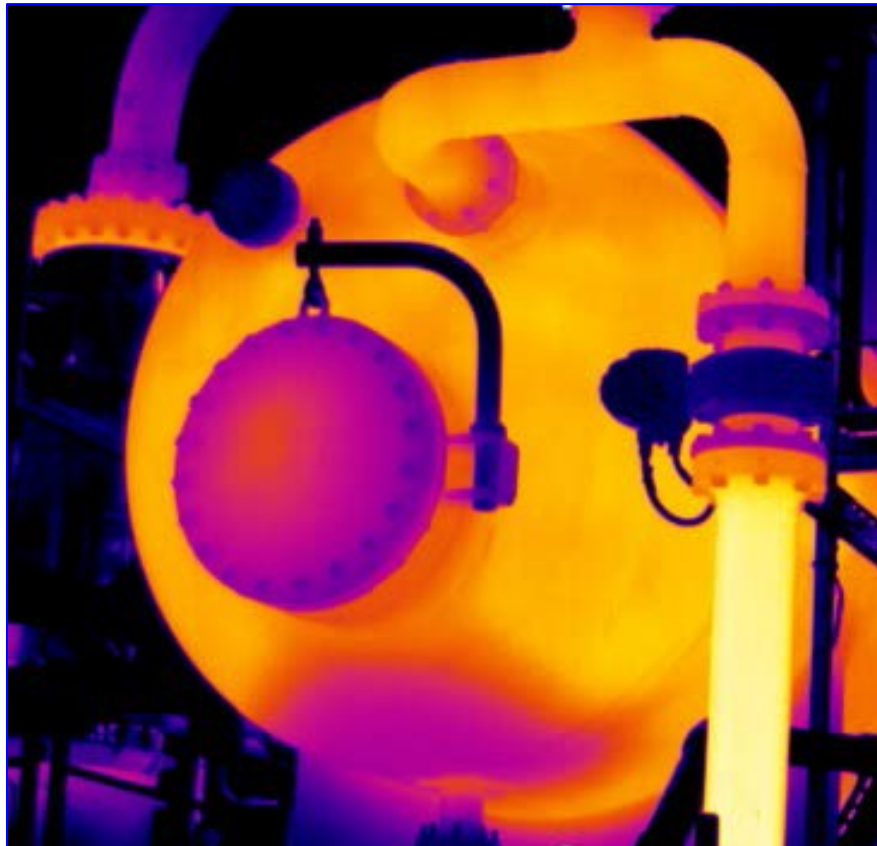
- Electrical Systems (faulty electrical connections or overloaded circuits)

- Mechanical Equipment (abnormally warm motors or possible bearing failures)

- Fluid Systems (line blockages, tank levels or pipe temperatures)

- Building Applications (detect missing insulation, air infiltration or moisture damage)

Inspecting mechanical equipment with infrared thermography covers a wide variety of systems, everything from motors, rotating equipment, steam traps, refractory, and tank levels and more. Most of these inspections de-emphasize taking absolute temperature measurements and instead concentrate on comparing overall thermal patterns to understand the asset's health.



Thermal image showing sand at bottom of vessel (purple = colder area)

Baseline inspections, where a thermograph captures an overall “thermal map” of a particular equipment type, is one of the more valuable uses of the technology, as subsequent inspections are then compared to the original “map” to detail any changes that may have occurred over time.

While there are many ways to monitor the electrical and mechanical conditions of a motor, thermal imaging has proved itself to be useful mainly as a quick and efficient screening tool. Heat is created in a number of ways – by excessive friction, high electrical resistance, reduction of cooling air or fluids and problems with current flow in a motor. If an issue is detected, in the form of an abnormal thermal signature seen in the infrared image – an additional test method such as vibration analysis, ultrasonics or motor circuit analysis – is typically requested to help pinpoint exactly what is causing an anomaly.

Inspecting bearings is another useful application for infrared thermography. Abnormal friction within a bearing, generating heat, causes the bearing’s surface temperature to rise. This thermal signature, when detected, is an indication of a potential bearing problem, anything from under-lubrication, over-lubrication, poor maintenance or simply a bad bearing. Infrared is especially helpful for inspecting low-speed equipment, including overhead conveyors or idlers, quickly and easily.

Both insulation and heat-tracing on process lines can also be inspected with infrared. Applications such as detecting line blockages, monitoring line temperatures, locating damaged or missing insulation can be accomplished with infrared with a few exceptions. Lines covered with very high levels of insulation are more problematic as are process lines that are wrapped with shiny aluminum or stainless steel sheet metal coverings. Inspecting in these situations can be very difficult due to the high thermal reflectivity/low emissivity of the surfaces encountered.

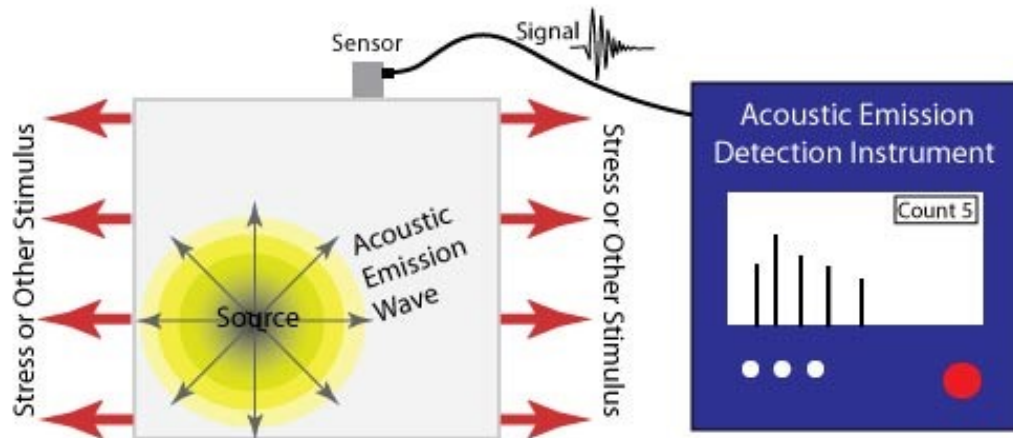
Thermography can be a fast and efficient to locate levels of gases, liquids, fluidized solids and even sludge in tanks, vessels and silos. Although most storage tanks have a gauge to detect levels, these sensors often fail or must be independently confirmed due to the critical nature of a process.

Similar to inspecting line blockages, the different thermal capacities of solids, liquids, and gases and the way heat moves in and out of them mean these materials change temperature at different rates during a transient heat flow cycle. Gases, having the lowest thermal capacity of them all, typically change most quickly. Solids, with varying capacitances do not change as rapidly because slower, conductive, heat flow controls the temperature next to the tank wall. Floating materials, including waxes, can usually be distinguished from the liquid due to capacitance differences. Liquids typically take the longest to change because of their high thermal capacitance.

Acoustic Emission

Acoustic Emission refers to the generation of transient elastic waves during the rapid release of energy from localized sources within a material. The source of these emissions in metals is closely associated with the dislocation movement accompanying plastic deformation and the initiation and extension of cracks in a structure under stress. Other sources of Acoustic Emission are: melting, phase transformation, thermal stresses, cool down cracking and stress build up.

The Acoustic Emission NDT technique is based on the detection and conversion of these high frequency elastic waves to electrical signals. This is accomplished by directly coupling piezoelectric transducers on the surface of the structure under test and loading the structure. Sensors are coupled to the structure by means of a fluid couplant and are secured with tape, adhesive bonds or magnetic hold downs. The output of each piezoelectric sensor (during structure loading) is amplified through a low-noise preamplifier, filtered to remove any extraneous noise and further processed by dedicated electronic equipment.



Acoustic Emission

Acoustic Emission gives an immediate indication of the response and behavior of a material under stress, intimately connected with strength, damage and failure. Acoustic Emission is used also for monitoring chemical reactions including corrosion process, liquid solid transformations, phase transformations. As the method records defects in real time, it offers the possibility of on-line inspection.

When multiple sensors are used, an Acoustic Emission source can be located and, thus, the defective area can be identified. Location is based on the wave propagation principles within the materials and is effectuated by measuring the signal's arrival time to each sensor. By comparing the signal's arrival time at different sensors, the flaw's location can be defined through triangulation.

Limitations

- (a) Requires stress cycling or loading to activate emission sources.
- (b) Acoustic transducers (AE sensors) must contact the surface (directly or via acoustic waveguide).
- (c) Emissions can be ambiguous, subject to interpretation.
- (d) Noise signals (electronic, acoustic, material related) can make flaw emissions difficult to distinguish.
- (e) Requires intensive electronic signal processing and data storage (electronics hardware, computer).

Advantages

- (a) High sensitivity.
- (b) Early and rapid detection of defects, flaws, cracks etc.
- (c) Real time monitoring
- (d) Defective area location: only critical defects provide sustainable Acoustic Emission sources.

- (e) Minimization of plant downtime for inspection, no need for scanning the whole structural surface.
- (f) Minor disturbance of insulation

Corrosion Coupons and Probes

One aspect of Inspection and monitoring which hasn't been discussed is the use of corrosion coupons and probes. A corrosion coupon is a small, specially prepared piece of metal which is placed in a process stream and allowed to corrode for a set period of time.



Typical Weight Loss Coupons and Probes

The most common and basic use of coupons is to determine average corrosion rate over the period of exposure. This is accomplished by weighing the coupon before and after exposure and determining the weight loss. The average corrosion rate can easily be calculated from the weight loss, the initial surface area of the coupon and the time exposed.

It is recommended to leave a coupon exposed for at least 30 days to obtain valid corrosion rate information. There are two main reasons for this. First, a clean coupon generally corrodes much faster than one which has reached equilibrium with its environment. This will cause a higher corrosion rate to be reported in a short test than is actually being experienced on the pipe or vessel. Second, there is an unavoidable potential for error as a result of the coupon cleaning operation. Coupons must first be cleaned following exposure to remove corrosion products and any other deposits. Coupon cleaning procedures are designed to remove all of the deposits without disturbing the remaining uncorroded metal of the coupon. A small amount of the underlying metal is often removed with the deposits, however, and if the actual metal loss from corrosion is small (as would be the case in a short test) the effect of metal removed during cleaning would create a significant error. Care must be taken to correct for this effect. It should be recognized that a coupon can only provide corrosion rate data based on the total weight loss divided by the total time of exposure.

Visual examination of the coupons can also reveal characteristics of the corrosion attack. Pitting rates can be measured, and general corrosion rates calculated from weight-loss data. The coupon material should have corroding characteristics similar to the material in the system.

Besides environment, there are other factors that affect coupon results. They are:

- Coupon material
- Coupon preparation and cleaning procedure
- Coupon location and orientation
- Time of exposure.

Corrosion coupons are often positioned at several locations throughout a system. Corrosion is usually not uniform across a system because of changes in temperature, pressure, flow rates, etc. however, comparing coupon data can give magnitude and location of potential problems.

The orientation of the coupon with respect to flow must also be considered. Coupons should be positioned to contact the electrolyte as uniformly as possible. In cases of stratified flow, the coupon is located on the bottom side of the pipe, or in vertical runs to allow contact with the water phase. Flat coupons are normally oriented so flow impinges on the coupon edge. This will expose the coupon surface more uniformly by minimizing shielding.

Coupon results present a corrosion rate of the coupon itself. Whether this rate is equal to system parts depends on the conditions encountered. In any event, coupon data will provide relative information on changes in a system with respect to time and location. The quality of this relative data is dependent on the consistency of the four factors listed previously.

To compare data from exposure to exposure and location to location, coupons must be from the same supplier. The supplier must use consistent coupon materials, preparation techniques, and cleaning procedures. Coupons do not give immediate data. The analysis can produce a time lag. However, coupons do provide information on the type of corrosion attack. They are easy to use, inexpensive, and applicable to any system.

A major shortcoming of coupon monitoring is that high corrosion rates for short periods of time may be undetectable and cannot be correlated to process upset conditions. If more frequent information on weight loss is desired, Electrical Resistance monitoring systems are used. In many cases, it is recommended that coupons and electrical resistance probes be used in conjunction with each other.

Electrical Resistance probes and instruments are basically "automatic coupons" and share many characteristics with corrosion coupons. Electrical resistance systems work by measuring the electrical resistance of a thin metal probe. As corrosion causes metal to be removed from the probe, its resistance increases. The increase in electrical resistance is proportional to the accumulated corrosion in the exposure period. The probes may be used in all relevant environments, such as oil, water and gas. The major advantage of the electrical resistance method compared to coupons is that measurements can be obtained on a far more frequent basis and require much less effort to make. With automated systems, continuous readings are in fact made and sophisticated data analysis techniques are now available which permit the detection of significant changes in corrosion rate in just a few hours.

As a final comment on Inspection Techniques, it must be remembered that we now have the capability to generate incredible amounts of data with the equipment mentioned above. In the old days everything was recorded manually, now it is digital and the data acquisition rates of the sensors is phenomenal. However, AIM is not just about the data, it is about how we interpret the data and what we do with that information. It is very easy to be blinded and overwhelmed by the technology. Ultimately it is not about building a newer mousetrap, it's about building a better one.

There are a number of software packages on the market which do a good job of looking at inspection data and using it to trend corrosion rates, predict inspection and maintenance frequencies. Coabis, Acet, Integri-Tech, Nexus, Meridium to name a few. All work very well and are used throughout the industry worldwide.

Common NDT Techniques Overview

Examination Technique	Equipment	Defects Detected	Advantages	Disadvantages	Other Considerations
Visual: VT	Pocket magnifier, welding viewer, flashlight, weld gauge, scale	Weld penetration, fitup, cleanliness, roughness, spatter, undercuts, overlaps, weld contour and size, welding procedure	Easy to use, fast, inexpensive, usable at all stages of production	For surface conditions only, dependent on subjective opinion inspector	Most universally used examinations method
Dye Penetrant or Fluorescent: DP, FDP	Fluorescent or visible penetrating liquids and developers; ultraviolet light for the fluorescent type	Defects open to the surface only; good for leak detection	Detects very small, tight, surface imperfections, easy to apply and to interpret; inexpensive; use on magnetic or nonmagnetic materials	Time consuming in the various steps of the process; normally no permanent record	Often used on root pass of highly critical gas welds if material improperly cleaned; some indications may be misleading
Magnetic Particle: MT	Iron particles, wet or dry, or fluorescent; special power source; ultraviolet light for the fluorescent type	Surface and near-surface discontinuities, cracks, etc.; porosity, slag	Indicates discontinuities not visible to the naked eye; useful in checking edges prior to welding, also, repairs; no size restriction	Used on magnetic materials only; surface roughness may distort magnetic field; normally no permanent record	Examination should be from two perpendicular directions to catch discontinuities that may be parallel to one set of magnetic lines of force
Radiography: RT	X-ray or gamma ray; source, film processing equipment, film viewing equipment, penetrameters	Most internal discontinuities and flaws; limited by direction of discontinuity	Provides permanent record; indicates both surface and internal flaws; applicable on all material	Usually not suitable for fillet weld inspection; film exposure and processing critical; slow and expensive	Most popular technique for subsurface inspection; required by some codes and specifications
Ultrasonic: UT	Ultrasonic units and probes; reference and comparison patterns	Can locate all internal flaws located by other methods with the addition of exceptionally small flaws	Extremely sensitive; use restricted only by very complex weldments; can be used on all materials	Demands highly developed interpretation skill	Required by some codes and specifications

Asset Integrity Jigsaw



Asset Integrity Jigsaw

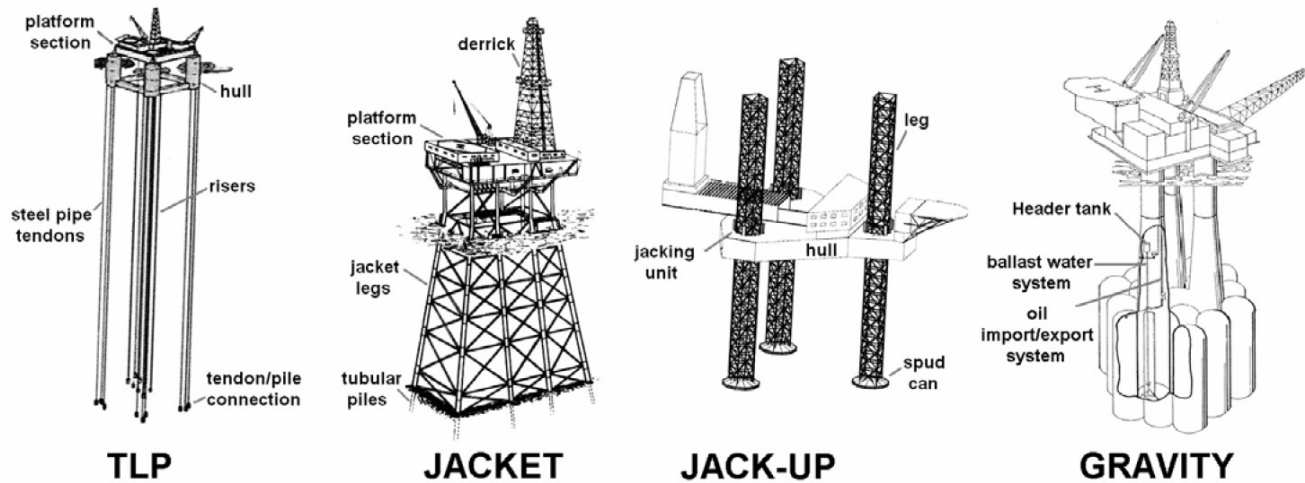
Most Oil Companies will have their own way of displaying their Asset Integrity function. These can be Venn diagrams, Interlinking boxes, flow charts etc. I prefer to keep things simple and devised the Asset Integrity Jigsaw, shown above, and considered the pieces to be: Design, Operate, Inspect and Maintain.

We have all played with jigsaws at some time in our lives and we have all tried to make pieces fit where they aren't meant to go and it is only when the correct pieces are in their proper places that the complete and correct picture can be seen. In many ways Asset Integrity is like a jigsaw and in the real world it is seldom that all the pieces fit together correctly. Each "piece" will be considered separately.

Design

When we talk about Asset Integrity Management it is common to think of existing "brownfield" structures which have been in operation for some time. However, if we are in the situation of a new or "greenfield" project then AIM should realistically start at the design phase.

The design and construction of offshore structures involves a very demanding set of tasks. Over and above the usual conditions and situations met by land-based structures, offshore structures have the added complications of a hostile ocean environment where hydrodynamic loading and dynamic response become major considerations in their design. Additionally, there are a range of possible design solutions, such as: ship-like Floating Production Storage and Offloading Systems (FPSOs), Tension Leg Platforms (TLPs) and Spars along with the more traditional jacket and jack-up oil rigs; and the large concrete gravity-type offshore platforms. They all pose their own peculiar demands in terms of hydrodynamic loading effects, foundation support conditions and character of the dynamic response of not only the structure itself but also of the riser systems for oil extraction adopted by them.



Sample of Offshore Structure Designs

Aside from the structural aspect consideration needs to be given to the use of Corrosion Resistant Alloys (CRA) as a way to try to 'design out' problems associated with internal corrosion in the process vessels and pipework. There is normally a cost implication using these materials but the benefit in terms of reduced inspection and replacement over the asset lifetime will offset these higher costs.

Another important consideration during the design phase is the ability to stand back and look at the design with regard to how it helps or hinders future inspection regimes. The best way to define this is give a practical example. It is not uncommon on older platforms that when an inspection campaign is put in place quite a number of locations for corrosion coupons or Electrical Resistance (ER) probes are found to require scaffolding. This is not apparent when looking at the line drawings; however, onsite reconnaissance shows that the locations are inaccessible without scaffolding. In many cases this situation could have been avoided if this had been considered during the design phase and the locations moved to more accessible areas.

The following is not an exhaustive list but the items in it should be considered during the design phase:

- Subsea Integrity Management Strategy (SIMS)
- Pipeline Integrity Management System (PIMS)
- Major Accident Prevention Document (MAPD)
- Emergency Response Procedures (ERP)
- Inspection, Maintenance and Repair Plans (IMR)
- Planned Maintenance Routines Plan (PMR)
- Hazop studies
- Dropped objects

Operate

The operation of an offshore platform or shore based facility comprises many things and involves diverse aspects from logistics and manning, to process flow and health, safety and environmental considerations. Ultimately good operations are as much about how things are done as about what things are done. One of the best ways to illustrate this is to consider an Offshore Installation Manager (OIM) who in an effort to make his operating costs look better cuts his corrosion inhibitor spending. The problem is that several years later the effects of insufficient inhibitor come home to roost with serious internal corrosion problems which will cost enormous amounts of money to rectify. Think something like this couldn't happen? Think again. It can and does!

In the early 1980's the mantra in the North Sea Oil Industry was: "If you have a problem, throw money at it and it will eventually go away." Then in 1993 came the CRINE (Cost Reduction Initiative for the New Era) reform. CRINE was a UK Continental Shelf response to the pressure of competition in the world of oil and gas. It was an industry wide initiative with the main objective of making it possible to achieve a 30% or more reduction in capital cost for any future oil and gas facilities development. In many ways CRINE was a success. It helped foster the adoption of new standards which ultimately allowed a number of what initially seemed uneconomic fields to be developed but it has also been claimed that it was also the beginning of supply chain management and accountants dictating how the industry was run, and that meant cost cutting everywhere including operations. My father used to say: "some of the worst engineering decisions ever made were made by accountants." He could have been talking about the oil industry!

However, an asset operation needs to be more than just considerations about spending or saving money. It needs to be focused on efficient, sustainable and safe working of the equipment and systems. Many people would argue that it is the most important piece of the puzzle. The following should be considered as fundamental to safe and efficient operations

- Commissioning requirement and report
- Update all the Integrity Documents (Design Phase)
- Risk Based Inspection/Maintenance analysis (RBI)
- Operation procedures
- Life extension studies (If required)
- Remaining life analysis
- Fitness for Service Assessment

Inspect

The most common methods of inspection have already been covered so they will not be discussed again. Suffice to say the Inspect part of the Asset Integrity Jigsaw is all about looking for and finding degradation of the asset over time. The old saying is very true: "if you don't look for it, you will never find it", but this must be tempered with; "it's not just about looking, it is also about where and when to look and what you do when you find something."

Maintain

It is probably not unreasonable to assume that everyone reading this has a car and that car has a dedicated maintenance schedule based around oil changes every 3,000 miles and major services to replace timing belts every 60,000 miles. Most people realize that they don't have to change their oil every 3,000 miles; in fact they could probably run their car for 50,000 miles without any kind of oil change or service. It is also fairly probable that the car would be running like a bucket by the time it got to 50,000 miles and also a fairly high probability that the engine had seen better days!

Equipment manufacturers have prescribed maintenance schedules for a reason. They are designed to ensure maximum longevity and efficiency of their components. It makes sense to follow the recommended service intervals, however, as we have all seen, especially when it comes to offshore installations, what makes sense and what actually happens can be two completely different things.

The primary goal of maintenance is to avoid or mitigate the consequences of failure of equipment. This may be by preventing the failure before it actually occurs which is what Planned Maintenance and Condition Based Maintenance is all about. It is designed to preserve and restore equipment reliability by replacing worn components before they actually fail. Preventive maintenance activities include partial or complete overhauls at specified periods, oil changes, lubrication and so on. In addition, workers can record equipment deterioration so they know to replace or repair worn parts before they cause system failure. The ideal preventive maintenance program would prevent all equipment failure before it occurs



Lack of inspection and maintenance on a flange and bolts

Maintenance Strategies

Maintenance strategies typically fall into 3 main groups. They are not mutually exclusive and the majority of operators employ one or all of them to varying degrees.

1) Corrective Maintenance

Corrective maintenance is maintenance performed after a problem has emerged and is used to identify, isolate and rectify a fault, with the goal of restoring operability. Corrective maintenance cannot be avoided if a system is to remain functioning. Due to limited budgets, many operators have to resort to a corrective maintenance strategy whereby there is little preventative maintenance and the operation just waited until something broke down and then fixed it and carried out maintenance tasks. This process would start by diagnosing why the failure occurred – either through physical inspection or digital assessment (online monitoring etc) – and then repairing or replacing the damaged parts according to the diagnostic findings. Once repairs are made the system is tested to verify that the problem has been solved and validate the continued use of the equipment.

For some older types of equipment it may make sense to rely on corrective maintenance since other types of maintenance are expensive; it may be more cost effective to simply repair components as they wear out, as long as downtime is not detrimental to oil production targets. Downtime, however, can be avoided if regular inspections identify risk of failure in time for maintenance to be planned and scheduled.

2) Preventative Maintenance

Preventative maintenance is maintenance that is carried out to prevent equipment failing or wearing out by providing timely and systematic inspection and detection. The preventative maintenance efforts are aimed at preserving the useful life of equipment and avoiding premature failures which can impact operational requirements such as minimizing downtime and limiting the frequency of corrective maintenance tasks.

The process works through scheduled maintenance programs where the equipment is cleaned, adjusted, lubricated and tested to verify it is in full working order. Inspections are regularly carried out to identify any possible impending problems and planned repairs are scheduled prior to expected equipment failure. Preventative maintenance tends to be carried out only on those items where failure would result in expensive or unacceptable consequences. The preventative maintenance system is recommended when considering extending the life of an asset as it will not only save money but increase uptime in the long run.

3) Predictive Maintenance

Predictive maintenance consists of several techniques that help to determine the condition of equipment in order to predict when maintenance tasks should be performed. This approach helps to save money since tasks are only performed when they are justified. The main value of predictive maintenance is to schedule corrective maintenance that can, at the same time, prevent unexpected equipment failures. The key is to possess the right information which allows correct decisions to be made which avoid unnecessary downtime or routine maintenance tasks. This strategy of planning maintenance helps to increase the equipment lifetime and plant safety, while reducing accidents and environmental impact.

New monitoring and customizable parameter setting technologies allow oil and gas companies to utilize limited time, resources and budgets to greater effect. Predictive maintenance keeps operators from incurring unnecessary costs associated with maintenance, especially when plants or platforms are located in remote areas both onshore and offshore.

When looking at developing optimum preventive and predictive maintenance programs there are a number of building blocks that need to be considered. These include:

- **Knowledge of failure aspects**
 - Failure modes and their characteristics
 - Failure consequences
 - Failure mechanisms
 - Failure causes
 - Age-reliability characteristics
- **Knowledge of predictive tools / techniques**
 - Vibration
 - Thermography
 - Eddy Current
 - Fibre Optics
 - Ultrasonics
 - Radiography
- **Knowledge of methods of analysis**
 - Trending
 - Pattern recognition
 - Data comparison
 - Testing against limits and ranges
 - Statistical analysis

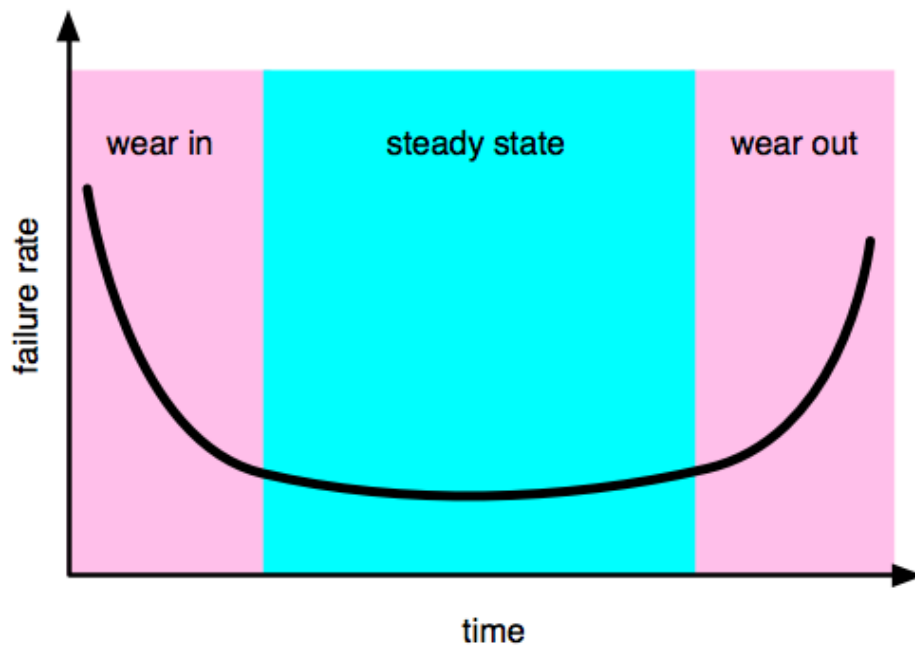
Nowadays there are a number of computer based systems which take over the management of the maintenance function. These are known collectively as a Computerized Maintenance Management System (CMMS) or sometimes a Computerized Maintenance Management Information System (CMMIS).

A CMMS system is effectively a relational database of information about an organization's maintenance operations. (Note: it is common when talking about CMMS to say "CMMS system". Although grammatically incorrect as it doubles up on the word system). The idea behind a CMMS system is to allow integration of all aspects of maintenance from producing work orders to scheduling and tracking of spares. Ultimately this should allow better allocation of time and resources and budgets by helping maintenance teams do their jobs more effectively and allow management to make informed decisions such as calculating the cost of machine breakdown repair versus preventive maintenance. CMMS data may also be used to verify regulatory compliance.

A CMMS system is all about utilizing equipment and asset data and includes maintenance activities, specifications, purchase date, expected lifetime, warranty information, service contracts, service history, spare parts and anything else that might be of help to management or maintenance workers. The CMMS may also generate metrics such as the Facility Condition Index (FCI) to measure effectiveness of the maintenance regime.

Life Extension of Aging Assets

With the relatively recent increase in oil prices and the intention of many operators to extend the working life of a number of platforms, the focus is now on the problems associated with ageing assets. The majority of platforms in the North Sea were designed for an operating life of 25 years. Several of these are now over 50 years old and many more are being considered for a further extension of life by up to 20 years. Many of the problems which such ageing platforms incur can be prevented with systematic inspection and maintenance regimes.

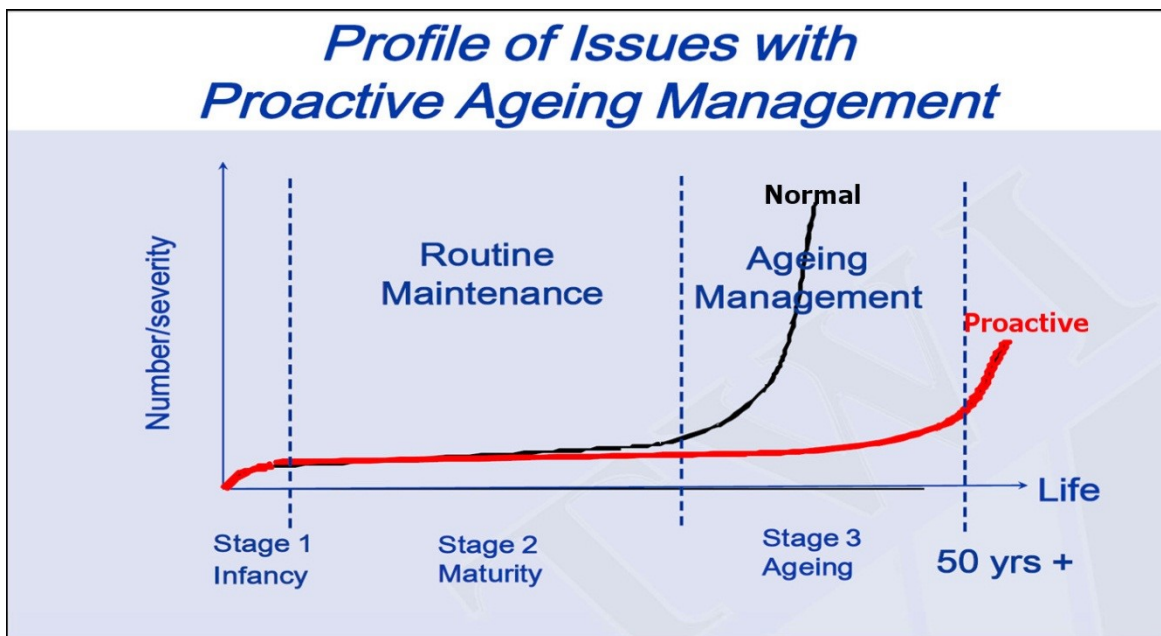


Failure vs Time

One way of considering the life of an oil or gas platform is to compare it to a human body. As every one of us knows, the older we get the more problems we have. Once we have been affected by the early childhood diseases, such as mumps and measles, we normally have a relatively healthy life during our teens, twenties and thirties. Things start to slide in our forties and fifties and, by our sixties; the majority of us have had some kind of health problems. Cancer is normally predominant, with breast cancer being the biggest 'natural' killer of women and prostate cancer being the biggest 'natural' killer of men. Other cancers such as lung and skin cancer are usually self-inflicted and, to a great extent, can be prevented by not smoking or having prolonged exposure to the sun.

In the human body, old age targets certain areas. Arteries, hearts and lungs are of primary concern. Muscles, tendons and skin can largely be ignored (although skin cancer is on the rise). On ageing platforms, it is the hydrocarbon lines that should receive the lion's share of the inspection resources. Produced water and drains may show as much degradation, but the impact of failure on the environment, platform integrity and, more importantly, people's lives, will be much less. Given limited inspection budgets and resources for older assets, the focus has to be not just inspection and maintenance, but targeted, prioritized and smart inspection and maintenance.

Oil platforms follow a similar pattern. After the initial minor commissioning and start-up problems the majority of platforms have a relatively trouble-free life until they are retired from service and decommissioned. However, with many now having exceeded their design life, we are seeing the results of 'old age' and the increasing number of problems that go with extended use. Just like the situation with the human body, many of these problems can be prevented with increased inspection and maintenance regimes. Corrosion is basically the cancer of steel and the old expression 'Rust never sleeps' holds very true. Steel is actually thermodynamically unstable with respect to its oxides and rusting is the primary way for steel to lose the energy that was added in transforming iron ore into a steel ingot. Under normal onshore circumstances, steel which has been given a generous paint coating and is inspected and repainted regularly would be expected to remain in sound structural condition for many tens of years.



Aging profiles

Offshore, things are not so simple. The ocean is one of the harshest environments on the planet. Not only is sea water and salt spray highly corrosive, wave motion and wind will also impart fatigue loading, which combines to give corrosion fatigue. Corrosion fatigue is considered synergistic.

This can be thought of as $2 + 2 = 5$, which means that the combination of corrosion and fatigue acting together is worse than the effects of them both acting separately.

Many human diseases remain undiagnosed and hidden for years and only become noticeable when they start to affect other organs or bodily systems. The same is true for offshore platforms. Take, for example, corrosion under insulation (CUI). CUI is insidious and fairly difficult to detect. An inspection regime requires the removal and reinstatement of the insulation and, in many cases; scaffolding is needed to gain access to the area. For this reason CUI has tended to only become noticeable once the piping has perforated.

Given adequate time, money and resources, inspection regimes can be developed to ensure not only the present integrity of offshore structures and facilities but also guarantee their extended working lives. However, in locations like the North Sea, unknowns such as inclement weather and fog can intervene to sabotage even the best inspection plans.

Another point that is often overlooked also correlates with the medical model, and that is frequency of inspection. In our youth and midlife we tend to have very infrequent visits to the doctor; however, in later years, these increase significantly as our bodies succumb to the ravages of time and, in many cases, neglect. The same is true for offshore installations. The inspection frequency profile for a platform cannot remain static; it has to be a living, dynamic thing that changes as the asset ages. No one would argue that the inspection and maintenance schedules for a three-year-old platform should be the same as for a 30-year-old one – yet, at times, it is easy to forget that simple fact.

Over the lifetime of an asset a wealth of information pertaining to the inspection, maintenance and reliability functions will become available. How that information is used can have a serious effect on the effectiveness and efficiency of the aging strategy. Major influences include using the data to:

- Prioritize inspections
- Extend maintenance intervals
- Engineer out 'bad actors'
- Extend periods between dry dock

One very effective method of prioritizing inspection frequencies is to use the Risk Base Inspection (RBI) protocol. It can be done either qualitatively in case of new builds or quantitatively in the case of an older asset where there is existing inspection data. Using historical data to predict likelihood and consequence of failure becomes more accurate as time goes on and more data is accumulated. Many aging assets will already employ the RBI method to dictate inspection frequencies for both topside and subsea components to generate their 5 year rolling plan. As time goes on an operator should see increased benefits from using RBI as part of its aging strategy.

Being able to extend maintenance schedules can have a dramatic cost impact over the life of the asset. For example if it is possible to extend the service interval of a main generator from 18,000 hours to 26,000 hours, this will take out one service routine over a lifetime and with the elimination of downtime and interruption of production it could realize over \$1,500,000 in savings.

Equally, by using the accumulated data to engineer out the 'bad actors' in the process trains and equipment, resources can be deployed to where they are needed the most. This strategy has already proven effective on such items as sea water lift pumps.

Normally during the life of an asset there are few major changes to the equipment of processes. However, that is not always the case. It is not unheard of for FPSO operations to change the subsea flowlines to a completely different system. For example, current subsea flowlines could be flexible umbilicals, however, these could change to steel pipes for a new gas injection facility. This would entail a revision of the subsea asset integrity system. Greater emphasis would be needed to be given to aspects of coating degradation, cathodic protection and consideration of various operational changes such as internal and external corrosion and erosion modalities which may be encountered during the new lines operational lifetime.

As mentioned before, the inspection and maintenance regime for an asset will not be static but will change during its lifetime. One area of note in any aging strategy concerns decisions that need to be made as the asset approaches time for decommissioning. Normally as an asset ages the frequency and extent of inspections tend to increase. This is a normal consequence of aging. However, as the asset approaches decommissioning there can be conflicting philosophies based on two distinct principles:

- a) The asset will shut down or be sold off soon, why should we spend increasing amounts of money on inspection and maintenance?
- b) The asset is very old and there is a greater probability of failure in a system, we should be doing more inspection and maintenance

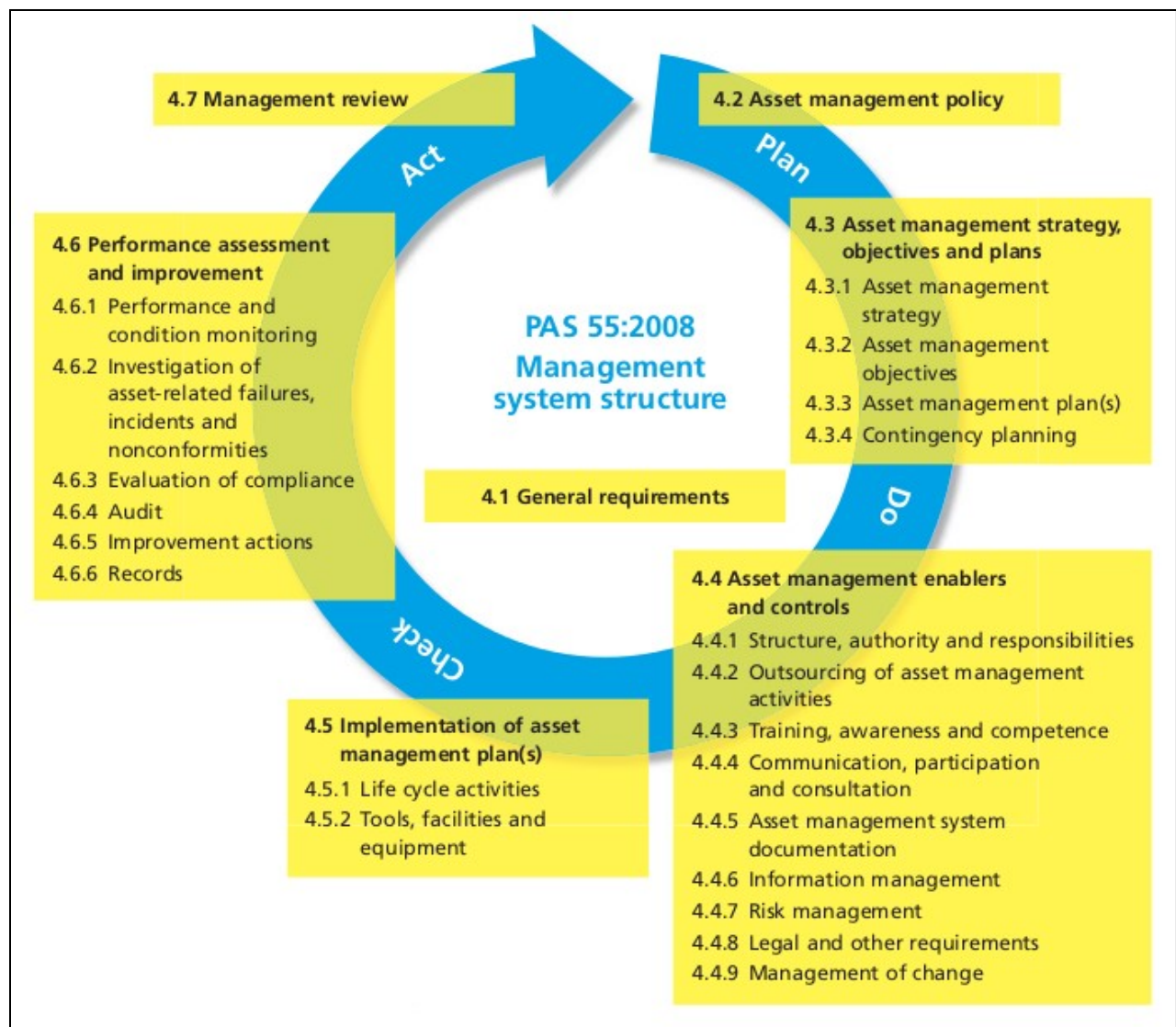
Unfortunately the time for increased spending on inspection and maintenance coincides with a time of dwindling capital returns and it can be these financial factors which drive the asset integrity management at this juncture in the asset's life. Proper management of the aging strategy during the early to middle years can have a deep impact on the investment needed during the last few years of the asset's life.

Not surprisingly, the aging process can be tempered by implementing a proactive integrity management system which incorporates:

- Good data on current and historic condition
- Understanding of degradation processes & responses
- Use of best technology / latest assessment methods
- Development of new techniques (eg. online monitoring)

It needs to be said again: the system has to be dynamic and capable of changing over the life of the asset.

Many industries are implementing ISO 55000 (formerly known as PAS 55) - Specification for the Optimized Management of Physical Assets - as a method to assess their Management Systems and compare them with other leaders in their industry. ISO 55000 defines an Asset Management System as incorporating the following requirements:



Structure of ISO 55000 (PAS 55)

Most Asset Integrity Management systems cover the majority of the ISO 55000 requirements; however, it is felt that with respect to the aging strategy and long term sustainability, it may be worth looking at ISO 55000 and how implementation of its principles could help focus the asset integrity process in terms of long term or extended life.

Ultimately, old assets are like old people. The amount of care and looking after they need depends on how they have been looked after all their lives. The old saying applies to both – ‘Prevention is better than cure’.

Asset Integrity Management System Review

The following topics would be covered when auditing or reviewing a company's Asset Integrity Management system. Not all subjects would be applicable in every case. The following list is not meant to be exhaustive but merely a guide to areas of interest.

COMPANY ASSET INTEGRITY POLICY

- The provision of an Asset Integrity Management System and its financing
- Definition of management responsibility & commitment throughout the company for Asset Integrity
- Ownership and understanding of the system's arrangements with regard to employee communication, consultation and involvement in participation and implementation
- Training and competence at all levels and duties of employees and contractors
- Planning and setting of Asset Integrity objectives
- Resources both human and system to implement the policy
- Demonstration of continuous improvement

PERSONNEL, COMPETENCY & TRAINING

- Definitive job profiles
- Recruitment & selection of appropriately qualified and suitable staff
- Development of criteria that defines the "Person Profile"
- Competence Assessment
- Training and plans for new & existing facilities
- Certification e.g. Survival
- Personal & Career Development
- HSE Awareness and training

OPERATIONS

- Operating Plant & equipment examinations, inspection & test management of the operating envelope.
- PFDs and P&IDS
- Original design flow rates (Oil, Water, Gas)
- Current flow rate (Oil, Water, Gas)
- A copy of Process simulation, Process monitoring & data capture e.g. production reporting
- Operating Procedures for, inter alia, starting & stopping
- Inlet design condition (pressure, temperature at the wellhead and topside)
- Number of processing trains and separation stages for each train on the topsides
- Design parameter for sizing the separators such as retention time and dimensions and operating conditions
- Original Fluid composition
- Current Fluid composition
- Fluid specific gravity original and current
- Chemical injection rates for Emulsion, wax/paraffin, scale inhibitor Anti-foam
- Use of chemicals
- Alarm management including overrides and trips
- Handovers, crew changes
- Isolations standards, valve control, custody arrangements
- Sampling

Standing documentation
Compilation of Operations Integrity Management System (OIMS)
Produced water specification (is produced water re-injected or sent overboard?)
Gas product specification
Natural gas flared or sent to the pipeline for sale or compressed and re-injected
Sand production
Salt produced and if so is crude being desalted?

ASSET INTEGRITY MANAGEMENT

Communication between onshore support staff and offshore inspection and maintenance technicians
Competence assurance of inspection technicians and their supervisors
Documented management system, including Written Schemes of Examination (WSoE)
Identification of Safety Critical Elements (SCE)
Corrosion identification and rectification
Corrosion Under Insulation (CUI)
Deadleg register
Risk assessment / mitigation
Risk Based Inspection (RBI) Process
Recording of inspection work
Deferrals and Backlogs
Measuring the effectiveness of the inspection regime
Inspection and System test of SCE
Condition of plant
Examples of Best Practice
Measuring compliance with performance standards / verification schemes
Measuring the quality of inspection work
Verification
Review of recommendations
Reporting to senior management on integrity status
Key Performance Indicators (KPIs) for inspection effectiveness
Offshore AIM processes
Onshore AIM processes

MAINTENANCE

Competence assurance of maintenance technicians and their supervisors
Interface with Computerized Maintenance Management Systems (CMMS) including register of assets
Maintenance plans and schedules for equipment and execution
Maintenance of safety critical elements
Measuring the quality of maintenance work
KPIs for maintenance effectiveness
Critical and non-critical spares management
Supervision
Recording of completed maintenance work
Deferrals and Backlogs
Corrective Maintenance
Defined Life Repairs
Measuring the effectiveness of the maintenance system
Life Saving Appliances
Pipework of all diameters – including small bore and pipelines
Heat exchangers

- Pressure vessels and their relief devices
- Electrical
- Lifting & loading equipment
- Rotating equipment – pumps, compressors, fans
- Process control and Emergency Shutdown Devices (ESD)
- Instruments – including fire & gas
- Tanks
- Fire Protection – active and passive
- Structures
- Navigation aids & Communications equipment
- Fired boilers
- Temporary Equipment

MANAGEMENT OF CHANGE (MOC)

- Engineering changes, including maintenance, inspection & testing
- Process changes – including changes in flow stream components
- Changes to procedures
- Changes to software (but not to standard office based IT systems)
- Organizational changes
- Formal documentation of these processes

INTERFACE MANAGEMENT

- Contracts & Procurement – the process, authority levels and execution
- The provision of 3rd party services, their control, utilization and deliverables
- Facilities interfaces where they are an integral part of the Operation e.g. pipelines
- Appointment of Company Designated Site Representatives for every contract
- Shutdown Development, Management & Coordination
- Transfer of knowledge from one phase of a project to another
- Transfer of ownership of assets inter & intra company

WELL ENGINEERING

- Compliance with relevant legislative environment
- Full Well Life Cycle involvement
- Clear, accountable leadership
- Clearly defined roles and responsibilities
- Documented Management system, including Written Schemes of Examination (WSoE)
- Interface with related Asset Integrity Management systems eg Pressure Systems
- Identification of Safety Critical Elements (SCEs)
- Performance Standards
- KPIs - technical and business
- Risk assessment / mitigation
- Maintenance plans and schedules for equipment and execution
- Appropriate SCE / barrier test and inspection frequencies
- Control systems equipment testing
- Defects identification, repair and reporting
- Corrosion identification and rectification
- Annulus pressure monitoring and reporting
- Annulus liquid level top up

Knowing the difference between annulus Maximum Allowable Annulus Surface Pressure (MAASP) and Maximum Allowable Surface Pressure (MASP)
Well control during well intervention operations
Well Handover through life cycle phases
Well Handover between well intervention and production operations
Management of abnormal conditions e.g. High Pressure High Temperature / H2S
Integrated web based management tool suite
Real time integrated data collection that is globally available
Trend recognition / analysis
Record keeping and results appropriately documented
Well equipment status files
Well anomaly reporting, review and remedial actions
Understanding of the Well Examination / Verification Interface
Continued education and engagement of staff in Well Integrity delivery

PIPELINES

Pipeline System means:

Pipework (including associated risers), valves, pressure vessels e.g. pig traps, control & measurement systems, cathodic protection, support structures, inspection provision, connections and injection points included in the pressure containing envelope peculiar to a pipeline system as distinct from similar equipment found on offshore and onshore installations: a system for the conveyance of the designated pipeline contents.

Pipeline safety

Pipeline design and construction

Risk Based Inspection (RBI)

Pipeline operating codes and standards

Emergency shutdown valves requirements

Inspection, testing, maintenance and cleaning of pipelines

Pressure systems safety

Corrosion management of subsea pipelines

Change management

Anomaly management

Verification procedures

Health Safety and Environment (HSE)

No book on Asset Integrity Management would be complete without some reference to HSE. Although it should be implicit in everything we do nowadays, the number of accidents that occur which result in injury and loss of life shows that there is still room for improvement in both functionality and awareness.

Although there are many aspects of HSE and to do justice to all of them would take a book in itself, it is worth spotlighting the Job Safety Analysis (JSA) protocol.

A Job Safety Analysis is a method that can be used to identify, analyze and record:

- 1) The steps involved in performing a specific job
- 2) The existing or potential safety and health hazards associated with each step

3) The recommended action(s)/procedure(s) that will eliminate or reduce these hazards and the risk of a workplace injury or illness.

Hazard Types:

The following hazards should be considered when completing a JSA:

Impact with a falling or flying object.

Penetration of sharp objects.

Caught in or between a stationary/moving object.

Falls from an elevated work platform, ladders or stairs.

Excessive lifting, twisting, pushing, pulling, reaching, or bending.

Exposure to vibrating power tools, excessive noise, cold or heat, or harmful levels of gases, radiation, vapors, liquids, fumes, or dusts.

Repetitive motion.

Electrical hazards.

Light (optical) radiation (i.e. welding operations, etc.).

Water (potential for drowning or fungal infections caused by wetness).

Conducting the analysis:

1. Select jobs with the highest risk for a workplace injury or illness.
2. Select an experienced employee who is willing to be observed. Involve the employee and his/her immediate supervisor in the process.
3. Identify and record each step necessary to accomplish the task. Use an action verb (i.e. pick up, turn on) to describe each step.
4. Identify all actual or potential safety and health hazards associated with each task.
5. Determine and record the recommended action(s) or procedure(s) for performing each step that will eliminate or reduce the hazard (i.e. engineering changes, job rotation, PPE, etc.).

The following is an example of a JSA form

JOB SAFETY ANALYSIS

WORKING AT HEIGHTS

ACTIVITY:	Working at height / Rope Access NDT	ORIGINAL DATE:	
DEPARTMENT INVOLVED:		REVISED DATE:	
TITLE OF PERSON DOING JOB:		LOCATION OF ACTIVITY:	
PERSON SUBMITTING JSA:		SUPERVISOR	
UNIT SUBMITTING JSA:		SUPERINTENDANT	

SAFETY EQUIPMENT AND DOCUMENTATION REQUIRED TO DO THIS JOB:

☐ Hearing Protection	☐ Tag Lines	☐ Danger/Caution Tape	☐ MSDS
☐ Hard Hat	☐ Work Vest	☐ Cable Strippers, Tether	☐ Work Permit Required
☐ Safety Shoes	☐ Face Shield	☐ Lock out /Tag out	☐ Cold Work Permit
☐ Safety Glasses w/ Side Shields	☐ Insulated Ladder	☐ Back Belts	☐ Spark Potential Permit
☐ Cotton Gloves	☐ Dust Mask	☐ Barricades	☐ Confined Space Permit
☐ Leather Gloves	☐ Fall Arrestor with in date certification	☐ Goggles	☐ Crane Lifting Plan
☐ Rubber Gloves	☐ Slings with in date certification	☐ Fire Watch	☐ Working Aloft Permit
☐ Safety Harness	☐ Harness Lifting Web, Telemetry Can	☐ Fire Extinguisher	☐ 2- Life Rings w/ 90' Floating Line?
☐ Slip and/or Trip Hazard	☐ Trapped Energy	☐ Electrical Hazards	☐ Mechanical Hazards

Please Remember: All hazards are important. Make notice of all possible hazards. Detailed safe job procedures are necessary. Awareness, teamwork, communications, and alertness apply to every situation. Use complete recommendations to eliminate or reduce hazards.

AUTHORIZATIONS REQUIRED TO DO THIS JOB:

☐ Operations Management	☐ Ballast Control	☐ Dive Superintendent	☐ Vessel Capt./1 st . Mate
☐ ROV Superintendent	☐ Barge Engineer.	☐ Manufacturing Manager	☐ Company Representative
☐ ROV Supervisor	☐ Dock Forman	☐ Manufacturing Leads	☐ 3 rd Party Representative
☐ OIM/Senior Tool Pusher	☐ Chief Engineer	☐ Tooling Manager	☐ Barge Superintendent
☐ Client	☐ Electrician	☐ SCR Room	☐ Deck Forman
☐ Project Manager	☐ Vessel Supt	☐	☐

COMMENTS:

BASIC JOB STEPS	POTENTIAL HAZARDS	RECOMMENDED SAFE PROCEDURES
Preparation for task	Unsafe work area, hazards of concurrent tasks, unsafe weather conditions, inadequately trained and certified personnel.	• Obtain appropriate work permits • Inspect work area and carry out housekeeping and controls of potential hazards • Put up barriers and warnings, announcements as required. • Ensure all persons carrying out the task are trained and certified in working at height / rope access as applicable. • Monitor weather. Do not carry out task if weather conditions are unsuitable, particularly with regard to heavy winds and rain. • Tool Box Talk to be carried out, rescue plan to be in place prior to carrying out task, and discussed with all members.
Preparation and Rigging of equipment	Falls from height, slips & trips, interference from surrounding structures, unsafe and inadequate tools and equipment	• Inspect all tools and equipment, ensure adequate numbers available. • If using ladders and climbing equipment, ensure all such equipment is in good working condition. • If working off scaffold, make sure all scaffolding has been safely installed, scaffold tags are in place and in date. • If using Rope Access, IRATA Level III to be in attendance at all times. • Work to company procedures • All harnesses and safety gear to be inspected prior to every use. • All ropes and lanyards to be protected / deviated from hot pipes, sharp edges and any structure that has potential to damage the same. • All workers to be kitted with PPE appropriate to the task being carried out. PPE to be well fitting, hard hats to be kitted with chin straps as required.
Carrying out tasks – Inspections / NDT of pipes and structures.	Falls from height, dropped objects, hazards of concurrent tasks, unsuitable weather conditions, hazards from the nature of NDT task being carried out, exhaustion.	• Inspect all tools and equipment and all safety gear prior to every use. • Area under ongoing task to be zoned off, warnings and look out in place. • All tools and equipment to be tied off. • If using Rope Access, IRATA Level III to be in attendance at all times. • Work to company procedures • All persons to be aware of surrounding structure they may take support from. • Monitor weather. Do not carry out task if weather conditions are unsuitable, particularly with regard to heavy winds and rains. Regular breaks to be taken, particularly in hot / humid conditions. • Controls to also be in place specific to the nature of the NDT task being carried out.

No job is ever so urgent or important that we can't take the time out to do it safely or environmentally correct.

[illegible]

Review Checklist	Yes	No	Initial
SLIP HAZARD	☐	☐	
TRIP HAZARD	☐	☐	
LOCK-OUT/TAG-OUT	☐	☐	
FALL PROTECTION	☐	☐	
CONFINED SPACES	☐	☐	
CRANE SAFETY	☐	☐	
TRAPPED ENERGY	☐	☐	
BARRICADES	☐	☐	
ELECTRICAL HAZARDS	☐	☐	
MECHANICAL HAZARDS	☐	☐	

Asset Management Triangle

As many people have probably realized by now Asset Integrity Management involves a large number of concepts, theories, practices and variables. I've tried to cover what I consider the most important aspects and hopefully that will set people on the path to learn more and put what they learn into practice. When I had finished what I considered to be a complete book I felt that there was still something missing, something which summed everything up in a simple and concise manner. I eventually came up with the Asset Management Triangle.



Asset Management Triangle

The colors are purely arbitrary and could be changed if the Triangle was used to assess a system. For example Green could indicate complete compliance. Yellow could indicate partial completeness, Blue could mean major gaps and Red could indicate complete failure etc. As the system was improved and reassessed the colors would change to indicate progress.

The Asset Management Triangle can be used for both existing "Brownfield" assets and new "Greenfield" assets.

Putting it into Practice

Hopefully everything that has been presented up to now will have given the reader an insight into what is involved in Asset Integrity Management, from the problems encountered to the tools available to manage those problems. This last bit is a very generic, high level “Putting it into Practice” guideline. It has been written from the standpoint of what would you do if suddenly you had to take over an Asset Integrity Management function for an Oil and Gas Operator. We'll call them XYZ Oil and Gas. It doesn't cover everything but it should get you thinking and moving in the right direction.

For this high level overview of XYZ Oil and Gas's Asset Integrity Management system several assumptions have been made. The first is that all inspection is subcontracted out to a 3rd Party and that XYZ Oil and Gas does not have its own team of Inspectors or Inspection Engineers. The other assumption is that record keeping is robust and all historical inspection and analysis data is available.

Before embarking on any course of action, the present status needs to be determined. That involves asking questions of the heads of inspection / maintenance departments, inspection contractors and Offshore Installation Managers (OIM)s. The most fundamental ones are:

What are the biggest worries / fears you have with regard to the Asset Integrity of XYZ Oil and Gas's offshore, and onshore facilities?

What is your top 10 bad stuff list and what keeps you awake at night?

Do you have enough resources and budget to do the work that you feel necessary?

The rationale behind this approach is that for many companies like XYZ Oil and Gas, their Assets are for the most part mature. In many cases, over time, those companies lose sight of what the objectives of Asset Integrity are. They focus on doing the same thing year in and year out because “that's what we have always done.” Few have a top 10 bad stuff list because there is a lack of prioritization. With a top 10 list there is a focus on dealing with the number 1 problem, removing it so number 2 now becomes number 1 and number 11 then becomes number 10 etc. In many cases politics have come into play. “No outstanding overdues by the end of the year”, for example. This is easily mandated by senior management but it is often done with no real understanding of why there will be outstanding overdues and the pressure it puts on the integrity / inspection team to clear them. Sometimes it needs for either an outside observer to come in or for people to step back and “smell the coffee” and look and take stock at what they are doing.

It is recommended that the Assets are visited to assess the condition of the facilities and the inspection / maintenance programs.

One of the questions to ask of the integrity / inspection team is; “if we weren't doing this job and someone else came in, would they do what we are doing?” Interestingly enough, it is not uncommon for the answer to be “No!” The response has to be; “OK, then, why are we doing it?”

There are a number of areas which need to be reviewed and analyzed when assessing an existing asset integrity system. Not all of the following 24 areas will be relevant in every situation but they make a good starting point.

Operator Competency	Work Activity Control
Operating Procedures / HSE	Planning and Scheduling
Equipment Ownership	Spares and Support Equipment
Maintenance Plan Development	Maintenance Procedures
Plant Condition and Performance Monitoring	Fixed Equipment Integrity Plan Development
Lubrication Management	Maintenance / Equipment History
Defect Elimination	Materials Management
Corrosion Monitoring and Control	Service Management
Quality Assurance and Control	Document Management
Maintenance Competency	Loss Reporting
Management of Change	Processes and Metrics
Reliability Program Management	Risk Based Inspection Protocols

Next up would be a complete review of historical data and trend analysis and assessing whether that information is being acted on to rationalize the inspection and maintenance programs. Again prioritization of the threats to the Assets would be top of the list.

With unlimited, time, money and resources, you can have an almost perfect Inspection and Integrity System but that isn't the world we live in so there is the need to find out what XYZ Oil and Gas has and how effective those systems are. Regarding external contractors, is XYZ Oil and Gas actually getting what it needs from its contractors? Presumably for offshore they are rotators with recognizable NDT qualifications. However, qualifications are not always everything. There have been cases where qualified UT Technicians who had never worked on offshore piping had no experience of the type of defects that are commonplace and failed the Operator's own internal verification tests.

Looking at what XYZ Oil and Gas is doing, the question has to be asked: Are there other more efficient ways of doing things? Increased use of new technology or new inspection philosophies such as DNV RP G103 - Non Invasive Inspection, for example?

A major consideration would be to perform a Risk Based Inspection assessment on the systems in operation. Is there already an RBI system in place? If so, the questions would be; "what happened regarding the outcomes and how did they affect the inspection frequencies / regimes for the Assets and is it now time to revisit that RBI because it was done (for example) 5 years ago?"

One of the problems with aging assets is that the operating conditions may have changed over the last 10, 15, 20 years. What was originally designed for sweet service is now seeing sour, H₂S crude. That will now bring a whole new set of problems and degradation modes (Hydrogen embrittlement, Hydrogen cracking etc.) which need a whole new prevention / inhibition regime. Same goes for increased sand in the lines and vessels which changes the failure mode to more erosion rather than corrosion. This means that the inspection frequency also needs to change.

Next to look at would be the Performance Standards and Verification Schemes that are in place. When were they devised? Do they correctly identify the risks and operations that are currently in place at XYZ Oil and Gas? Also it is worth remembering that what works well for an onshore operation may not for offshore. The logistics, expense, timing etc. are different. A storm or stretch of bad weather can decimate a planned inspection and maintenance program offshore. What happens if a campaign gets delayed or cancelled? What about temporary repairs? As we all know, temporary repairs tend to become semi-permanent. How are these justified?

The problem with an Asset Integrity system is that it cannot be static. It has to be a “living, breathing” thing that changes over time. It is important that it changes to reflect the age and operational characteristics of the facilities. The inspection regime for a 3 year old platform is different to one that is 30 years old. There are different economics in play and different drivers. That’s why it is imperative to periodically stand back and take the “helicopter view”. Unfortunately many operators just blindly follow the scheduling that is generated by inspection programs without analysis of what is actually needed. Part of the initial review of the Integrity Management system would be to look at what is actually driving the inspection protocols and frequencies and prioritization.

Effective inspection regimes involve; identification, prioritization and systemization.

Identification involves ascertaining where the problem areas are and what failure mechanisms are involved. Internal corrosion / erosion, external corrosion, CUI, corrosion fatigue, stress corrosion cracking and hydrogen induced cracking are a few of the major failure mechanisms.

Prioritization involves a process of ranking the different consequences of failure unveiled in the identification step and incorporating a measure of probability of them occurring. There are a number of different ways in which to rank and prioritize. These include loss of life, loss of revenue and environmental impact.

Systemization involves both being systematic and covering all the relevant systems. This will necessitate effective allocation of time and resources which may be a bigger obstacle than it seems. A great example is trying to organize offshore inspections in a geographical region which is subject to excessive bad weather i.e. fog or rain. Helicopters get cancelled and vessel movements are disrupted which invariably leads to the inspection timetable being compromised.

Next would be budgeting and resources. XYZ Oil and Gas may want the best Integrity Management system possible, but what exactly does it need? It needs an operation which is safe, environmentally friendly, and efficient, meets Government / HSE regulations and is profitable. That costs money. Is there the budget to achieve the goals? Are there sufficient resources? Are there enough support engineers available for analysis and interpretation of inspection findings? How many corrosion engineers, integrity engineers do they have? Are the engineers overstretched and under pressure and more prone to mistakes and shortcutting? Is there undue pressure on them to reduce overdues and hence sign off on things that really need to be addressed?

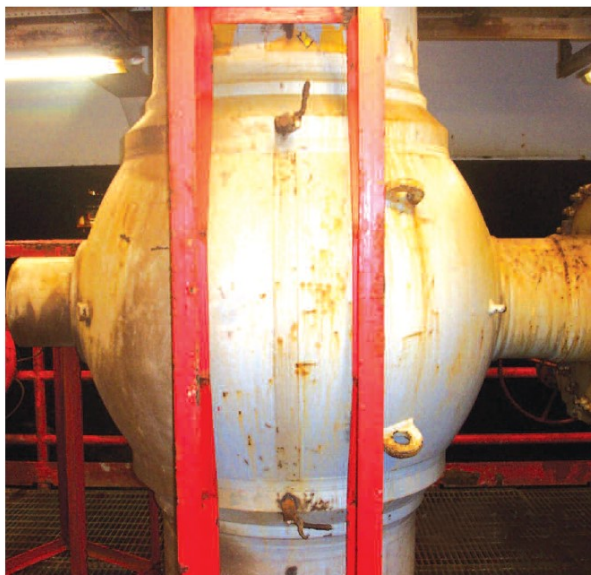
This last point is very important. Many a system falls over because of the people operating it. Have they the right qualifications and experience? Do they knit well as a team or are they all individuals. Is there synergy as a group or do they work in silos, interested only in their own little piece of the puzzle? What about retention and training or personnel? The best AIM system in the world will fall apart if the right people are not operating it. Does XYZ Oil and Gas look at training as an investment or an expense? The answer will tell a lot about the company.

All this ties into XYZ Oil and Gas’s Corporate Reliability Performance Standards. When were these devised and have they been revised as the company has grown? Many times these high level documents are more of a wish list rather than a must have list and are open to interpretation further down the chain. Also even though they originally encompassed the company’s operations, if there were acquisitions and a change in direction and focus they may need modification.

Obviously there is a lot more involved in the whole process but this should give anyone a good start when they come to review or implement an Asset Integrity Management system.

Appendix

Excerpt from UK HSE Offshore External Corrosion Guide



Pipe supports and pipe coatings

Where to look	What to look for
General target areas	■ Piping ■ Pipe supports ■ Spring supports ■ Fretting surfaces
What to look/ask for	■ Paint condition? ■ Thick corrosion deposits? ■ What are the paint and fabric maintenance programmes? ■ What action is taken to ensure areas around pipe supports are painted?
Corrosion management	■ What external corrosion problems have there been?

Threaded plugs

Where to look	What to look for
General target areas	■ Valve bodies ■ Xmas trees ■ Piping – usually low and high locations on pipe work
What to look/ask for	■ Are pipe plugs rare or numerous? ■ Are there dissimilar metal issues? ■ Condition of threads? ■ Leaking pipe plugs? ■ Rust stains?
Corrosion management	■ Replacement by non-threaded equipment ■ No dissimilar metals ■ Replacement and thread inspection programme ■ What failures have there been?



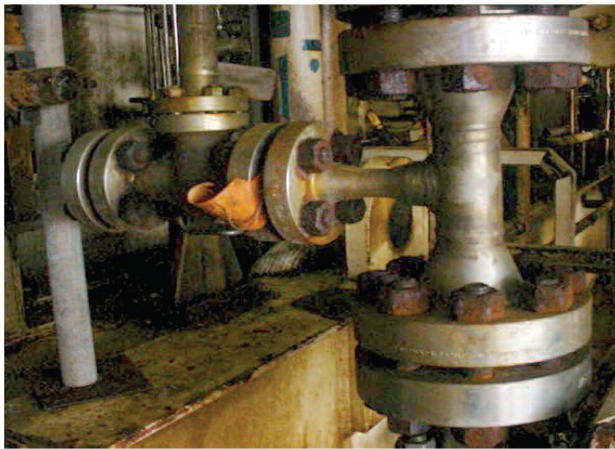
Corrosion under insulation

Where to look	What to look for
General target areas	- Water traps, eg low points, brackets, penetrations, support rings - Areas of personnel traffic - Insulation terminations
Cladding condition	- Rusty surface/corrosion holes? - Joint sealant condition? - External condensation/icing?
Penetrations (eg branches, supports, structural members)	- Sealed/sealant in good condition? - Signs of water ingress/wet insulation? - Salt encrustations around penetrations?
Joints	- Are the joints generally in good condition? - Insulation visible through joints? - Deformed/poor fit?
Damaged insulation	- Deformed? - Signs of being walked on? - Impact damage?
Corrosion management	- CUI inspection programme? - Personnel protection replaced by cages? - CUI problems/failures?



Firewater mains and deluge systems

Where to look	What to look for
General target areas	- Mixed metals, non-metallic? - Spray and monitor nozzles - Temporary repairs - Valves - Flanges
Spray and monitor nozzles	- Blocked? - Salt encrustations? - Corrosion products?
Temporary repairs	- Number? - Leaking? - Repair type?
Flanges	- Leaks? - Dissimilar metals?
Valves	- Leaks? - Dissimilar metals?
Non-metallic piping	- Leaks? - Joint condition? - Local colour changes?
Corrosion management	- Is it a wet or dry system? - What is the inspection programme? - How often is the deluge system tested? - What is the corrosion management programme? - What is the failure history?



Bolts and nuts

Where to look	What to look for
General target areas	- Mixed metals - Valves - Flanges - Pumps - Xmas trees - Corroded bolts/threads - Fractured bolts - Nuts grossly enlarged by corrosion product
Corrosion protection	- Unprotected - Grease 'Denso tape' - Galvanised - Nickel-plated - Corrosion-resistant alloy
Corrosion management	- What is the inspection programme? - What is the failure history?



Valves

Where to look	What to look for
General target areas	- ESDVs - Xmas trees - Choke valves - Pressure relief valves - Drain valves - Block valves
What to look/ask for	- Corroded handles/wheels? - Corroded valve stems? - Leaking stems? - Leaking flanges? - Leaking valve bleed plugs? - Are valves properly supported? - Paint condition? - Corrosion-resistant materials?
Corrosion management	- What is the valve test programme? - What is the inspection programme? - What is the failure history?

Definitions

- ALARP - As Low As Reasonably Practicable. For a risk to be ALARP it must be possible to demonstrate that the cost involved in reducing the risk further would be grossly disproportionate to the benefit gained.
- API – American Petroleum Institute
- Business Critical Element - A Business Critical Element is any item the failure of which would cause, or contribute substantially to the loss of revenue of the production facility.
- Corrosion Circuits - These comprise piping and equipment of the same material of construction and operating under the same corrosion conditions, so that they would be expected to have the same degradation mechanisms.
- Corrosion Risk Assessment (CRA) - Corrosion Risk Assessment is the overall process of risk analysis and the evaluation of the likelihood of corrosion and the consequence of failure.
- Consequence - The outcome of a failure. This is expressed in terms of safety to personnel, economic loss, and damage to the environment.
- Deadlegs - sections of process piping that have been isolated and no longer maintain a flow of liquid or gas.
- Degradation mechanism - The means by which a component degrades, such as by Internal and external corrosion, erosion, fatigue, Stress Corrosion Cracking, chemical processes or metallurgical processes affecting the material condition or properties.
- Environmental Critical Element - An Environmental Critical Element is any item the failure of which would cause, or contribute substantially to, the pollution of the environment.
- Failure Modes - The manner of failure. For risk based inspection, the failure of concern is loss of containment of pressurized equipment items. Examples of failure modes are small hole, crack, and rupture.
- GOR - The gas/oil ratio (GOR) is the ratio of the volume of gas that comes out of solution, to the volume of oil at standard conditions.
- Hazard and Operability (HAZOP) Study - A HAZOP study is an analysis of failure modes and their cause and effects. HAZOP studies use systematic techniques to identify hazards and operability issues throughout an entire facility. It is particularly useful in identifying unforeseen hazards brought about by design or introduced into existing facilities due to changes in process conditions or operating procedures.
- Hydrocarbons – organic chemical compounds of hydrogen and carbon atoms forming the basis of all petroleum products. They may exist as gases, liquids or solids. An example of each is methane, hexane and asphalt. To all intents and purposes the terms “hydrocarbons,” “petroleum” and “oil and gas” are interchangeable.
- KPI - Key Performance Indicators
- MTBF - Mean Time Before failure
- P&ID – Piping and Instrumentation Diagram

- PFD – Process Flow Diagram
- PPM - Parts Per Million
- Probability - The likelihood that a failure will occur, measured annually. Probability can vary between 0 (zero) - no likelihood at all and 1 (one) – guaranteed failure.
- Mitigation - Limitation of any negative consequence or reduction in probability of a particular event.
- Risk - Defined as the combination of probability of failure and consequence. The highest risk is mostly associated with a small percentage of plant items. Risk based inspection procedures can be based on either qualitative or quantitative methodologies. Qualitative procedures provide a ranking of equipment, based largely on experience and engineering judgment. Quantitative risk based methods use several engineering disciplines to set priorities and develop programs for equipment inspection. It is normally expressed with reference to safety, economy and environment.
- RBI – Risk Based Inspection refers to the application of risk analysis principles to manage inspection programs for plant equipment. The ultimate goal of RBI is to develop a cost-effective inspection and maintenance program that provides assurance of acceptable mechanical integrity and reliability.
- Safety Critical Element - A safety Critical Element (SCE) is any item the failure of which would cause or contribute substantially to, or a purpose of which is to prevent, or limit the effect of, a major accident.
- Sour Service – Used to describe oil which contains a significant amount of H₂S.
- Sweet Service – Used to describe oil which contains a significant amount of CO₂
- SCC – Stress Corrosion Cracking

References

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- **API RP 75: Recommended Practice for Development of a Safety and Environmental Management Program (SEMP) for Offshore Operations and Facilities**
- **API 510: Pressure Vessel Inspection Code-Inspection, Repair, Alteration, and Rerating**
- **API 570: Piping Inspection Code-Inspection, Repair, Alteration, and Rerating of Inservice Piping Systems**
- **API RP 571: Damage Mechanisms Affecting Fixed Equipment in the Refining Industry**
- **API 579: Fitness for Service**
- **API RP 580: Risk Based Inspection**

- **API RP 581: Risk Based Inspection Technology**
- **API 653: Tank Inspection, Repair Alteration, and Reconstruction**
- **ASME B31.3: Process Piping Code**
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- **Capabilities and Limitations of Nondestructive Evaluation Methods for Inspecting Components Beneath Thermal Protection Systems – The Aerospace Corporation** (free to download)
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- **UK HSE: Guidance on Risk Assessment for Offshore Installations** (free to download)
- **UK HSE: Key Programme 3 (KP3) Asset Integrity Programme** (free to download)
- **UK HSE: Key Programme 4 (KP4) Ageing and Life Extension** (free to download)
- **UK HSE: Offshore External Corrosion Guide** (free to download)

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