Ageing Plants – Corrosion is the Real Enemy but there are other problems

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Abstract

Much has been written about the ageing of plants and the concerns have been raised on the useful lifespan of industrial plants.

This has arisen because most companies have had to prolong the deployment of their facilities beyond their intended life due to:

1) Increased growth worldwide increasing the demand for products particularly in developing countries.
2) Prohibitive costs for new replacement plants.
3) State employment requirements.
4) Sales (often complete plants) to buyers.

The main concerns are corrosion, erosion, wear and tear, obsoleteness.

Corrosion is the real enemy costing owners millions per annum in every country. It is one of the most potentially damaging losses to any commercial, private, or industrial property. An estimated one-sixth of all new worldwide steel production is used to replace corroded metal - corrosion problems are increasing in frequency and severity, not decreasing. The reasons for this are declining material quality (cheaper less sustainable products are demanded for plants under design/construction) and inadequate corrosion control engineering combined.

The corrosion of steel piping/fittings/vessels/towers/drums/heat exchangers and so on is a continuous and virtually unstoppable process. The end product is commonly the formation of rust which is simply the result of an electrochemical reaction through which the higher energy-processed metal is slowly reverted back to its naturally occurring form: metal ore. Many high-corrosion scenarios result from years of problematic conditions that have gone unaddressed not only in process areas but also in the secondary support systems such as utilities and offsites. They can be inherited from a previous owner or operator who was not effective at recognizing/controlling a corrosion problem.

Apart from fire, corrosion represents the most serious threat and monetary loss to any facility, causing decline in heat transfer efficiency and plugged piping to pinhole leaks and temporary shutdown for repairs. If there is a loss of containment due to component failure, there could be a fire/explosion and also the potential for a Vapour Cloud Explosion (and catastrophic loss). Corrosion also causes flood damage, loss of production, and personal injury.

This paper describes 30 types of corrosion/erosion which can be found in ageing industrial plants and suggests the remedial actions that are usually required to correct the problem.

Key Identifiers (KIs) are presented which lead to plant failure such as changes in operating conditions, more aggressive feedstocks, Corrosion Under Insulation (CUI), inadequate inspection regimes, material mismatches, overdue retirements and obsoleteness.

A review of some of the other common problems found in many types of onshore/offshore ageing structures, process/energy plant equipment, utility systems, offsites, fire protections and pipelines are detailed in this article and the requirements for a rigorous inspection program to continuously assess their physical condition.

Some plants are 'mothballed', and this needs very careful steps to avoid corrosion occurring (use of oxygen free atmospheres such as Nitrogen blanketing and desiccant to absorb free water) and the sealing of flanges and openings. Externally the corrosion could occur from rainwater or the local environment. Unused plant segments often become increasingly unreliable, can lead to serious incidents and should always be tested before re-commissioning.

Plant ageing(1)(2) can also occur through thermal cycling caused by too many start-ups/shutdowns per annum, plant location (coastal plants tend to suffer higher corrosion rates than in-land facilities due to the saliferous environment and humidity) or the effects of nature such as microbiological attack, and events such as seismic damage caused by earthquake, flooding, windstorms and so on. However, there are also deteriorations caused by variance in soil conditions, stray electrical currents, biological effects (pipelines); stress (all plant), low point water accumulation and unstable flow regimes.

Lifespan Technical Examinations (LTEs) are becoming common place to establish the possibility of extending the operation of a plant. These often make recommendations to the plant to improve its integrity. Mature sites have some key advantages such as generous equipment and pipework thicknesses (overdesign) and use of high-quality reliable materials although spares availability is obviously a concern.

This paper also considers retirement criteria such as inefficient production, high maintenance costs (corrosion and erosion) and safety issues. Downgrading of system pressures have to be made when pipework shows thinning, and this can also occur in pressure vessels with costly total replacement. The use of clamps is discussed which have either been used to seal leakage or are rated for full pressure.

Four Case Studies are provided to demonstrate classic failures; the risk of mixing old obsolete equipment with newer plant leading to error in maintenance; gradual tank corrosion leading to major environmental pollution; operational limitations posed by retaining antiquated instrumentation and failure to modernize; particulate or dust explosions caused by erosion.

The effect of the current pandemic will be discussed.

1.0 Ageing Plants

Most high-corrosion scenarios result from years of problem conditions that have gone unaddressed. Often, it is inherited from a previous owner or operator who was not effective at controlling a corrosion problem, and/or was obviously not concerned.

Figure 1– Old Power Plant showing Corrosion

The current COVID pandemic has created five problems: -

1) Unavailability of international specialists to check site equipment for problems and a backlog of tasks to be completed.
2) Supply chain interruption for all types of equipment, components and materials, replacement parts and spares.
3) Maintenance/Inspection Deferrals or scope reductions.
4) Some owners have had to mobilize an extra contractor workforce to cater for teams required to isolate, illness and failure to attend their sites.
5) Delay in modernization programme implementation.

2.0 Inspection Data is the Key

All processing/utilities/energy/storage/pipelines/loading/unloading plants should always undergo a rigorous inspection program for to continuously assess their physical condition. This will entail: -

1) Maintaining comprehensive inspection and maintenance records[3] which can be trended to illustrate changes in corrosion, erosion, wear, and tear. Typical areas for examination are tower trays and internals, lined or clad vessels, pump impellors, compressor and turbine rotors, seals and bearings, high-temperature services such as tubes in furnaces/boilers/exchangers, all types of pipework, pipelines and trunklines. Typical NDT techniques which are suitable are: Visual Inspection, Ultrasonic Thickness Measurement, Ultrasonic Phase Array, Radiographic Testing., Measuring Vibration, Penetrant Test.

2.1 Other Criteria for Investigation

2) Noting the design basis of devices which generate heat (such as control systems, electrical equipment, instrumentation). Climatic changes may increase the temperature in enclosures/rooms and create a need to install more HVAC system capacity to prevent overheating.
3) The adequacy of cooling systems (water, air etc.) can deteriorate overtime due to corrosion, fouling, wear and tear and this needs to be evaluated.
4) Pump wear can reduce the performance (e.g., Firepump wear means that the design flow cannot be achieved).
5) Methods of pipeline inspection need to be considered where intelligent pig inspection cannot be used for buried locations such as through tunnels, submerged under water. Guided wave and ultrasonic testing systems can be deployed.
6) RBI (Risk Based Inspection) cannot be used for reducing maintenance unless complete certainty is known that similar systems are in identical condition.
7) Subsidence and collapse can occur through drying out of foundations. Regular inspection using theodolite measurements are advised to discover movement.
8) Damage will occur if the site is subject to earthquake, windstorm, cyclones, hurricanes, volcanic ash deposition, flooding or tsunami. Following any natural peril event, the plant should be checked for any form of damage.

2.2 Typical Trend Calculations

T_A-T_{Min} = Thickness Remaining (mm) where T_A is the actual measured thickness and T_{Min} is the minimum required to meet the design conditions.

R_D = Rate of Wear = mm/year

So $(T_A - T_{Min}) / R_D$ = Remaining life (years)

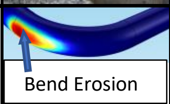
Many plants incorporate a corrosion/erosion allowance (usually 3-6mm in pipework or vessels) which supplements the design thickness. When this has been lost there is a no safety factor, and the plant will be able to meet the design conditions providing there is no further deterioration. Can the plant cope with the Maximum Operating Working Pressure (MOWP)? If not, then replacement is required.

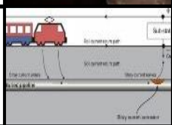
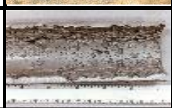
3.0 Corrosion/Erosion Types

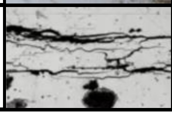
The main problem is localized corrosion/erosion where this may be in a relatively small section/area. If this is the case, then inspection points have to be relied upon to identify them[3].

Guidance is given in the codes API 570 and 574 to select inspection points such as:

Figure 2 – The most common types of failure modes for corrosion/erosion/chemical attack

Inspection Point Suggestion	Most Common Failure Cause	Example	Repair Action
Injection or Mixing point	Turbulence generated with change of fluid composition and/or temperature results in damage mechanisms to inside of pipe (e.g., corrosion)		Wear patch or thicker pipe specification before and after the injection/mixing point. Good nozzle design to avoid direct impingement.
Stagnant Locations, Dead Legs	Water/chemical corrosion usually in Acidic or Alkaline Conditions, light rust congregating in dead legs, low points		Generate a register and then elimination of dead legs by reconfiguration of pipework. External sleeving, spot repairs, clamps. Sweeping of low points using pigging or flushing. Often complete section replacement
Insulated Surfaces External Corrosion Corrosion Under Insulation (CUI) Missing Insulation	Entrapped condensed water results in CUI - often not detected. Inadequate moisture barrier allowing water to ingress to pipe surface creating a damp condition or pipe sweating		Remove insulation and repair pit corrosion – use wire cage as personal protection insulation for hot/cold surfaces where heat loss/gain is not a significant concern. External sleeving, spot repairs, clamps & replacement insulation
Soil-Air Interface. Degraded External Coatings External Corrosion – surface pitting.	Breakdown of wrap at ground level and Loss of Integrity of insulation, PE/PP wrapping damage.		Re-instate wrap after inspection of pipework at the interface. Replace coatings New section in extreme cases
Service Specific and Localized Corrosion	Mould Causes Corrosion – deep localized pitting can occur. Microbiological Influenced Corrosion (MIC) – sulphuric acid formation attacks the pipework		Upgrade materials for vessel cladding or piping for the process. Eliminate stagnant points. External sleeving, spot repairs, painting New section in extreme cases
Erosion/Abrasive Wear – Check where fluids contain solids	Solids in fluids which have a higher hardness create wear or grooves. High velocities in condensing steam systems.		Wear plates. Thicker Piping Eliminate particles reaching lubricated surfaces
Weathering – externally exposed to Atmospheric Conditions	Adverse weather (rain, humidity, snow). Nitrates or sulphates in air. In marine areas the environment will contain chlorides.		Paint protection including primer coat, shelter equipment from weather. In extreme conditions equipment may be enclosed in a building.
Corrosion beneath lining and deposits or plugging/fouling	Cladding/lining failure Inadequate cleaning/washing techniques allowing material to congregate and localized attack		Metal spray can be used twice after this replacement parts are needed.
Fatigue cracking – high stress points	Component beyond useful life, Thermal Cycling Droplet impact on blades of turbines		Nearly always requires replacement of parts

Creep cracking	Concrete structures subject to freeze/thaw cycling Piping distortion		Repair structure with infill Buckled piping will have to be replaced.
Brittle fracture	Crack growth from stress. In severe cases the item fails catastrophically		Replacement of items/parts
Hydrogen Induced Embrittlement	Diffusible Hydrogen released by poor welding or incorrect welding materials. Increased H2 partial pressure or more severe conditions introduced.		Replacement of parts Often difficult to detect
Ductile fracture	Plastic Deformation		Reduce stress loads and replace damaged areas.
Freeze damage	Unsuitable materials for climatic conditions or no winterization installed.		Replacement of parts. Often the complete item.
Sulphide Stress Corrosion	Inadequate materials or incorrect heat treatment – difficult to identify.		Replacement of parts. Often the complete item.
Temperature Embrittlement	Long term exposure causes degrading of toughness of the material		Replacement of parts
Galvanic Corrosion	Mismatch of materials causes electrical differential destroying one metal – notably at valve connections/fittings/ nozzles.		External sleeving, spot repairs, clamps, or metal change. Insulation joints, make sure Bolts, nuts and washers are the same material
Stray Currents	Caused by electrical line in close proximity (eddy currents) setting up electrical cell effect		Removal of electrical source External sleeving, spot repairs.
Steel to Steel Electrolysis	Pipe supports and hangars – direct pipe to support metal contact		Install PTFE or equivalent as a barrier under pipe on support
CO2 Corrosion (sweet)	Formation of Carbonic Acid and then iron carbonate which thins the pipe wall		Corrosion inhibitor Upgrade of materials
H2S Corrosion (sour). With water present forms iron sulphide which initially protects the pipe inside surface	But can break down causing severe pitting. Release of atomic H2 can then congregate into pockets and cause blistering and SSC.		Corrosion inhibitor Upgrade of materials
Imperfections Corrosion - surface pitting	Poorly welded or unprotected joints, grooved pipes		External sleeving, spot repairs
Chloride Corrosion	Impurities in plant and external atmospheric conditions		Often complete section replacements
Cooling System/Heat exchanger Corrosion – internal corrosion	Internal corrosion can lead to tube failure and loss of performance		Tube plugging, spot repairs, corrosion inhibitor, anti-fouling chemicals, improved cleaning
Stress Corrosion – weld or bend failure	Incorrect pipe stress at anchors or poor pipe configuration.		Remove stress points, usually requires line replacement

Pipe Thread Failure - Corrosion	Caused by weakness at joint corroding (less metal thickness in screw fitting up to 50% cut away)		Eliminate screw fittings
Boiler/furnace tube failure due to corrosion at bends/joints	Fouled tubes, poor decoking, velocities too high after expansion of plant		Replacement of tubes
Cavitation Corrosion	Bubbles of gas formed after pressure drop which then collapse on surface of pipework		Correct pump NPSH to eliminate vaporization. Increase downstream metal thickness after let-down valve or choke valve
Crevice Corrosion	Accumulation of corrosive material in imperfections, gaps around bolts holes, under washers		Spot weld repairs. Check and replace corroded bolts, washers, nuts
Mercury Attack on Aluminum	Mercury in feedstock can end up downstream and attack exchanger plates or nozzles		Replacement parts

4.0 Critical Aspects which can lead to Failures and Remedial Measures

4.1 Vessels/Pipework

Metallic equipment and its piping are subject to both external and internal corrosion[1][4][5]. Externally this is caused by acidic pollution carried in the atmosphere which condenses on the pipework or vessel (often under insulation). CUI (Corrosion Under Insulation) has received significant attention in the past 20 years but (Corrosion Under Supports) CUS is also a serious concern. Internal corrosion will occur whenever acidic, or alkali conditions can occur with oxygen and/or water is present.

Pipe repairs take on various forms, ranging from temporary clamps to the replacement of entire piping systems. The problem with allowing too many clamps on a plant is that they all require regular inspection and maintenance to ensure there are no leaks and they often cannot be removed until the next turnaround which may be 3-6 years for some processes. Corrosion coupons have some benefit but are not totally reliable in reporting the complete picture[2]. Weld failures are usually associated with high pipe or nozzle stress.

There are two very positive aspects of mature plants:-

1) Vessels were often made with generous steel thicknesses and many therefore have long lifespans. Studies on lifetime extensions indicate that 10-15 years is often possible on some pressure vessels even after 40-years' service.
2) Steel quality was often a high priority as opposed to cost thereby reducing the effect of corrosion.

Pipework remains the main concern as this was normally based on the design conditions plus corrosion allowance, however, increasing flowrates in expansions or revamps and more severe process conditions can lead to faster erosion and reduced design margins. Bolting also can deteriorate over time and also the use of incorrect bolts, nuts (size or material) is a concern. Old gaskets often leak and need to be replaced (tightening up may damage the fitting).

4.2 Valves

More mature plants tend to have a lower level of automation, in particular, fewer remotely operated shutdown valves to isolate major inventories. Also, some block or control valves can only be maintained by removing integral bolts (exposing the internal line conditions) and this has resulted in accidents (Case Study No.1). Also, a number of stem failures have been noted, caused by acidic material leaking past seals.

Valves which are not regularly opened/closed such as ESD/relief valves/blowdown will 'stick' in some services and fail to perform. Except for full bore valve types, the valve internals will provide a restriction around which contaminants, solid particles can accumulate.

Power systems' substations switching valves (particularly oil-filled mechanical devices) can fail without regular testing and maintenance.

Reliable valve suppliers are important to avoid early change-out or repairs. Selection of an appropriate valve trim material for a specific due is essential particularly if the service can experience erosion. Valves which cannot be locked in position (such as flare lines to PSVs) should be replaced so that a LOTO systems can be enforced (Lock Out Tag Out).

4.3 Rotating Machinery[6]

Erosion is caused by high velocities/and or solid materials (particularly with a change of direction such as at vessel entry or bends). This will cause localized metal thinning. It can be resolved by installing wear plates (sacrificial material or an extra thickness).

Steam turbines are particularly susceptible to blade damage from steam containing water droplets and contaminants such as chlorides.

Sour gas compressor internals should be high grade steel suitable for the duty.

Blenders for hard metallic particles can be subject to erosion which produces fine metallic airborne dusts which will burn and/or explode if the dust removal system is not fully operational or absent (refer Case Study No.4)

Pump Seals – many older facilities relied on single mechanical seals for all duties including light hydrocarbons. Modern facilities are now constructed using double seals to reduce the likelihood of accidental release (note: a major source of fire and explosion in hydrocarbon-based plants is pump seal failure).

Compressors Seals - dry gas seals have become the normal. Double dry gas seal is a preferred system when operational safety is crucial: the secondary seal is a back-up seal (normally running at a lower pressure) that can handle the full pressure in the event of a primary seal failure. Double seal arrangements are utilized when product leakage to the atmosphere is unacceptable or for low pressure applications.

With old pumps or compressors, the conversion to double seal is often impossible and new equipment has to be installed.

Supplier quality was often very high in the equipment purchased for mature plants; the only problem appears to be spares availability.

4.4 Vibration Monitoring

Older plants may not have the most sophisticated vibrational monitoring equipment, relying on portable devices for checking pumps, compressors, turbines[6]. Vibration causes weld stress and can enhance corrosion activity. It is also a more common than expected due to changing operational parameters and/or ageing of components.

The main problems are incorrect alignment of pump/compressor rotors, poor pipework design (inadequate stress analysis), slugging of gas lines, cavitation, restricted expansion/contraction which causes buckling. Absence of dampeners.

Surge analysis is required for pipelines and good stress analyses. One solution for pipeline surge control is to break the flow into a surge vessel, if delaying the closure of line valves cannot solve this problem. Hammer (where the energy of the fluid moving in the pipeline is applied to the pipe wall and its valves) can cause major problems such as deformation and movement off supports.

4.5 Electrical Systems[14][15]

Mature plants and distribution systems often used paper/oil filled cabling which slowly decayed over time. This resulted in heat generation which accelerated shorting and ultimate failure. Most of these systems have been replaced by modern cabling such as XLPE. Also, older types of switch gear and relays have been phased out. Although the equipment has a long-life span again the obtaining of spares is an issue.

The need for a reliable power supply system is mandatory. A mature site should be checked for power supply to ensure it shuts-down safely avoiding any loss of containment and can then be re-started from a known status. The conversion of relay-based systems to electronic is a difficult piece of work and needs careful planning.

4.6 Instrumentation[12][14]

Pneumatic/mechanical instrumentation has been phased out almost completely and replaced with electronic systems. However, some older sites may still operate with the following measurement systems: -

1) Float gauges for storage tanks – which need to be adequately maintained (refer Case Study No.3).
2) Weight balanced valves.
3) Chart ink temperature and pressure recorders.
4) Pneumatic valve actuators.

Although these systems are considered primitive, they have often worked for many decades and have only been replaced by obsoleteness of spares. DCS[16] brings many advantages such as the design of ergonomically attractive control rooms, space saving and advances in instrumentation technology. Often no voting system was installed which can lead to spurious trips[13][14][17].

4.7 Firewater Systems

Systems in older sites may have been designed with poor deluge coverage (e.g., sphere or bullet wettage). There are guidelines in NFPA for the water rates in litres/m^2/min and the items to be deluged. Firewater systems often leak though corrosion as the headers are buried underground. Modern sites tend to use non-metallic foremains but these of low strength. One aspect which should be evaluated is subsidence and collapse of ground through instability particularly from an earthquake event. The firemain at Izmit refinery was shattered into 4000 pieces (17th August 1999 – 7.6 magnitude).

4.8 Passive Fireproofing

This decays with time due to moisture ingress (particularly where freezing conditions occur during winter). The ice formed expands and lifts the passive fireproofing away from the structure – the trapped water causes structural corrosion. There is some progress in using different materials such as mastics in place of the concrete, but the compound has to be non-flammable, must not melt under severe ambient conditions or heat generation, and be cost effective.

4.9 Obsoleteness

This has accelerated with advances in electronic systems. A good DCS system will often last less than 10 years even when upgrades are applied.

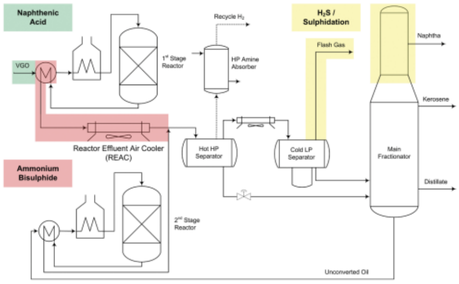
Some in-line instrumentation cannot be rectified unless the plant is shutdown (with extended periods between turnarounds this has become a concern).

It is interesting to note that some older systems still in use today have, in fact, a higher reliability than some of their modern counterparts as 'they were built to last'.

5.0 Poor Material Selection

Cheap materials used for corrosive services (e.g., sour water strippers processing water containing acetic acid are often constructed from Carbon Steel). Where the acid condenses will eventually lead to vessel failure.

Poor quality steels with high impurities represent an opportunity for corrosion to progress. Change of process conditions which cause accelerated deterioration (more severe temperature, pressure, acidity, alkalinity). High sulphur, acidic or salty feedstocks require material upgrades to avoid rapid deterioration.



The use of material selection process/utility diagrams or Corrosion Identification PFDs/UFDs is highly recommended. In most mature plants the corrosion areas are known by the operator/owner.

Left is a typical flowsheet marked up to indicate expected high corrosion areas.

Figure 3 – High Corrosion Areas Identified on PFDs

5.1 Difficult Plant Areas

Difficult plant areas e.g., vertical pipework for overhead lines which can corrode but cannot be easily inspected due to the elevation and compactness against the vessel top section.

A Dead Leg Register for a site might contain 15000 items which should be eliminated.

Difficult Areas to inspect – unfortunately these areas may experience the highest corrosion rates

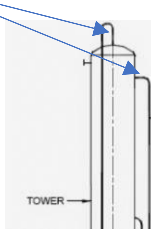


Figure 4 – Tower Top

6.0 Pipelines

Pipelines are particularly vulnerable when they are subject to: -

a) Inadequate Cathodic Protection (none fitted or failure to operate)
b) A change of soil conditions along the route
c) Stray electrical currents close-by
d) Biological Effects
e) Water Crossings, Beach approaches
f) Stressing
g) Blockage from hydrates, wax
h) Low points allow water accumulation on the bottom segment
i) Gas lines may be subject to 'slug-flow' which occurs after cooling of the gas and formation of liquid.

Also, in mature sites there may be buried lines and accidents have occurred when excavating 'live lines'.

Repairs using clamps and wrapping which vary enormously. A simple G-clamp used to squeeze the pipe to prevent leaks, sealing compound and wraps are used in low pressure services. Welded sleeves can be used where the repair can take the MOWP, but these are expensive (a 48-inch line 100 bar pressure rated welded sleeve might cost USD 500000).

All piggable pipelines should be checked by an intelligent device every 5 years. The device travels along the route to find wall thinning and once this is ascertained to be a risk to the design pressure the pipeline should be re-rated and/or repaired. Pipelines are often constructed using 23 m lengths so a section can be removed and replaced.

Some operators use patch welded repairs which is not recommended for pressurized services – even for water services. Patch welds will corrode at the welded edge and are not completely reliable.

7.0 Control Rooms and Substations

Upgrading existing facilities requires a thorough study to ascertain the following:-

1) The true blast resistance of the building in bar which may vary from 0-0.7. Explosion prediction models can then be used to generate pressure contours (allowing for an accidental gas release, cloud drift and delayed ignition). If the predicted overpressure is larger than the building design parameters, then the building will not withstand the explosion forces. Re-constructing the building may be impractical (cost prohibitive) so the options will be relocation to a less hazardous area or construction of an annex which will be able to survive a blast situation. If DCS is replacing an old control system, the space required is often considerably less and this may be a suitable option (control room personnel safety and systems protection).
2) Control Rooms, substations and plant buildings with poorly sealed non-gas tight doors and cable transits expose ignition sources and create hazardous enclosures. These deficiencies are often found on ageing plants and should be corrected. Positive pressurization inside each building will prevent toxic and/or flammable gas ingress.
3) Poorly designed HVAC systems encourage gas ingress and do not remove heat generation from electrical devices causing them to overheat. Often the design did not cater for heat dissipation and the high ambient temperatures experienced at various locations in the world. Buildings should have clean air intakes facing away from the process and also dampers activated by in-line gas detectors. If the building is under closed air condition, then the heat rise should be calculated to find out whether the equipment can still function properly.
4) Use of polyurethane sealers for cable entries is to be avoided – this type of sealant is flammable and porous (with age).

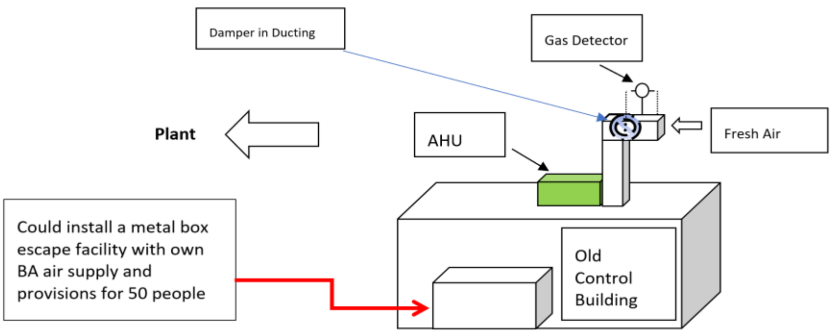


Figure 5 – Control Building Requirements

8.0 Boilers/Furnaces[7]

Boiler/furnace condition deterioration begins with loss of firebox integrity, and this can cause hazardous situations as air ingress results in the formation of explosive gas mixtures (start-up) and obviously tube condition – pin-hole leaks, stress corrosion at hairpin bends, cracking of tube walls caused by over-firing. There is a useful life standard (20,000-60,000 hours before replacement is typical).

Cross connected flue gas ducting is often found which can lead to operational problems for the stack and furnace and also increased lining corrosion.

Operators should make sure that there is enough dilution steam capacity to lower temperatures and prevent damage.

Sometimes older plants are found with primitive burner management systems which have poor interlocking of safety devices. All fuel lines should have double isolation (not using the control valve as one blocking valve).

9.0 Heat Exchangers

Shell and tube exchangers can be subject to fouling, and this creates an environment for plugged tubes, corrosion and/or erosion.

Condition of stab reboilers (flanged mounted on column) is also a concern as the tubes often develop unnoticed failures and the design cost saving is not warranted.

Plate exchangers are often noted to develop leaks with ageing. They offer a neat space saving solution in some services but are not as robust as shell & tubes designs.

Air coolers have poor mechanical strength and may not be robust enough for any significant changes in temperature or pressure (when revamping the plant).

10.0 Flare/Vent/Blowdown

Older plants often do not have any spare capacity in their relief systems so connecting more or increased relief loads requires expansion of the collection system. There is some benefit in using balanced pressure safety devices to cater for higher back pressures.

These systems are also subject to slow corrosion caused by sulphur/chloride deposits condensing in the pipework. Often material selection needs to be upgraded in plants with acid gases. Turning to Incoloy for flare headers is extremely expensive.

Block valves (locked open) often corrode (liquid accumulates at the valve), and they need to be repositioned (or rotated) to eliminate pockets) (refer API codes).

Relief devices including pressure relief, bursting discs can also fail due to worn out parts or fouling, it is useful to run a pre-pop test on all valves and produce a schedule of failure numbers. This should be lower than 1% but if it is up to 10% - increased frequency of testing is required (i.e., shorter time intervals between inspections). Testing should always be carried out on the 'as found condition' not after cleaning up.

Some older sites have process areas, spheres or bullets which are not connected to a flare relief system. It is a safer option to connect to a flare system for relief cases and environmentally better. There is often no or limited duplicity in older sites. The reason for this is that turnarounds were more frequent, and these were then serviced every 2 years. In modern units some plants run in excess of 3 years between turnarounds. It is not recommended to allow any PSV to remain in place over 36 months between tests.

Relief caseloads should be re-examined to ensure the relief valves are of sufficient capacity versus the latest codes.

Blowdown (depressurization systems) are usually designed to API 521 where the pressure should be reduced to 50% operating in 15 minutes or 7 barg. The blowdown loads are split into fire zones (segments) so that a phased plant shutdown will not overload the flare system.

11.0 Drains/Sewers[9]

Problems occur with sludge or blocked gullies. In one case in South America the owner decided to excavate their sewers after 60 years' operations – there was over 600 tonnes of hydrocarbon sludge/soil in the sewer.

Rainwater drainage on mature sites should be checked when pooling occurs as this indicates the laterals are blocked with silt. If the plant does not drain the water will create a humid atmosphere and enhance external corrosion of the plant and damage to the passive fireproofing.

Besides foliage growing in drainage gullies other debris can accumulate such as gloves, plastic, solid product and so on. A flow test (using firewater) will determine blockage points.

12.0 Offshore Facilities/Jetties

Marine facilities require special attention – due to the high risk of corrosion from chlorides and water interfaces. Uninterrupted painting coats are required, neoprene sleeving for jacket legs extending 3 metres above the sea level and below can be used.

Marine growth (barnacles) which form a thick layer will increase the drag around the structure. Unfortunately, due to river and ocean pollution many facilities can suffer blockages including the firewater pump caissons. Seawater/river water for cooling must be equipped with filtering systems which are capable of removing trash.

13.0 Water Systems[11]

Any metallic system which handles, processes or stores water in any form will corrode. The main concern is that these areas are usually left until there are flooding issues because water is not deemed a hazardous substance. By the time rectification is applied the system can often be beyond repair.

Many operators are deploying polyethylene or polypropylene piping:

Mechanism	Failure Cause	Repair Action
Internal Corrosion – resulting in deep pitting	Acidic or Alkaline Conditions, Free water promote corrosion, Oxygen ingress, light rust congregating in dead legs, low points	Low pressure systems can be replaced with PE or PP
External Corrosion – bare surface pitting	Weathering (rain, snow), Humidity or water spray causes wet conditions, Change of soil line conditions for buried lines	Low pressure systems can be replaced with PE or PP

The advantage of substitution to polymer material is the elimination of corrosion (non-acid services, moderate temperatures and pressures) but these materials do not have high strength and can be damaged by vehicles being used on-site (cranes and maintenance vehicles).

14.0 Leak Detection on Pipelines – basic material balance devices cannot pick up small leaks due to accuracy limitations. Significant leakage is detected by pressure loss or gas detection. There are guidelines for re-pressure testing. Attempts to counteract loss of pressure by increasing flow is the wrong selection (reference Ufa LPG leak 4th June 1989 where trains ignited an LPG leak in a valley).

15.0 Fire/Gas Detectors – these should be regularly tested and replaced as the detector often becomes poisoned by atmospheric pollution. Many older sites have ‘common fault’ fire and gas alarms which indicate a malfunction but do not identify the precise location (detector number). It is interesting to note that newer designs often have twice as many detectors in the field than older designs.

16.0 Atmospheric Storage Tank Floor Plates Corrosion

Atmospheric Tanks corrode at slow rates – usually from water being present over the floor plates and this causes pitting (Case Study No.2). This is accelerated by floor plates being in contact with the underlying soil and moisture (absence of insulating barrier). API recommends that an internal inspection should be carried out on a 10-year cycle unless inspection data dictates otherwise.

Roof corrosion occurs on unpainted surfaces and underside where condensation deposits chemicals such as sulphur. Tank shells are more resilient but there can be corrosion at the circumferential weld between the shell and floor plates.

Scanning of the floor and annular welds should reveal anomalies but even this is not 100% reliable. Leaks for products are often detected by site personnel (smell or observation).

Refrigerated tanks often are double wall with insulation between. The insulation deteriorates with time and needs to be replaced or supplemented. This can often be seen by ice formation on the outside wall in areas where the insulation is underperforming. Double or triple walled tanks should not be de-commissioned unless they have exceeded their approved lifespan or problems have been detected. Warming up and re-cooling stresses the tank welds and may contribute to failures. Normally these tanks are in clean/dry service so the inner tank should not corrode.

Cup tanks (which have an outer bund for spillage retention) should always have annulus drains for removal of rainwater.

Inspection of tanks is a difficult task requiring careful scanning of all areas. The use of polymer-based coatings for the bottom 2-3m is often helpful in controlling water-based corrosion.

17.0 Pressurized Storage

Spheres and bullets are more resilient to corrosion. This is because they are usually handling water-free clean products and the product vapour pressure maintains an oxygen free environment. The main concern is when these items are insulated, and the storage temperature is lower than ambient. Water condenses under the insulation resulting in pit corrosion.

Particular attention needs to be paid to the condition of the shell welds (completeness and any corroded areas), the leg joints (where they are attached to the shell) – a deflector plate can be installed. Inspection should check for corrosion under the fireproofing coating to avoid collapse (some spheres develop longitudinal cracks in the legs due to corrosion caused by trapped water). Elimination of flanged connections and small fittings below the liquid level should be considered.

Mounded bullets (buried in soil) are often deployed to avoid the risk of Boiling Liquid Expanding Vapour Explosion (BLEVE); however, inspection is difficult to find corroded areas.

BLEVE (Boiling Liquid Expanding Vapour Explosion) risk can be eliminated by drainage away from underneath sphere or bullet shadow and routing spillage to an open impounding pit.

18.0 Steel Structures[8][9][10]

All steel structures will eventually corrode normally at high stress points, welds, bolted connections and at ground interfaces. These should have been adequately painted during construction and also regularly repaired. When revamping a mature site, the weight loading may increase, and additional supports are required.

Most warehouses are built using a structural frame and it is the roof which is likely to suffer weathering and/or corrosion. Many occupied buildings are built of reinforced concrete and have a long lifespan.

19.0 Caverns/Underground Facilities

Caverns and undersea voids are suitable for storage of hydrocarbons, waste gases. However, they have a finite lifespan before leakage occurs.

20.0 Dust Accumulation

Many processes generate dust and in confined locations this may become airborne and be ignited to cause severe explosions. (Case Study No.4). Dust accumulation particularly in confined areas such as buildings is always a risk and a health hazard.

21.0 Concluding Remarks

This paper illustrates some of the key aspects in assessing the condition and corrective measures for ageing plants.

Areas which require particular attention are:

- Condition of the facilities in particular the remaining thickness of all pipework, vessels, towers, drums, internals, and the expected lifespan. Inspection data is essential to assess the plant status.
- Any record of thermal cycling - too many startups /shutdowns – a new ethylene cracker which experiences 20 SUs or SDs in its first year will have aged 10 years.
- Exposure to abnormal process conditions (severe pressure or temperature and/or change of composition or flow rate of processed fluids). This may alter the erosion/corrosion rates significantly.
- Weathering – particularly on coastal plants (jetties and structures which enter the sea; or are exposed to saliferous environments and high ambient temperatures).
- Submerged structures (such as support jackets which corrode or can collect marine growth causing drag effects).
- Flooded jacket steel structures members in offshore platforms which are subject to aggressive sea conditions and topsides exposed to increased sea wave height.

The key decision will be whether to continue operation or to retire the facility.

Retirement is usually based on:

- Declining demand for the products from the plant
- The costs to continue and the net profit

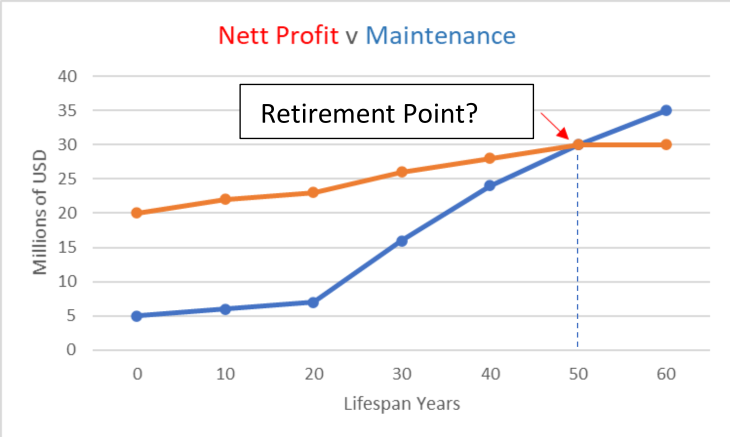


Figure 6 – Retirement Point

Once the maintenance costs including any ongoing repairs approaches the net profit it is usually time to retire the plant. Any reduction in profit (for example a declining oil reservoir with higher water production) may lower the net profit) but unfortunately maintenance costs do not go down with age.

Some plants may be energy inefficient indicating a revamp is required to recover more of the waste heat or more modern equipment which uses less energy,

Decommissioning can be expensive (removal of offshore structures) or demolishing and removal of existing plant is often demanded by authorities.

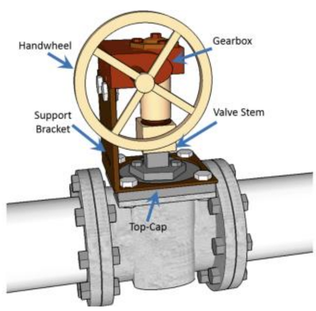
22.1 Key Identifiers

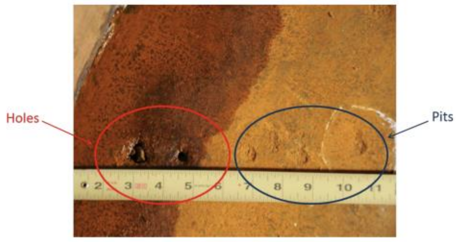
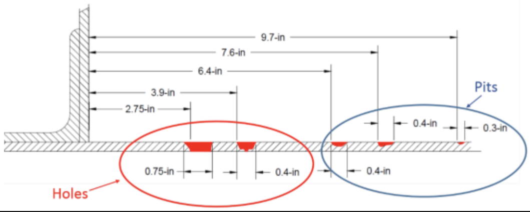
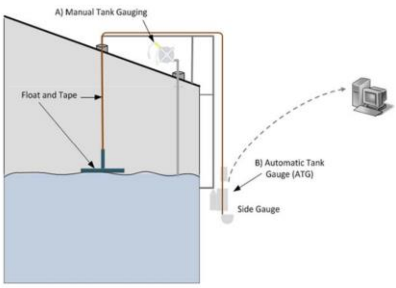
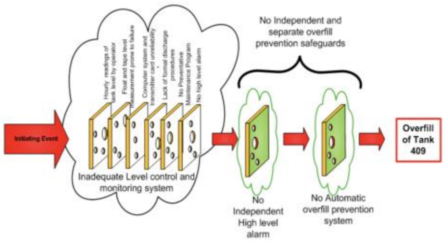
1) Change of feedstock and its impact on the existing plant. E.g., switching from a sweet crude feed to one which has high sulphur or contains naphthenic acids.
2) Change of processing conditions – higher pressure, temperature, concentration. E.g., increasing the partial pressure of Hydrogen bearing streams, solids such as sand entering the plant.
3) Inadequate inspection data. Some sites have little or no data on the condition of lines, pipelines and the equipment; vessel nozzles which may be in poor condition. Three sets of thickness measurements are needed to be able to trend the corrosion rate.
4) Poor testing regimes for valves, infrequently operated systems.
5) Inadequate 'mothballing' activities to protect unused plant from corrosion and deterioration.
6) Poor storage of delicate spare parts e.g., failure to store rotors for compressors in accordance with manufacturers' instructions.
7) Incorrect gaskets, blind plates which do not meet the pressure rating of the line.
8) Mismatch of materials particularly bolted connections. Note: the wrong bolt sizes are often found, short bolting and high stress levels caused by incorrect torquing procedures.
9) Operation of systems, items way beyond their intended working life e.g., bolted aluminum reboilers where connections have deteriorated due to the softness of the material should have been replaced every 15 years but are found to have been in place for 30 years plus.
10) Obsoleteness – non-availability of plant components – leads to failure to replace instruments which are defective (or using inferior replacements).

22.0 Case Studies

About 70% of losses occurring in industry can be traced back to corrosion and most of these are concerning pipework failures releasing flammable materials which ignite and cause serious fires/explosion. Corrosion can be prevented but this requires investment in comprehensive inspection and corrective maintenance. There are other problems such as retention of obsolete designs (which should have been replaced. Inadequate control /monitoring systems or allowing dust accumulation.

The table below highlights some well-known losses and the cause.

Event	Detail	Remark
Case Study No.1 On November 22, 2016, an isobutane release and fire seriously injured four workers in the sulphuric acid alkylation unit at a refinery in Baton Rouge, Louisiana. During removal of an inoperable gearbox on a plug valve, the operator performing this activity removed critical bolts securing the pressure-retaining component of the valve known as the top-cap. When the operator then attempted to open the plug valve with a pipe wrench, the valve came apart and released isobutane into the unit, forming a flammable vapour cloud. The isobutane reached an ignition source within 30 seconds of the release, causing a fire and severely burning four workers.		This type of valve should have been replaced or clear working instructions should have been given to the maintenance crew. Warning Signs are useful to indicate direct connections to the internal process for this type of configuration, but the best risk reduction measure is replacement.

Case Study No.2 A chemical storage terminal tank leaked in Charleston, West Virginia on 05/11/2017 and contaminated the local water supply leaving thousands of residents without clean drinking water. The 20-foot-diameter tanks were most likely constructed in the late 1930s. The cylindrical shell and cone roof were of an obsolete, single lap-riveted construction. The tanks contained a 0.25-inch lap-welded bottom that inspectors estimated to be a replacement for the original lap-riveted bottom. The bottom interior of tank 396 was found to have deep, isolated pits or crevices near the shell (side) of the tank in addition to two holes on the tank floor, approximately 0.75 inches and 0.4 inches in diameter, which were the source of the leak	  	Tank Inspection was inadequate for ageing tanks and the advanced pit corrosion was not identified. This eventually made two holes in the bottom plate allowing a toxic chemical to be released into the environment.
Case Study No.3 On October 23, 2009, a large explosion occurred at the CAPECO facility in Bayamón, Puerto Rico, during offloading of gasoline from a ship. A 5-million-gallon aboveground storage tank overflowed into a secondary containment dike. The gasoline spray aerosolized, forming a large vapour cloud, which ignited after reaching an ignition source in the wastewater treatment area of the facility. The blast and fire from multiple secondary explosions resulted in significant damage to 17 of the 48 petroleum storage tanks and other equipment onsite and in neighborhoods and businesses offsite. The fires burned for almost 60 hours. Petroleum products leaked into the soil, nearby wetlands and navigable waterways in the surrounding area.	  	Multiple physical causes contributed to Tank 409 overfill: Malfunctioning of the tank side gauge or the float and tape apparatus during filling operations led to recording of inaccurate tank levels Normal variations in the gasoline flow rate and pressure from the ship without the facility's ability to identify and incorporate the flow rate change in real time into tank fill time calculations may have contributed to the overfill. Potential failure of the tank's internal floating roof due to turbulence and other factors may have contributed to the overfill.
Case Study No.4 On 12/09/2010 in Cumberland West Virginia an explosion in the production building was caused by combustible titanium and zirconium dusts that were processed at the facility. The explosion originated in a blender containing milled zirconium particulates and ignited by frictional heating or spark ignition of the zirconium arising from defective blender equipment. The hydrogen gas produced by the reaction of molten titanium or zirconium metal and water, possibly from wash-down or the water deluge system, may have also contributed to the explosion. A dust collection system was not installed (refer the practices recommended in NFPA 484 for controlling combustible metal dust hazards).	 Press Blade Damage	Most solid organic materials (and many metals and some nonmetallic inorganic materials) will burn or explode if finely divided and dispersed in sufficient concentrations. Even seemingly small quantities of accumulated dust can cause catastrophic damage. Suspended dust burns rapidly, and confinement enables pressure buildup.

Purchasing Aged Facilities

Before acquiring assets from an owner, due diligence should be undertaken. In particular, examination of all inspection records and the plant availability data, review of the maintenance budget over the past 5 years, the loss record including near miss register and actual losses both in terms of physical damage and business interruption.

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