HSE

Health and Safety Executive

Managing Ageing Plant

A Summary Guide

P Horrocks, D Mansfield, K Parker, J Thomson, T Atkinson & J Worsley
Whittle House
410 The Quadrant
Birchwood Park
Warrington WA3 6FW

The potential degradation of plant and equipment due to age related mechanisms such as corrosion, erosion and fatigue is a key issue for industry. The Health and Safety Executive have recognised asset integrity management and the issue of ageing plant as key topics to address in their inspection programmes.

The Health and Safety Executive has conducted research into these aspects for offshore oil and gas installations and has now conducted work to extend this in the context of hazardous onshore COMAH facilities in particular. As part of this ongoing work, the Health and Safety Executive has been developing internal processes and priorities for these key areas, supported by technical documents to raise awareness and understanding of the issues.

In line with the Health and Safety Executive's role to disseminate information and awareness, these supporting documents are being made available to industry to assist them when addressing ageing plant.

This report, being published to augment the existing RR509[1], provides an overview of ageing plant mechanisms and their management and presents the findings of an analysis of loss of containment events to indicate the extent to which ageing plant mechanisms are a factor.

We hope this document will provide industry with a good understanding of the Health and Safety Executive's views and concerns on this important topic, and provide a useful basis for engagement with industry to ensure the continued safe operation of plant and equipment over many years.

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

HSE Books

FOREWORD

The potential degradation of plant and equipment due to age related mechanisms such as corrosion, erosion and fatigue is a key issue for industry. The Health & Safety Executive have recognised asset integrity management and the issue of ageing plant as key topics to address in their inspection programmes.

The Health & Safety Executive has conducted research into these aspects for offshore oil and gas installations and has now conducted work to extend this in the context of hazardous onshore COMAH facilities in particular. As part of this ongoing work, the Health & Safety Executive has been developing internal processes and priorities for these key areas, supported by technical documents to raise awareness and understanding of the issues.

In line with the Health & Safety Executive's role to disseminate information and awareness, these supporting documents are being made available to industry to assist them when addressing ageing plant.

This report, being published to augment the existing RR509 [1], provides an overview of ageing plant mechanisms and their management and presents the findings of an analysis of loss of containment events to indicate the extent to which ageing plant mechanisms are a factor.

We hope this document will provide industry with a good understanding of the Health & Safety Executive's views and concerns on this important topic, and provide a useful basis for engagement with industry to ensure the continued safe operation of plant and equipment over many years.

Yours,

Health & Safety Executive

Executive Summary

The issue of ageing plant, leading to an increased risk of loss of containment and other failures due to plant and equipment deterioration, has been shown to be an important factor in incidents and accidents.

Recent research shows that 50% of European major hazard 'loss of containment' events arising from technical plant failures were primarily due to ageing plant mechanisms such as erosion, corrosion and fatigue. This data analysis for HSE (Ageing Plant Study Phase 1 report [2]) has shown that across Europe, between 1980 and 2006, there have been 96 major accident potential loss of containment incidents reported in the EU Major Accident Database (MARS) which are estimated to be primarily caused due to ageing plant mechanisms. This represents 30% of all reported 'major accident' loss of containment events in the MARS database, and 50% of the technical integrity and control and instrumentation related events. These 'ageing' events equate to an overall loss of 11 lives, 183 injuries and over 170Million € of economic loss. This demonstrates the significant extent and impact of ageing plant related failures on safety and business performance.

This finding is supported by RIDDOR data which has shown that between 1996 and 2008 it is estimated that there have been 173 loss of containment incidents reported in RIDDOR that can be attributed to ageing plant mechanisms. The short timescales required to send the RIDDOR incident reports to HSE before proper investigation of the root causes can sometimes be completed means that it can be difficult to identify which events may be ageing related: so the actual number could be much higher than that quoted here.

This Technical Resource document has been prepared to assist managers at onshore hazardous COMAH facilities and HSE inspectors in this key topic area.

The guide provides:

- Background information on the topic of ageing plant including a definition of ageing plant, and an analysis of accident data to show its extent and implications
- A summary of the key ageing mechanisms, including their signs and symptoms, the type of plant and process most susceptible to these mechanisms and current good practice for managing these
- Information on where to obtain more detailed information and advice

It is hoped that the guide will also provide a useful resource for industry, both in terms of understanding HSE's approach, understanding the issues and expectations on industry for managing ageing assets, and in raising awareness throughout industry of the effects of ageing plant and how this can be managed effectively.

Contents

Acronyms and Abbreviations

AIMS	Asset Integrity Management System
BA	Breathing Apparatus
CCTV	Closed Circuit Television
COMAH	The Control of Major Accident Hazard Regulations 1999
CP	Cathodic Protection
CRA	Corrosion Resistant Alloy
CUI	Corrosion Under Insulation
DCS	Distributed Control System
E/C&I	Electrical, Control and Instrumentation
ER	Electrical Resistance (Probe)
ESD	Emergency Shutdown System
GRE	Glass Reinforced Epoxy
GRP	Glass Reinforced Plastic
HIC	Hydrogen Induced Cracking
HSE	The Health and Safety Executive
HSEMS	Health, Safety and Environment Management System
HV	High Voltage
HVAC	Heating, Ventilation and Air Conditioning
KPI	Key Performance Indicator
LoC	Loss of Containment
LPR	Linear Polarisation Resistance (Probe)
MARS	European Union Major Hazards Incident Database
MHIDAS	World-wide major hazard incident database
MIT	Maintenance, Inspection and Test
MoC	Management of Change
NDT	Non Destructive Testing
OEM	Original Equipment Manufacturer
PA	Public Address (System)
PLC	Programmable Logic Controller
PPE	Personal Protective Equipment
RBI	Risk Based Inspection
RIDDOR	Reporting of Injuries, Diseases and Dangerous Occurrences Regulations 1995
SCADA	Supervisory Control and Data Acquisition System
SCC	Stress Corrosion Cracking
SCE	Safety Critical Element
SRB	Sulphate Reducing Bacteria
UPS	Uninterruptible Power Supply

1.0 Introduction

1.1 Purpose

The purpose of this guide is to provide targeted information to help HSE inspectors better understand the issues of ageing plant and to promote good practice for managing ageing assets.

It is hoped that the guide will also provide a useful resource for industry, both in terms of understanding HSE's approach, understanding of the issues and expectations on industry for managing ageing assets, and in raising awareness throughout industry of the effects of ageing plant and how this can be managed effectively.

1.2 Scope

This guidance is particularly relevant to the topic of ageing plant in refineries, other hydrocarbon processing plant, chemical process plant and storage facilities, and other similar establishments onshore, and also has relevance to offshore oil and gas installations.

Although this guide is primarily targeted at the process and chemicals sector, many of the ageing issues are also generic to any form of containment or structural feature, or instrumented protective system and so aspects of the guide may also be of use more widely within industry.

1.3 Definition of Ageing Plant

The term 'ageing plant' can be misleading, it is not just related to the age and design life of a plant, system, or piece of equipment. Previous work for the HSE (Research Report 509 on Ageing Plant) [1] defined ageing and ageing plant as:

"Ageing is not about how old your equipment is; it is about its condition, and how that is changing over time. Ageing is the effect whereby a component suffers some form of material deterioration and damage (usually, but not necessarily, associated with time in service) with an increasing likelihood of failure over the lifetime.

Ageing equipment is equipment for which there is evidence or likelihood of significant deterioration and damage taking place since new, or for which there is insufficient information and knowledge available to know the extent to which this possibility exists.

The significance of deterioration and damage relates to the potential effect on the equipment's functionality, availability, reliability and safety. Just because an item of equipment is old does not necessarily mean that it is significantly deteriorating and damaged. All types of equipment can be susceptible to ageing mechanisms."

Overall, ageing plant is plant which is, or may be, no longer considered fully fit for purpose due to deterioration or obsolescence in its integrity or functional performance. 'Ageing' is not directly related to chronological age. There are many examples of very old plant remaining fully fit for purpose, and of recent plant showing evidence of accelerated or early ageing, e.g. due to corrosion, fatigue or erosion failures.

1.4 Ageing Asset Types

It is important to recognise that many systems and features which may be subject to ageing, can contribute to the health, safety and environmental performance of plant, or could compromise the performance were they to fail or collapse. A broad view is therefore required when assessing the potential impact of ageing at a given installation.

The various asset types can be segregated into four basic categories:

- Primary containment systems
- Control & Mitigation Measures, i.e. Safeguards
- EC&I systems
- Structures

EC&I systems can be considered as a type of safeguard. However, given the different nature and relative importance of the functions performed by this type of equipment, it is considered desirable to highlight this category specifically.

Table 1 sets out the types of physical assets or features that may be subject to ageing.

Table 1: Physical Assets Considered Relevant to Ageing

Asset Type	Examples
Primary Containment Systems (Process and Utilities)	Static Elements – vessels, pipework and fittings, whether at significant pressure or not, e.g. pressure vessels, columns, heat exchangers, storage tanks, open top tanks, pipework, and pipework fittings such as valves, strainers, flanges, ejectors, etc
	Rotating / Motive Elements, e.g. pumps, compressors, turbines, agitators, fans, solids handling equipment, etc
Control & Mitigation Measures	Process Safeguard Systems, e.g. • Mechanical pressure protective systems - pressure/ vacuum relief valves, bursting discs, vents and flares • Mechanical overfilling protective systems - overflows, emergency dump systems • Ignition source control equipment, eg earthing, equipment enclosures, etc • Inerting systems (e.g. nitrogen blanketing and purging) • Trace heating, cooling or other thermal insulation systems for process insulation or operator protection
	Secondary or Tertiary Containment Systems, e.g. • Double skin vessels and pipes • Bunds • Paved areas, kerbing, gulleys, sumps, etc • Under soil/ underground non-permeable membranes and land drains • Drainage systems • Effluent treatment systems, interceptors, penstock valves for

Asset Type	Examples
	outfall isolation, etc • Emergency holding tanks and lagoons, etc
Control & Mitigation Measures (continued)	Control and Mitigation Systems, e.g. • Action fire protection and firewater systems, including fusible loops or plugs, fire pumps, fire water lagoons or storage tanks, ring mains, hydrants, monitors, spray and deluge systems, etc • Passive fire protection systems • Blast protection, relief and suppression systems • Inert gas fire suppression systems (e.g. CO_2) • Impact protection systems e.g. crash barriers, dropped object protection, shielding • Gas knockdown or inerting systems • HVAC systems to prevent smoke or gas ingress or protect people or key safety critical equipment • Communication systems - telephones, radios, PA systems • Emergency lighting • Spill kits, and environmental spill / release clean up or control equipment and systems • Portable flammable gas and toxic gas monitors etc • PPE for use in an emergency - BA sets, gloves, chemical suits, face masks, etc • Rescue equipment • Emergency showers and eye wash stations • Portable fire extinguishers and manual fire fighting equipment
	External Hazard/ Environmental Safeguards, e.g. • Flood protection arrangements • Lightning protection • Trees or other natural features/ ecosystems that could impact plant/pipelines if they collapsed or caused root damage or burrowing, or block outfalls or overflows • Areas prone to subsidence, rock fall or land slip, etc
EC&I Systems	EC&I - safety critical process safeguarding systems (trips, alarms, process ESD, etc)
	EC&I - safety critical leak detection and response systems (fire and gas leak / area detection, emergency shutdown systems)
	Integrity and availability of key services such as power supply, UPS, emergency back up generators, battery units, etc
	CCTV Monitoring of plant areas and escape routes, etc
Structures	Supporting structures, civils features and foundations for: • Primary containment • Secondary and tertiary containment, including bunds, kerbs, drains, effluent and storm/ fire-water lagoons and basins • Providing impact protection, e.g. protection from vehicle collision, blast, lifting operations, gas cylinders, etc • Safe places of work, e.g. controls rooms, offices, workshops, emergency shelters • Access and escape routes, e.g. roadways, ladders, stairs, gantries, walkways, etc • Safety critical services and utilities, e.g. power distribution, equipment and battery rooms, etc

Asset Type	Examples
	Safety critical EC&I equipment, weatherproofing, ingress protection, etc Structures and civils features that could impact major hazard plant, pipelines or equipment (including EC&I and safeguarding equipment, cabling, etc) were they to collapse / fail, or which could disperse spilt material if they were to leak/ fail, e.g. flood defences, chimneys, communication towers, canal or reservoir embankment, sea defences, buildings, walls, flares/ stacks, tall lighting towers, earth embankments, retaining walls, culverts, bridges, tunnels, underground caverns, etc.

1.5 Prevalence and Impact of Ageing on Major Hazard Plant

Onshore chemical plant in the UK is ageing. Health and Safety Executive (HSE) field inspectors often have to consider the Operators' safety justification for continued use of ageing plant taking account of a variety of issues such as usage, design life, known research, known operational and failure history, maintenance and inspection history, etc. The issues also need to be considered against a background of increasing competition from overseas, and the pressure on resources and investment which this has had over recent years, with reductions in manning levels, retirement of experienced staff, and pressure on operating budgets.

From a health, safety and environmental perspective, there is a need to be able to identify those sites and installations where ageing may present a significant increase in risk. This will depend on several factors, including:

- The inherent hazards and risks of the installation
- The propensity of the installation to ageing related deterioration or damage
- The likely types of ageing mechanisms and where and how these could present themselves
- The extent to which ageing is being effectively managed

Recent research undertaken for HSE [2] addressed this by conducting a detailed review of available incident data to firstly ascertain if ageing is a significant issue and secondly to identify key factors or issues driving this.

The key databases interrogated were RIDDOR, including the chemical and process industry voluntary incident reporting schemes, MARS (EU Seveso II major hazard Incidents) and MHIDAS (Worldwide major hazard accidents).

The study found that, in terms of major accidental potential events at major hazard installations, the MARS data provides the most appropriate basis to assess the significance of ageing as these events should be directly applicable to UK COMAH installations or other chemical plant when considering major leaks and incidents. The study determined that the MARS data indicates that approximately **60% of major hazard loss of containment incidents are related to technical integrity and, of those, 50% have ageing as a contributory factor**. It therefore concluded that plant ageing mechanisms are a significant issue in terms of major hazard accidents.

The importance of ageing mechanisms is supported by RIDDOR data which has shown that between 1996 and 2008 it is estimated that there have been 173 loss of containment incidents reported in RIDDOR that can be attributed to ageing plant mechanisms. The short timescales required to send the RIDDOR incident reports to HSE before proper investigation of the root causes can sometimes be completed means that it can be difficult to identify which events may be ageing related: so the actual number could be much higher than that quoted here. The limited details from the MHIDAS database also made it difficult to positively identify the role of ageing mechanisms, though it is considered likely that these mechanisms were involved in many incidents.

A significant observation from the data review was that positive identification of incident causes, especially related to plant ageing, can be difficult from the text descriptions provided in many accident databases. There is significant variation in the degree of detail provided in the reports which limits the usefulness of the data in this kind of analysis. Experience from the review suggests that a useful development in RIDDOR reporting of incidents would be to include a simple checklist focused on causation, i.e. recording of contributing factors that emerge from the incident investigation.

Details of the analysis that led to the above observations can be found in the Phase 1 Report for this study [2].

2.0 Ageing Mechanisms and their Management

2.1 Ageing Mechanisms and What they can Affect

This section of the guide provides a brief introduction to the mechanisms that can lead to age related deterioration of plant, processes and equipment. It is intended to provide concise and focussed information for non-specialists who are involved with the management of ageing plant and HSE Regulatory Inspectors who may inspect ageing plant at onshore COMAH facilities to help them understand the key issues and know what key indicators to look for.

In cases where an inspection raises potential issues that require more specialist assessment or advice, then the relevant topic specialist expertise should be consulted.

The resources listed in Section 5.0 can be accessed if more a detailed understanding of the mechanisms is desired.

Various generic ageing mechanisms can be present depending on the circumstances. These can affect a variety of asset types. A summary of the ageing mechanisms and the asset types they can affect is presented in Table 2.

Table 2: Ageing Mechanisms Affecting Physical Assets

Ageing Mechanism	**Primary Containment**	**Structures**	**Safeguards**	**EC&I**
Corrosion	✓	✓	✓	✓
Stress Corrosion Cracking	✓	✓	✓	
Erosion	✓	✓	✓	✓
Fatigue	✓	✓	✓	
Embrittlement	✓	✓		✓
Physical damage	✓	✓	✓	✓
Spalling		✓		
Weathering		✓	✓	
Expansion/ contraction due to temperature changes (process or ambient) or freezing	✓	✓	✓	✓
Instrument drift				✓
Dry joint development				✓
Detector poisoning				✓
Subsidence		✓	✓	

In terms of primary containment a general list of damage types and mechanisms for pressurised equipment can be found in HSE RR509 [1].

Ageing degradation would be expected to be more prevalent where there is some degree of incompatibility between the process fluids and the materials of construction of the equipment. Table 3 provides an indicative guide to identifying which equipment on a plant may be more likely to be affected by ageing degradation, mainly drawing on material compatibility data.

Table 3: Indicative Guide to Ageing Plant Degradation

Material Type

Process Fluid	Carbon Steel	Stainless Steel 13 Cr	Stainless Steel Type 304	Stainless Steel Type 316	Duplex Stainless Steel (22% Cr)	Super Duplex Stainless Steel (25% Cr)	Hastelloy 625	Monel	Aluminium	GRE/GRP	Copper	Titanium	Elastomers
Cooling Water	Medium	Medium	Low	Low	Low	Low	Low	Low	Medium	Low	Low	Low	Medium
Process Water	High	High	Medium	Medium	Low	Low	Low	Low	Medium	Low	Medium	Low	Low
Deaerated Water	Medium	Low	Low	Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low
Sea Water	High	High	High	High	Medium	Low	Low	Medium	Medium	Low	Medium	Low	Low
Strong Acid	High	High	High	High	Medium	Medium	Low	High	High	Medium	High	High	Medium
Weak Acid	High	High	High	High	Low	Low	Low	High	High	Low	High	Medium	Low
Strong Alkali	Medium	Medium	Medium	Medium	Medium	Low	Low	Medium	High	Medium	High	Low	Medium
Weak Alkali	Medium	Medium	Medium	Medium	Low	Low	Low	Medium	High	Low	High	Low	Low
Aromatic Hydrocarbons	Low	Low	Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low	High
Aliphatic Hydrocarbons	Low	Low	Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low	High
Acid Gas	High	High	High	Medium	Medium	Medium	Low	Medium	High	Low	High	Low	Low
Dry Air	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low	Low
Wet Air	High	Medium	Medium	Low	Low	Low	Low	Low	Medium	Low	Low	Low	Low
Hydrogen	Medium	Medium	Medium	Medium	Low	Low	Low	Low	Medium	Medium	Medium	Low	Low
Dry Alcohols	Low	Low	Low	Low	Low	Low	Low	Low	Low	Medium	Low	Low	Medium
Organic Amines	Medium	Medium	Medium	Low	Low	Low	Low	Medium	Medium	Low	Medium	Low	Medium
Chlorine Gas	High	High	High	High	High	Medium	Low	Medium	High	Low	High	Medium	Medium
Steam	High	Medium	Medium	Medium	Medium	Medium	Medium	Medium	High	High	High	Low	High

Key:

High Likelihood of Ageing Degradation (red)
Medium Likelihood of Ageing Degradation (orange)
Low Likelihood of Ageing Degradation (green)

Note: Table 3 is a general guide to aid inspection teams in locating ageing plant equipment. There are, however, many variables such as temperature, pressure, concentration, flow velocity and aeration which affect plant ageing and could therefore change the ratings given. Temperature in particular plays a very significant role in materials performance for any given environment and this table does not take account of any extremes of temperature which may cause significant degradation to materials which are represented here by the low rated boxes.

The ageing mechanisms, where they might occur, and how to recognise and manage them is discussed below.

2.2 Corrosion

Corrosion may be defined as the physical degradation of a material due to chemical reactions taking place on its surface when it is exposed to an environment which will support those reactions.

Wet (Aqueous) Corrosion

Wet corrosion is the most commonly encountered form, it takes place on a susceptible metal surface if water is present in the environment, this also includes water present as vapour in the atmosphere. In the absence of water, wet corrosion will not occur. This is due to the electrochemical nature of the wet corrosion reaction mechanism:

Dry (Hot) Corrosion

Unlike wet corrosion, dry corrosion takes place in the absence of water. It typically occurs at temperatures in excess of 400^{o}C where there is direct chemical oxidation of the surface metal to its metal oxide in the presence of Oxygen.

$$M(s) + O_2 > MO_2$$

2.2.1 Mechanisms

General Corrosion

General corrosion is defined as corrosion which causes a uniform loss of wall thickness which is observed over the entire surface area of the metal exposed to the same conditions. Wall thickness measurements and corrosion rates measured from weight loss coupons, Linear Polarisation Resistance (LPR) or Electrical Resistance (ER) probes can be used to monitor the extent of the internal damage caused by general corrosion. Inspection techniques used to detect this type of damage are discussed in HSE RR509.

Externally, general corrosion is easily identified at exposed structures by the distinctive orange coloured iron oxide corrosion product deposits seen on the surface of uncoated carbon steels. General corrosion is the most common damage mechanism observed in carbon and low alloy steels. Corrosion resistant alloys, however, are typically resistant to this form of corrosion under most conditions.

Localised Corrosion

Localised corrosion is a specific form of corrosion which occurs only at a relatively small area of the total metal surface. Localised corrosion can be extremely damaging to a structure due to rapid degradation and because of the local nature of the attack, the damage can easily pass undetected until a failure occurs. Typically localised corrosion mechanisms are the main form of attack observed for corrosion resistant alloys. However it can also occur with carbon and low alloy steels under certain conditions.

Inspection techniques used to detect this type of damage are discussed in HSE RR509.

Common forms of localised corrosion are:

Pitting corrosion
Pitting is an extremely localised form of attack where the wall loss is confined to a very small area of the surface. The conditions within the pit can quickly become increasingly aggressive causing corrosion pits to rapidly advance through the wall thickness whilst the vast majority of the pipe or vessel wall remains unaffected. This can lead to very rapid failures as the pit quickly penetrates the wall. This form of attack is one of the main forms of corrosion observed in corrosion resistant alloys, however it is also found with corrosion of carbon steels.

Crevice corrosion
Crevice corrosion is similar to pitting corrosion, in that it is likely to be observed under the same environmental conditions that have given rise to pitting. In crevice corrosion the area of localised attack is found within crevices which typically form around and under washers, bolts and seals. The solution within the trapped pocket can become increasingly aggressive and significant localised attack can occur around the crevice.

Galvanic corrosion
Galvanic corrosion occurs at the junction of two dissimilar metals which are in electrical contact with each other. According to their relative positions within the galvanic series one metal will be protected from corrosion at the expense of the other. Depending on the relative surface areas of each metal this form of corrosion can proceed extremely quickly. If the cathodic metal is much larger than the anodic metal surface then the observed corrosion rates can be extremely high as a large cathodic area is driving corrosion at a relatively small anodic point.

Figure 1: Example of galvanic corrosion (in this case dissimilar weld corrosion in heat affected zone)

<u>Velocity related corrosion attack</u>

Erosion Corrosion
Erosion corrosion is a faster form of corrosion attack than would otherwise be expected in a given environment due to high flow conditions or localised turbulence. The increased corrosion damage is caused by the high shear stresses stripping away protective corrosion product films and increasing the transport of the corrodent in the system to the metal surface. The effect is increased if solid particles such as sand are present in the system. This form of corrosion is often observed in copper structures but can affect any material susceptible to corrosion.

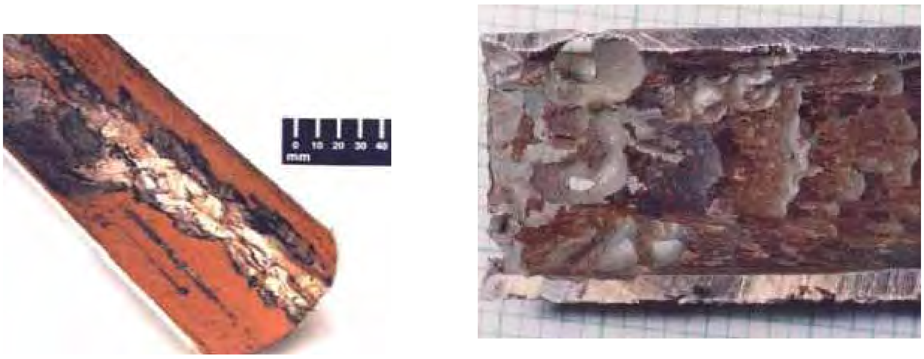

Figure 2: Examples of Erosion Corrosion

Mechanical Damage

Cavitational Corrosion

Cavitational corrosion is a form of mechanical damage which also damages protective films formed on metal surfaces. Cavitation bubbles can form in liquids at areas of a sudden drop in pressure, these bubbles become unstable and can quickly collapse. The pressures and temperatures formed inside a cavitation bubble as it collapses can be extremely high. When a cavitation bubble forms and subsequently collapses on a metal surface this energy is directed onto the surface of the metal which can cause significant metallurgical damage to occur.

Areas where cavitation is likely:

- At the suction end of a pump.
- At the discharge of a valve or regulator, especially when operating in a near-closed (choked) position
- At other geometry-affected flow areas such as pipe elbows and expansions
- Also, by processes incurring sudden expansion, which can lead to dramatic pressure drops

Specific Types of Common Corrosion

Carbon Dioxide (Sweet) Corrosion

Carbon dioxide dissolves in water to form carbonic acid which causes what is known as sweet corrosion. The product of this form of corrosion is iron carbonate which forms as a film on the metal surface. At higher temperatures (+80^{o}C) this film has protective qualities leading to lower than expected corrosion rates at higher temperatures. Sweet corrosion is typically observed as metal wall thinning and shallow pitting. Under high velocity conditions deep elongated pits are sometimes observed.

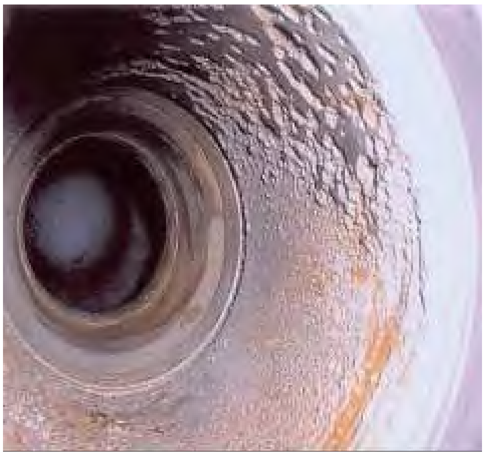

Figure 3: Example of CO_2 Corrosion

Hydrogen Sulphide (Sour) Corrosion

Hydrogen Sulphide dissolves in water to cause what is known as sour corrosion. The product of this form of corrosion is iron sulphide. The low solubility of iron sulphide in water results in the formation of a dark or black corrosion product film that is able to protect the steel surface from general corrosion even in aggressive systems. However due to the conductive nature of the protective film any local break in the iron sulphide layer can result in very severe pitting.

Hydrogen sulphide may also cause hydrogen damage in susceptible steels. The reaction which gives rise to the iron sulphide film releases atomic hydrogen which can then diffuse into the steel where it can lead to the formation of hydrogen blisters or through wall cracking (Sulphide Stress Corrosion Cracking or Stress Oriented Hydrogen Induced Cracking).

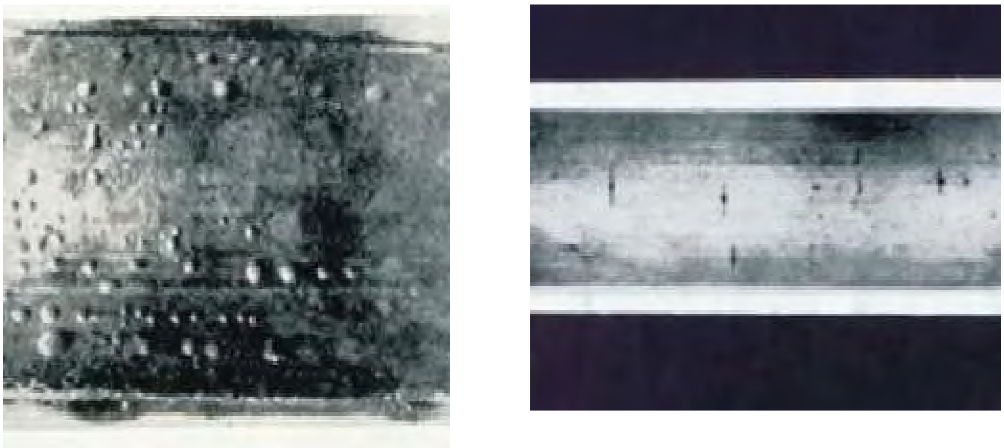

Figure 4: Examples of Sour Corrosion and Cracking

Microbial Corrosion

Microbial corrosion is caused by the action of bacteria contaminated systems, commonly sulphate reducing bacteria (SRB's). It is not the bacteria themselves that attack the metal but the local environments that they create and contribute to that leads to corrosion of the structure. Microbial corrosion is typically a problem inside pipes which are left with stagnant water, at dead legs and in the bottom of tanks. For microbial corrosion to occur conditions must be suitable to support bacterial life. These requirements include:

- Presence of bacterial life in the system.
- Source of Sulphate.
- Source of Carbon.
- Source of water.
- Anaerobic conditions.
- Close to Neutral pH.
- Suitable temperature and pressure for bacterial life to be sustained.

Figure 5: Examples of Bacterial Degradation

Atmospheric Corrosion

Moisture, oxygen and aggressive species such as sulphate, nitrates and chlorides present in the atmosphere can lead to atmospheric corrosion occurring on exposed structures. Atmospheric corrosion proceeds under the same mechanism as wet corrosion however as a bulk liquid phase is only present during rainfall the corrosion reactions proceed in a thin film of condensed or absorbed moisture on the metal surface.

The major factors that affect the rate of atmospheric corrosion at a given location are the moisture levels and the concentrations of aggressive species in the environment. Marine environments for example with high levels of chlorides present would exhibit significantly greater corrosion rates than inland environments with low levels of chloride. Similarly exposed metal structures in industrial locations with high levels of pollution and therefore higher levels of sulphates and nitrates than rural locations would record higher atmospheric corrosion rates than would be observed in rural locations.

Figure 6: Examples of Atmospheric Corrosion

More examples of corrosion mechanisms and identification of the main mitigation methods for them can be found in the Energy Institute document “Guidance for Corrosion Management in Oil and Gas Production and Processing” ([3], Page 78).

2.2.2 Signs and Symptoms

Corrosion is perhaps one of the more obvious signs of plant ageing because of visible signs of corrosion product, either external or internally within equipment. The nature of many materials, especially carbon and low alloy steels, is to react with the environment by a corrosion process to attain a more stable condition, e.g. metallic iron “wants” to become iron ore again. Many equipment items take account of this in the design process e.g. corrosion allowance so it is important to note that the presence of corrosion products, i.e. rust, does not indicate that equipment is not fit for its service. Rust is merely a sign that the equipment is ageing. The rate of this ageing process and its importance in risk terms are parameters the plant operator should be concerned with.

2.2.3 Susceptibility

All metallic materials are susceptible to corrosion and/or corrosion cracking. Materials termed “corrosion resistant alloys” or CRAs are less susceptible but not immune. This class of materials are protected by a corrosion process that forms a thin layer of metal oxide at the surface. Should the layer be damaged in an environment that does not support re-oxidation, then the material can become susceptible to corrosive attack.

2.2.4 Management Options

Corrosion can be prevented or monitored and controlled. Prevention methods include coatings and/or cathodic protection (often termed “CP”). CP can be achieved either by the use of impressed currents or by connection of sacrificial anodes typically made from zinc or aluminium blocks. If coatings are used there should be evidence of coatings inspection and if CP is employed evidence of maintenance and monitoring of CP effectiveness should be available.

For monitoring and control, management of corrosion is achieved through the following processes:

- Identification
- Detection
- Quantification
- Assessment

Identification usually involves a risk assessment, e.g. RBI plan or may take the form of asset registers arranged to identify those equipment items that are expected to corrode in one way or another.

Detection is the application of a suitable inspection technique, often visual, that can locate the corrosion.

Quantification is achieved by measuring the remaining thickness of material available to contribute to the overall structural integrity of the equipment. In some instances, engineering judgement is applied but this should be documented to a sufficient extent that reasonable next inspection intervals can be deduced.

Whenever corrosion is detected an assessment ([1], Page 74) should be made of its implications for equipment integrity. This assessment should inform any actions that are to be taken in the future including inspections and any repairs/modifications that may be made.

2.3 Stress Corrosion Cracking

2.3.1 Mechanisms

Chloride Stress Corrosion Cracking
Stress Corrosion Cracking (SCC) is observed at susceptible austenitic stainless steels in certain environments. SCC typically occurs in chloride containing environments, for SCC to occur the material must be stressed. The stress does not only need to take the form of an applied physical load to the structure, residual stresses around welds and bends as well as temperature gradients can create stresses that will initiate SCC in a susceptible environment. If either a suitably aggressive environment or a stress is not present then no crack will initiate in the steel, both are required to cause SCC ([3], Page141).

Hydrogen Induced Cracking (HIC)
Often found in sour environments. The presence of H_2S hinders the formation of H_2 gas from the hydrogen atoms produced by the corrosion reaction. Instead the hydrogen atoms are able to enter the steel structure. Hydrogen atoms collect at small voids and inclusions within the steel where they combine to form H_2 gas. The gas pressure of H_2 at these pockets builds up as more hydrogen atoms combine and can become extremely large, leading to cracks forming within the steel structure ([3], Page 82).

Corrosion Fatigue
Corrosion fatigue is the enhancement of the rate of crack growth in a corrosive environment above that which would be expected in a purely mechanical fatigue dry environment. Sources of fatigue include vibration and also the expansion and contraction associated with thermal cycling of equipment.

2.3.2 Signs and Symptoms

SCC is notoriously difficult to detect without the aid of NDT. However, there are tell-tale signs that indicate that SCC might be present in certain cases. For instance, it is well known that pitting corrosion at welds in corrosion resistance alloys is often (though not always) a precursor to SCC since cracks often begin at the bottom of pits. Additionally and in the same alloy group, the surface may exhibit rusty staining with little or no apparent source. This staining is corrosion product originating from within a tight stress corrosion crack.

Figure 7: Examples of Stress Corrosion Cracking

SCC has two distinct phases of development, (i) initiation and (ii) growth. There are no reliable models to predict the time to initiation of a crack and subsequent growth rates are generally unknown and unpredictable. Propagation can be potentially very fast, leaving very little time to act on any observation of the likely presence of a crack.

In most cases, signs of SCC will only be detected as a result of planned plant inspections where the susceptibility to SCC has been identified as part of the planning process, e.g. using risk based inspection. Advice on suitable detection methods can be found in HSE RR509 on Ageing Plant ([1], Page 71).

2.3.3 Susceptibility

The table below presents a list of common alloy/environment systems where SCC may occur [4]. Cracking susceptibility is dependent upon temperature, environment composition, tensile stress level and heat treatment of the specific alloy.

Table 4: Susceptibility Guide to Stress Corrosion Cracking

Alloy	**Environment**
Aluminium alloys	Chloride solutions
Magnesium alloys	Chloride solutions
Copper alloys	Ammonia + oxygen + water Amines + oxygen + water Nitric acid vapour Steam
Carbon and low alloy steels	Nitrate solutions Caustic solutions Carbonate solutions Alkanolamines + carbon dioxide Carbon monoxide — carbon dioxide + water Anhydrous ammonia + air Hydrogen cyanide solutions
Austenitic stainless steels and some ferritic and duplex stainless steels	Chloride and bromide solutions Organic chlorides and bromides + water Caustic solutions H2S solutions — chlorides or oxidants
Nickel Alloys	Caustic solutions Fused caustic Hydrofluoric acid H2S solutions — chlorides or oxidants
Titanium Alloys	Aqueous salt systems Methanol plus halides Nitrogen tetroxide
Zirconium Alloys	Aqueous salt systems Nitric acid
Sensitised austenitic stainless steels	Water — oxygen (high temperature) Chloride solutions Polythionic acid solutions Sulfurous acid

2.3.4 Management Options

SCC requires the combination of a susceptible material, a tensile stress and an aggressive environment. SCC should be prevented at the design stage by the appropriate selection of materials and control of the stress levels. The unpredictable nature of SCC renders it extremely difficult to monitor and control. If SCC is found it should be repaired or measures taken to fully mitigate the potential consequences of any failure.

2.4 Erosion

2.4.1 Mechanisms

Erosion is the removal of the surface of a material by abrasion. Hard particles impact the surface causing surface wear resulting in loss of material. Erosion is fundamentally different to corrosion because it is not an electrochemical process. It depends mainly on the difference in hardess between the material and the impacting particles and the velocity and impact angle.

Erosion if often found in systems where solids are transported, e.g. systems containing sand, solid products or slurrys. Additionally, erosion can be caused by the impact of liquid particles, e.g. in condensing steam systems ([3], Page 146).

2.4.2 Signs and Symptoms

Prior to failure the most important sign of erosion is the loss of material thickness at certain points in a system or structure.

Figure 8: Erosion of a Pipe Bend

2.4.3 Susceptibility

All materials are susceptible to erosion when impacted by harder particles. Particular susceptibility occurs at positions where there are changes in flow direction and/or velocity, for example at piping bends or choke valves.

2.4.4 Management Options

Management options for erosion are the same as for corrosion. Erosion can be prevented or monitored and controlled in the same way as corrosion and the same assessment methods apply.

2.5 Other mechanisms

A comprehensive list of common damage mechanisms that affect chemical processing equipment can be found in API 571 [5]. Many are common to those found in offshore processing as described in Energy Institute Document "Guidance for Corrosion Management in Oil and Gas Production and Processing" ([3], Page 1).

2.6 Some Key Specific Issues

2.6.1 Corrosion Under Insulation (CUI)

The presence of external insulation coverings on pipelines and vessels can lead to corrosion which is much more severe than would be expected if the equipment was uncoated. There are several reasons for this to happen:

- The insulation creates a creviced area at the surface of the metal which can retain water.
- The insulation itself may absorb or wick water.
- The insulation material may contain contaminates which increase the corrosion rate.
- The insulation hides from view almost all visual evidence of corrosion occurring underneath.

There are two main sources of water under insulation:

- Condensation.
- External sources such as rain, cooling tower discharge, condensate dripping from cold equipment above, steam discharge, process liquid spillage, etc.

Entry of water can be prevented by adequate weatherproofing of the insulation materials. However it is not possible to completely prevent the ingress of water vapour from the atmosphere and therefore condensation can form on the metal surface underneath the insulation. Additionally damaged and/or inadequate weatherproofing can lead to water penetration.

Forms of Corrosion found under Insulation

Moisture trapped under insulation would be expected to cause general corrosion of carbon steels at areas of uncoated pipework. The level of general corrosion observed would depend upon the existence, quality and condition of the coating system applied to the steel below the insulation. At stainless steels localised corrosion would be expected particularly if chloride contamination is present under the insulation which may lead to localised corrosion in the form of pitting and crevice corrosion. Additionally, cracking in the form of stress corrosion cracking or corrosion fatigue may be observed in susceptible areas.

Figure 9: Examples of Corrosion Under Insulation

Inspection of insulated equipment

Inspection is difficult as the metal surface is covered by insulation. Complete removal of the insulation would be needed to allow for a thorough visual inspection of the metal surfaces for CUI, however this is usually impractical. Visual inspections should begin by identifying areas where damage and breaks to the weatherproofing potentially allowing water ingress are visible. Additionally swollen or misshapen insulation can indicate the presence of rust built up below the insulation.

If no areas of damaged weatherproofing are visible then inspections should concentrate on the following areas:

- Surfaces exposed to frequent hot to cold cycles.
- Cold temperature equipment with parts which project through the insulation.
- Interfaces between hot and cold equipment.
- Horizontal pipe work, especially where there are joints and branches extending from the base.

Inspection Techniques

The standard inspection technique is to remove small sections of the insulation at regular intervals across the pipework to allow inspection of the condition of the metal surface below. Appropriate techniques for inspection of pipework, once a small spot of insulation has been removed, include:

- Visual inspection of the surface for evidence of dampness, coating defects and surface rusting.
- Ultrasonic wall thickness measurements can be taken to asses the level of wall loss due to general corrosion.
- For Stainless Steels where no general corrosion would be expected a visual inspection for evidence of localised areas of rust staining indicating the presence of

pits or crevice corrosion can be conducted and a technique such as Dye Penetrant used to identify SCC cracks in the structure.

Inspection of pipework by spot removal of insulation poses two problems. Firstly the removal of some insulation sections creates a break in the weather proofing and a potential entry point for water ingress in the future. Once the inspection is complete the insulation must be carefully replaced and sealed to prevent water entering at the inspection points. Secondly only a small percentage of the structure can be inspected this way which has the potential to miss defect areas. Therefore there are some inspection techniques that allow the entire structure to be inspected with either minimal removal or no removal of the insulation required. A selection of these techniques are summarised below:

Flash Radiography can be used to carry out preventive checks on insulated pipelines, vessels and equipment with diameters up to one meter. An image is produced on medical film which is used to measure any wall thickness loss due to CUI.

Guided Wave Ultrasonic measurements can be used to inspect for both internal corrosion and corrosion under insulation. A small portion of the insulation needs to be removed to attach the probe ring to the structure. The ring transmits ultrasonic waves through the structure. The echo of these waves is then used to assess the wall thickness. The waves are able to travel across straight sections, bends supports, welds and even buried or otherwise inaccessible sections.

Profile Radiography: Exposures are made to a small section of the pipe wall from above the insulation. This technique is able to measure wall thicknesses of pipelines up to 10 inches in diameter over relatively small areas of the surface. Measuring larger pipeline diameters is possible but it can be very technically challenging. Additionally the radiation source can pose safety problems to the operator.

The following techniques are applicable to assessing general corrosion only;

- Pulsed Eddy Current
- Digital Radiography
- Infrared Thermography
- Neutron Backscatter

Inspection Techniques for Pitting
External pits can be identified visually by tell tale rust stains surrounding the pitting.

Internal pits can be visually inspected in the case of large vessels where entry is practical..

Pit Monitoring:
Electrochemical noise measurements can be used to monitor pitting formation in real time. Additionally, pitting examinations of weight loss coupons can give an indication if pitting is taking place on the internal surfaces of the structure.

2.6.2 Machines & Rotating Equipment

Loss of containment from age related deterioration of machinery and/or rotating equipment can occur in the same way as for static equipment. The range of mechanisms that can cause such integrity failures are essentially the same as those for static equipment but the dynamic nature of machines can exacerbate the rate of deterioration in some instances. Some examples from HSE RR509 include:

- Build up of solids on a fan impeller can cause fatigue failure and ejection of parts.
- Corrosion or fouling of turbine over-speed protection devices.
- Valve seizure (particularly important for pressure relief valves).
- Fouling of an oil cooler which causes lubrication failure that in turn causes bearing failure, resulting in shaft failure and ultimately, breach of containment.
- Blockage of heat exchanger tubing/pipes.
- Corrosion or fouling of pumps or fan impellers can reduce throughput and adversely affect the performance of associated equipment, e.g. a cooling system.
- Vibration of rotating equipment due to out of balance.

The types of machinery and equipment used in the chemical industry are very similar to those utilised offshore. HSE Research Report 076 on “Machinery and Rotating Equipment Integrity Inspection Guidance Notes” [6] provides a comprehensive description of many of the equipment types in common use and identifies many of the issues, including ageing issues that can affect the equipment.

2.6.3 Fired Heating Equipment

Fired heating equipment is subject to ageing both on the fire-side and the process side. Normal ageing processes discussed above apply, e.g. corrosion, stress corrosion cracking etc, but are added to with specific ageing mechanisms related to the high temperatures on the fire-side, e.g. high temperature oxidation and creep. In addition, significant thermal cycling can give rise to fatigue over a period of time and metallurgical changes can occur because of prolonged service at high temperatures.

More detail on potential damage mechanisms and methods of inspection that should be used can be found in API Recommended Practice 573 on “Inspection of Fired Boilers and Heaters” [7].

2.6.4 Non-Metallic Materials

Composites do not corrode per se but can be subject to a number of degradation mechanisms in-service including physical ageing, mechanical ageing and chemical ageing. The consequence of these can be a reduction of 20 - 40% or greater in the strength characteristics of the polymer during the lifetime of the component and introduction of damage including matrix cracking and delaminations. This is handled in design codes by use of regression curves based on short term and longer term (typically 1000h) tests to determine the *qualification pressure* for the component and the allowed *operating pressure* over the design life.

There is concern about whether such methods of life assessment are sufficiently robust, given the increasing diversity of applications in which composites are applied. In contrast to steel vessels or pipework where non-destructive methods such as ultrasonics, electromagnetics and radiography are widely applied, very little inspection other than visual inspection or pressure testing is currently undertaken on composite components in the chemical, process and petrochemical industries.

There are limitations in the testing methods used to estimate the regression curve or degradation that may occur with ageing in service. Most studies are in water rather than organic solvents or the other fluids that are seen in service. Immersion testing rather than single-sided exposure mechanisms may cause mass gain as well as loss; so single-point data is of limited use in prediction of longer term degradation. Service components suffer environmental degradation from the surfaces; hence the degradation seen in immersion tests may be worse than seen in practice.

A diversity of environments can be encountered in the chemical and process industries. These can cause damage to both the matrix and the fibres. It is important that the resin and fibre types are correctly selected for the application to maximize the resistance in service. In oil industry applications a corrosion resistant layer (or veil) containing more resistant fibres and gelcoat is commonly applied to the surface. Similar practice may be used in chemical applications. Such layers are effective at preventing environmental damage but are relatively thin (~200um). It is important to confirm on visual inspections that excessive grazing of the gel coat has not occurred and that damage has not occurred to these protective layers

Areas of bend, variations in thickness, support or change in geometry are particularly susceptible to damage or degradation in composite systems. These may encounter local stress concentrations and care is needed in design to ensure these can adequately support the operating pressures of the piping or vessel and that the allowance made in regression curves for ageing is sufficient.

There are particular issues for lined or painted glass fibre reinforced epoxy (GRE) vessels or pipework. If a lining is used then a compromise may be made on the resin and fibres used in the GRE vessel. These may not be as resistant as would be used if the GRE was exposed to the environment. It is important in this case to monitor the lining condition since lining failure could lead to degradation and failure of the GRE vessel in a shorter timescale than might typically occur for an unlined vessel exposed to the same environment. Composite components are often painted for cosmetic reasons. This may provide some additional protection to the external environment. A consequence of painting is that it is no longer possible to inspect the component visually using internal illumination, a standard method. In this case detection and monitoring of service damage may be more difficult.

A more detailed description of the types of failure mode observed in non-metallic materials in containment service is provided in Appendix 2 of the Phase 1 Report [2].

2.6.5 Concrete Support Structures

Concrete, especially reinforced concrete, is as susceptible to ageing effects as any other material. Some common causes of defects are illustrated in Figure 10 below [8].

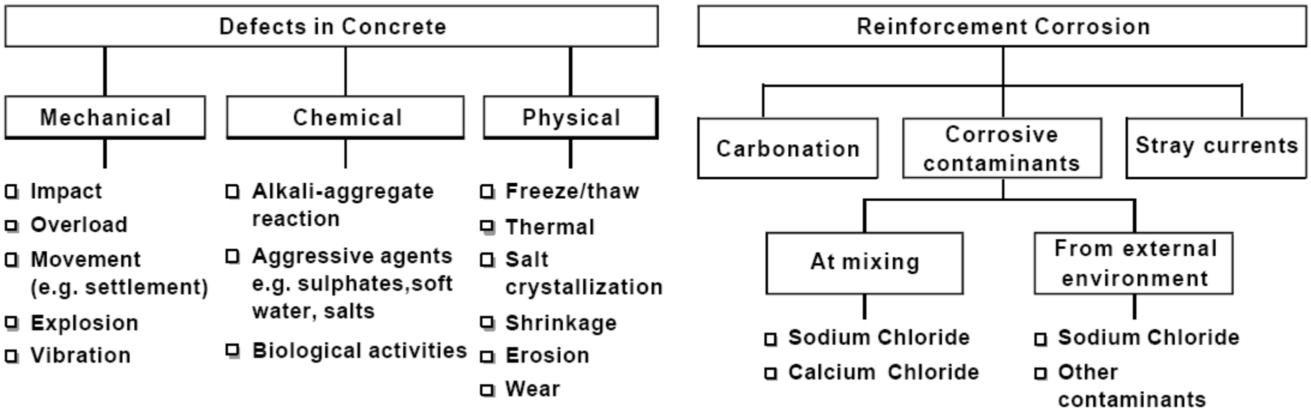

Figure 10: Common Causes of Defects in Concrete Structures

Monitoring and assessment of such defects is covered by EN 1504 [9]. Where such structures are employed in safety critical service, e.g. support of pressure containing vessels etc, evidence of monitoring and assessment of age related degradation should be available.

In cases where cathodic protection (CP) is applied to protect the steel reinforcement within a concrete structure evidence of periodic monitoring of CP effectiveness should be apparent. For more details on CP of steel in concrete please refer to BS EN 12696 [10].

2.6.6 Glass Reinforced Plastic (GRP)/Glass Reinforced Epoxy (GRE) Tanks

Glass-reinforced Plastic/Epoxy is a composite material which is commonly used for tanks and pipes in areas that are not normally exposed to high temperatures or pressures, often this material is used for storing and transporting water. GRP/E is manufactured by forming tiny glass fibres into an overlapping mesh within a mould with a thermosetting plastic or epoxy resin placed between the layers. Curing of the plastic or resin then produces a lightweight, strong and generally corrosion free material. However it is a misconception to believe that once installed components made from this material require no maintenance or inspections and are suitable for indefinite service. Although none of the aqueous corrosion mechanisms associated with steel structures affect GRP/E materials there are several damage and degradation processes for these materials and also the possibility of defects going undetected during the manufacturing process or mechanical damage inflicted after installation.

Typical damage mechanisms for composite materials can include wall thinning due to exposure to chemicals which are incompatible with the resin used in manufacture. This can expose the underlying glass fibres and weaken the structure. Erosion and cavitation are two other internal wall thinning mechanisms which can also damage these materials internally. Delamination of the composite layers can occur due to thermal or chemical ageing of the resin layers or because the glass fibres have not been sufficiently wetted by the resin during manufacture. UV exposure eventually results in the breakdown of the external laminate layer known as “Chalking” although this usually only damages the outer surface layer. Additionally blisters can form between laminate layers causing bulging at the surface. Fatigue cracks can occur which propagate through either the resin and glass fibres or only the resin layer (matrix cracking). Unlike metals however, the crack initiation is always mechanical in nature. Cracks are usually observed at joints due to poor connections and the over-torquing of bolts.

The majority of defects in GRP/E structures can be identified with an external visual inspection. If internal inspections are possible then internal wall thinning is clearly identified by the exposed glass fibres that are left behind when the resin is lost. If an internal inspection is not feasible then ultrasonic wall thickness measurements can be taken to assess any damage. As with metal structures radiography may be used to identify cracking.

A useful source of further information is ISO 14692 Part 4 [11] which examines the fabrication, installation and operation of GRP piping. Many of the issues covered in the standard are equally applicable to GRP components other than piping, including the guidance provided on inspection of this class of materials.

2.6.7 Buried Pipes

Metallic pipes and tanks buried below ground would, if left unprotected, undergo external corrosion depending on the material composition and the local environmental conditions. In order to prevent corrosion and subsequent failure of the pipe or tank, the exterior surfaces of buried metallic structures are typically protected by both a coating and a cathodic protection system.

Where equipment is protected by a cathodic protection system then monitoring of the electrical potential of the protected structure at an adequate number of points along the buried pipeline or around the tank will give an indication that the cathodic protection system is functioning correctly in order to protect the outer surface of the structure. However this will not give any information as to the effect of corrosion process’s occurring internally or identify any defects which may be present within the structures.

Inspection of buried pipes and tanks is obviously much more difficult than for exposed structures. Visual inspections, and NDT techniques are not usually possible without prohibitively expensive and disruptive excavations being carried out around the buried structure. Inspections are usually only possible in the case of underground pipes which run within a tunnel or trench. Depending on the accessibility, a visual inspection and other NDT techniques may be carried out in the same way as for structures above ground.

For large underground pipelines which have been built to accommodate intelligent pigs, then this is the best technique to inspect the internal surface of a pipeline. Pigs are able to make continuous ultrasonic wall thickness measurements over the entire length of the pipeline. This is not possible however in small sections of pipes that might, for short distances, pass below ground. This may typically be observed where pipes cross underneath roads. In order to inspect these pipes a technique known as Guided Wave Ultrasonics is able to make wall thickness measurement up to 25m along a pipe from the location that the equipment is attached to an above ground section.

More information on the degradation and protection measures, specifically cathodic protection, that can be applied to buried steel structures can be found in API Recommended Practice 1632 [12].

3.0 Management of Ageing

Plant ageing should be managed as part of a well structured Health, Safety and Environment Management Systems (HSEMS). In many cases the term "ageing" may not be mentioned explicitly but management of ageing issues should be catered for in the management of system integrity and functionality and covering all asset types.

A well structured and maintained HSEMS document is a means of identifying and setting down a commitment to how a business will manage health, safety and environmental issues. Larger businesses will develop such a document and refer to the many standards, procedures and methods by which they will maintain performance across all sections of their business.

Many small and medium sized businesses will also have the required standards and procedures documented but they may not have these requirements organised into a document which explains how these requirements will be implemented and maintained. These standards and procedures will refer to both operational and process health and safety issues.

The identification and management of ageing plant issues in relation to process safety is recognised in a number of key risk control systems which must be identified and documented in order that they are regularly reviewed and updated. Key elements include:

- Maintenance Management Systems
- Asset Management and Integrity Systems
- Audit and Inspection regimes
- Risk Assessment Management processes
- Management of Change procedures
- Permit to Work
- Responsibilities and Communications
- Training and Competence development

A key stage in managing ageing plant issues in any business is identifying what hardware and resources the business has; this would identify the potential extent of the ageing issues and the way in which it will be managed. This should be linked with an action plan that will encompass implementation and monitoring of the risk control systems to avoid major incidents.

In recognising ageing mechanisms, businesses can identify key performance indicators (KPIs) which can be monitored to identify how effectively the risks are being controlled. These indicators would form part of any Action Plan with target completion of leading indicators normally within one year, and with reviews on progress throughout the year.

Both leading and lagging indicators must form a balanced approach to managing the risk control systems to ensure the risks are controlled to an acceptable level, the approach to this is explained fully in the HSE publication HSG 254, Developing Process Safety Indicators [13].

Every business is different and therefore the number and focus on KPIs will differ. There is no right system for all and it is a requirement of the management team to identify the key process indicators they wish to monitor in relation to ageing plant issues and the control of major hazards.

The following are just some of the key indicators to be considered.

Leading Indicators

- Number of planned inspection,
- Number and frequency of audits
- Planned replacement schedules for plant and equipment
- Number of Emergency Response exercises planned.
- Planned number of tests done on safety critical equipment.
- Training plans for identified staff and staff numbers attending.
- Planned procedure reviews

Lagging indicators

- Number of major failures of plant and equipment.
- Number of uncontrolled releases of product.
- Number of reworks to maintenance activities
- Number of outstanding audit/Inspection action items.
- Number of alarm/instrument failures during testing
- Number of incidents when working under a Permit to Work system
- Number of incidents due to Human Error.

A number of major incidents in the oil and gas and major hazard industries over the past years have been caused by failures of plant and equipment, the condition of which has deteriorated over a period of time for various reasons. Recognising the ageing mechanisms that affect the process and then introducing and maintaining a structured management system approach to mitigate the potential for failure will significantly reduce the incidents of major accidents in the industry.

As an illustration, in one incident a redundant branch pipe, which was still attached to the live main transfer line, fractured due to vibration fatigue. The branch had been in place since the 1950s and had been left unsupported after a change to its configuration pre 1987. In a period of four years from 1998 there had been an increasing number of shut downs and start ups which added further fatigue and shock loading to the branch line, during this time a number of incidents had occurred in which vibration was a relevant issue.

The pipework was inspected for corrosion only and there were no proactive surveys for dead legs/redundant drains etc.

The key Risk Control Systems missing from this operation would be as follows.

- Management of Change procedures (Not recognising the effects of change when the branch was made redundant)
- Asset Integrity Management System (Weak assessment approach that did not include dead legs/redundant drains etc).
- Risk Assessment/Management processes. (Not identifying the risks of leaving unsupported redundant pipework tied to a live system)
- Audit and Inspection Regimes.(Not identifying the potential for failure of pipelines due to vibration. Poor inspection procedures).
- Procedures (Weak procedures that did not identify and act on a trend of an increasing number of vibration related incidents over a period of two years prior to the incident)
- Training and Competence (Staff did not recognise the potential for failure of the branch during the continuing maintenance and operational activities of the plant).

A key reference document is the HID CI, SI Inspection Manual [14] which offers overall guidance on the completion of inspections in the Chemical, Oil and Gas onshore sectors. Table 5 summarises the safety management and risk control systems in relation to ageing plant.

Table 5: Safety Management and Risk Control Systems in relation to Ageing Plant.

Risk Control System	Considerations	Ref.
Plant design and modification. *(Leadership & commitment)*	• An Asset Integrity Management Policy communicated and understood at all levels. • Design standards/codes of practice monitored, updated and understood to recognise the potential effect of ageing. • Performance of assets are monitored and discussed at senior level (Improvements, failures, anomalies etc.) to recognise a potential ageing issue. • Contractor and third party standards clearly defined and tested.	*HSG65 Chp 3 & 4 [15]* *HSE RR509 Plant Ageing Chp 2 [1]*
Responsibilities and Communication *(Organisation & responsibilities)*	• A clear organisational structure with identified responsibilities set out in job descriptions. • Clear internal and external communication routes through regular Engineering/Operational meetings, Contractor/Third Party Management meetings etc.	*HSG65 Chp 2 & 3* *HSE RR509 Plant Ageing Chp 2*
Training and Competence development *(Resources)*	• A competency development programme for critical staff containing the ability to recognise ageing mechanisms. • A structured training plan in place. • Job continuity plans to retain job knowledge and operational skills.	*HSG65 Chp 3 HSE Human Factors Briefing Note No2 – Competence [16]*
Procedures *(Documentation / Planning)*	• Technical Safety Reviews on critical equipment. • Operational procedures that interface with Maintenance Management to avoid repeat work and subsequent increased stress and reaction of plant to downtime. • Clear leading/lagging KPIs monitored on a regular basis to track performance. • Proactive approach to identifying potential incidents and near misses which may identify ageing issues. • The development of a Plant Defect Reporting System	*HSG65 Chp 4* *HSE Technical Measures Document – Maintenance Procedures [17]*
Risk Assessment /Management processes *(Hazard & Effects Management)*	• Risk Assessment programme relating to the impact of failure and the effect of process change • Hazard identification and fitness for service reviews to identify the effect of ageing mechanisms such as wear, corrosion, damage, vibration, pressurisation, atmospheric exposures etc. • Risk based inspection programme identifying ownership and rational for change. • Accident/incident investigation procedures with clear action tracking and close out procedures.	*HSG65 Chp 4* *HSG254 Risk Control Systems [13]*

Asset Integrity Management Systems *(Implementation)*	• AIMS plan and procedures in place to identify HSE Critical plant and equipment. • Clearly identified and accessible Asset Register documentation to ensure action is taken at the correct intervals. • Reviewed at clearly defined intervals to ensure correct data is maintained.	*HSE RR509 Plant Ageing Chp 4*
Management of Change procedures. *(Implementation)*	• A clearly defined Management of Change procedure. • Clear lines of responsibility and communication to agree and implement change. • Consideration of organisational change and its influence on systems and human factors.	*HSE RR509 Plant Ageing Chp 2* *HSE Briefing note 11 - Organisational Change [18]*
Maintenance Management Systems *(Implementation)*	• A well structured and understood Maintenance Management and Inspection System that interfaces with operations. • Replacement policy in place for HSE critical plant and equipment.	*HSE RR509 Plant Ageing Chp 4*
Audit, Review and Operational Inspection regimes *(Audit & review)*	• An audit programme is in place to ensure all elements of a management system related to the controlling of ageing plant and equipment issues are maintained. • A operational inspection regime which highlights the need to identify ageing mechanisms such as corrosion, external damage, vibration, exposure to the elements, impingement of harmful releases, identification of dead legs, etc. • Clearly developed corrective action plans with close out tracking systems.	*HSG65 Chp 6* *HSE RR509 Plant Ageing Chp 4.5*

The development of a structured Management System with reference to key elements relating to potential Ageing Plant and Systems issues is vital to reduce further the potential for Major Accidents in the Chemical, Oil and Gas Industry.

4.0 EC&I Specific Guidance

4.1 Introduction

This section is intended to provide high level guidance regarding technical and managerial issues surrounding ageing Electrical, Control and Instrumentation (E/C&I) systems and equipment.

Examples of such systems and equipment include:- relays, switchgear, electric motors, starters, level sensors, pressure sensors, transmitters, PLCs, DCS, SCADA, valves, pumps, etc.

In safety systems, these systems and equipment are employed to provide emergency shut-down systems, trips, alarms etc, which either separately or in combination with other systems ensure safety in process plant, e.g. overfill protection systems for bulk storage tanks.

Any electrical, control or instrumentation system is potentially within scope if either
(a) its purpose is to ensure that the plant or equipment stays within safe operating limits, or
(b) its failure could cause a dangerous situation.

In terms of managing major hazards, it must be clear which of these E/C&I systems are safety critical. This can be established through a variety of techniques including SIL assessment, HAZID and HAZOP studies, and the identification of safety critical systems and the setting of performance standards for these. SIL assessment techniques are described in, for example, BS EN 61508-5, *Functional safety of electrical /electronic/programmable electronic safety-related systems*, *Part 5: Examples of methods for the determination of safety integrity levels* [19].

E/C&I systems and equipment can be affected by the same degradation mechanisms as mechanical equipment, such as corrosion, erosion, fatigue, etc. However, they can also be subject to more E/C&I specific degradation mechanisms. These include physical mechanisms such as impact damage or surface abrasion, overheating/ burn damage, blockage, fouling or poisoning or the formation of 'tin whiskers' or dry joints, and instrumentation aspects such as instrument drift. Poor quality control of plant painting activities can (as with mechanical plant) affect E/C&I equipment, for example the painting of flameproof glands, or painting over instruments. There are also significant issues relating to the relatively shorter working life of E/C&I systems compared to some mechanical plant, and the degree to which some types of instrumentation and control systems, and the software that is used in them, can become obsolete or difficult to support.

On the other hand, software-based E/C&I systems can provide significant advantages to safety in terms of improved control and diagnostic information, as well as providing economic advantages compared to older style analogue systems.

Since the 1990s, international standards such as BS EN 61508 and IEC 61511 *Functional safety – Safety instrumented systems for the process industry sector* [20] have provided a lifecycle-based framework for successfully deploying such systems and a number of Guidance documents have been produced, for example EEMUA 222, *Guide to the Application of IEC 61511 to safety instrumented systems in the UK process industries* [21].

The Guidance set out here draws on these standards and provides further guidance on issues particularly related to "ageing" and how they can be managed effectively.

In determining how well E/C&I ageing plant issues are being managed there are certain key themes, as follows:

1. Is the E/C&I equipment “ageing”?
2. Is there an understanding of the safety significance of the E/C&I equipment?
3. Are there plans for the likely replacement of at least some of the E/C&I equipment during the lifetime of the whole plant? Is there an awareness of the technical and resource issues?
4. Are there adequate arrangements for Maintenance and Procurement of modern E/C&I equipment?
5. Are there adequate arrangements for Management of Change (MoC)?

This guidance is therefore structured around the above key themes to help promote awareness and understanding of the issues.

Specialists may wish to refer to more detailed guidance which deals exclusively with E/C&I matters. The guidance, E/C&I Plant Ageing: A Technical Guide for Specialists managing Ageing E/C&I Plant [22], is being developed and will be published in the near future. It will also include a discussion of ageing mechanisms and how to recognise them, a list of relevant standards, and references to other relevant literature.

4.1.1 What is “Ageing E/C&I equipment”?

There is no precise definition for “ageing E/C&I equipment” but, in general terms, the overall definition of ageing offered in Section 1.3 is considered sufficiently broad in nature to encompass E/C&I ageing mechanisms.

Some specific age related E/C&I issues are discussed below:

4.1.1.1 C&I Equipment Lifecycles

With care, even quite sophisticated control and instrumentation (C&I) equipment can be kept working to a remarkable age. Other equipment may need replacing after quite short timescales. Digital (or software–based) equipment shows a tendency to have significantly shorter lifecycles. For planning purposes, the lifetime of a DCS/SCADA can be taken as 15 to 20 years. However in some instances the lifetime may be as short as 10 years, while with care and effort some DCS/SCADA systems can be kept operational for longer periods.

DCS/SCADA equipment is not normally classified as safety-critical, but there may be ageing-related unreliability of the DCS/SCADA which will increase the demand rates on the safety-critical systems.

E/C&I equipment life can be extended if good support arrangements are in place either from the Original Equipment Manufacturer (OEM) or a specialist contractor. However, in general, the following principles apply:

- C&I obsolescence is usually ultimately driven by spares availability.
- Older C&I equipment will often be analogue.
- Almost all new equipment is digital or software-based.
- Demonstrating the safety of new digital equipment requires significant effort but in return can provide significant safety advantages (as outlined in section 4.1).

Having the capability to assure the specification and safety performance of new digital equipment is therefore a key factor in managing the obsolescence of older C&I equipment.

A related issue is the ability to support and maintain any software associated with C&I equipment. It can be particularly difficult to find competent people with the skills and experience to safely maintain and make changes to older programmable logic systems and control software. This applies especially where documentation is incomplete or inaccurate, or where software languages used in older equipment have become obsolete.

4.1.1.2 Cable Ageing

Cable ageing is dependent upon the type of cable (e.g. whether or not it is armoured), the type of insulation (e.g. some types of insulation degrade more rapidly when exposed to sunlight), the potential for mechanical or thermal damage, and humidity. Well-specified cabling can survive for twenty years or more outdoors and for thirty years or more indoors.

One reference source [23] suggests 60 years as the accepted economic life for cables. This benchmark value is of course dependent on many factors, such as environmental factors and physical damage. Appropriate reviews should be carried out periodically.

4.1.1.3 High Voltage (HV) Equipment Life Expectancy

High Voltage (HV) equipment generally comprises switchgear, transformers and rotating equipment (motors and generators). Failures of HV equipment can be sudden, severe or even catastrophic. A number of sophisticated condition monitoring techniques are available for monitoring the state of ageing HV plant.

Benchmark values for the life expectancy of HV equipment have been published (see Ref. [23] for details), as follows:

Transformers (132kV)	30-40 years
Transformers (<132kV)	50 years
Switchgear	30-60 years

These benchmark values are in no way assured. They are very dependent on many factors, such as environmental factors, standard of maintenance, and physical damage. Appropriate reviews should be carried out periodically. Some HV equipment may only be operated infrequently; in those cases the equipment should be subject to risk assessments to review degradation mechanisms since the last operation.

4.1.2 Significance of E/C&I Equipment Lifetimes

The significance of the above notional values for equipment lifetimes is that, whereas HV equipment may (with proper maintenance) last through the entire life of a typical plant (say 30 to 40 years), it is unlikely that the same can be said for C&I equipment. Hence operators should expect to have to carry out at least one mid-life refit of C&I systems.

4.1.3 Issues related to Ageing E/C&I Equipment in incidents

The Ageing Plant Phase 1 report [2] includes an account of a data review to identify where ageing was a significant factor in major loss of containment accidents. With regard to E/C&I the following conclusion were drawn;

- E/C&I issues are a significant factor in around 10% of major accidents in the MARS European Major Accident database.

- The biggest single factor in all E/C&I failures is associated with Level Detection, often resulting in vessel overfill and loss of containment.
- Other significant causes of E/C&I failure include Loss of Site Power, Lightning/Earthing and Software failures, including examples of issues caused during upgrading to modern DCS control systems.

The review concluded that there is a need, on all high-hazard plants, for very firm links between:

(i) the Safety Report (identifying the Safety Critical Elements (SCEs)) and

(ii) the Maintenance, Inspection and Test (MIT) schedule (taking each and every SCE and going right down to individual instruments, logic elements and output devices, also addressing potential initiating events like loss of supplies and lightning strike, and defining specific test requirements and frequencies).

The MIT schedule, based on the Safety Report, needs to be matched with KPIs measuring the backlog of safety-related maintenance, to make sure that management can see that the appropriate MIT work is being completed.

4.2 E/C&I Maintenance Management

Good maintenance management processes and practices are central to ensuring that ageing safety-related E/C&I systems and equipment continue to operate reliably and with good availability. These issues are dealt with in detail in the referenced standards and guidelines, but in summary key aspects of maintenance management are as follows:

1. Maintenance Planning
    a. Is E/C&I equipment classified according to its safety function?
    b. Are suitable performance standards established?
    c. Are there Maintenance, Inspection and Testing (MIT) plans in place?
    d. Is the MIT backlog monitored?
    e. Are there suitable robust arrangements for the control and management of overrides?

2. Procurement - Spares and Support Issues
    a. Spares availability and storage
    b. Contractual arrangements
    c. Change control
    d. Contingency planning and related QA issues

3. KPIs for Management of C&I Ageing – lagging and leading indicators

4. Plant History
    a. Are equipment failure data records kept?
    b. Is there learning from others' failure?

5. Specific Ageing and Failure Mechanisms

Key aspects are discussed further below.

4.2.1 Maintenance Planning

Good maintenance planning is absolutely key to the lifecycle management of safety-related E/C&I equipment. Figure 11 presents a diagram showing how the Safety Report should relate to maintenance practices.

The key aspects are:

- Safety-related E/C&I equipment should have defined performance standards.

- Safety-related E/C&I equipment should have Maintenance, Inspection and Test (MIT) plans in place.

Testing (and proof testing) should be designed to confirm that safety-related functions are being performed properly and most importantly that there are no unrevealed failures (see HSE CRR 428, *Principles for proof testing of safety instrumented systems in the chemical industry* [24]).

- Test frequencies should preferably be risk-based.

- Non safety-related E/C&I systems, if they fail, may challenge safety-related equipment.

- Good practice is to have a maintenance policy document for E/C&I equipment.
- There should be clear evidence of well-planned MIT arrangements and activities, including evidence (KPIs) that the maintenance backlog is being properly managed.
- There should be robust managerial controls over the assessment, approval, application and removal of all overrides.

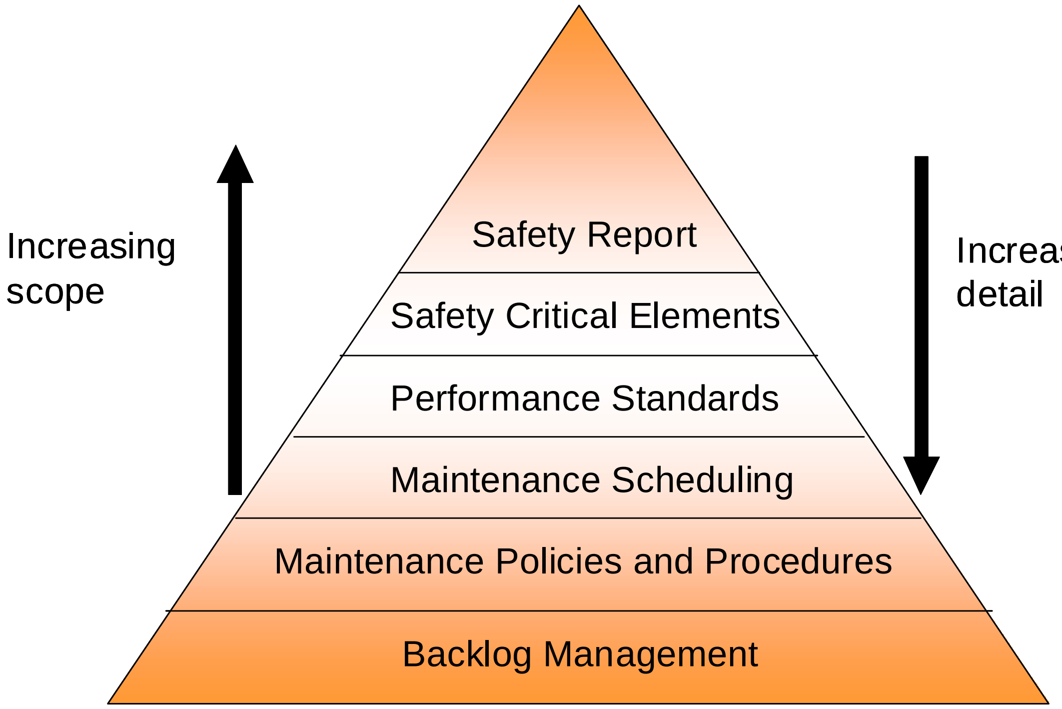

Figure 11: The relationship between the Safety Report and maintenance practices

4.2.2 Procurement – Spares and Support Issues

So-called E/C&I 'ageing' or obsolescence in practice is most often determined by spares availability. OEM contracts may expire after a given number of years, and spares may no longer be available. However, E/C&I equipment can in some instances, and with care and forethought, be operated safely well beyond this point. Issues to consider include:

- Adequate spares holding, in good storage conditions.
- Long-term support contracts with the OEM.
- Specialist contractors for some component repairs.
- Awareness of the risk of lack of change control over time in the supply of spares from the OEM – especially for digital components.
- QA issues around buying second-hand components or potentially faked components.

4.2.3 Plant History and Other Experience

It is important to identify and record the performance of E/C&I equipment including any in service faults or failures and problems discovered during testing and inspection. Some form of accessible record of plant component failures is highly desirable. Such a record achieves, inter alia, the following:

- It enables the Maintenance Department to identify where re-working is needed and where repeat failures occur, thus enabling smarter solutions to plant problems and feedback to suppliers to improve or change designs
- It improves awareness and accuracy of component reliability data and failure modes.
- It enables Technical or Engineering Departments to identify those components which have a significant adverse contribution to plant availability and safety.
- If relevant, it enables more accurate Quantified Risk Assessments of the plant.

Ideally, an organisation should also have access to cross-industry sources of information which improve awareness, and enable learning from, incidents and accidents which have occurred elsewhere.

4.2.4 KPIs for Management of E/C&I Ageing

Extensive advice on the use and development of process safety KPIs is available elsewhere – see for example:

- HSE, *Developing Process Safety Indicators*, HSG 254 [13]
- Process safety KPI downloads available from www.aiche.org/ccps/metrics

Both leading and lagging indicators should be used as KPIs. Lagging indicators measure *outcome*, whereas leading indicators measure *processes or inputs that are needed to deliver the desired safety outcome.* In general, lagging indicators are easier to measure and more reliable, but they only show what has already happened, whereas good leading indicators should forewarn of future difficulties.

Table 6 presents some ideas for Process KPIs related to E/C&I ageing.

Table 6: KPIs for management of E/C&I ageing

Item	Description of issue	Detail
1	Need for leading and lagging indicators	Lagging indicators measure *outcome*. An outcome is the desired safety condition that management arrangements should seek to deliver. Lagging indicators show when things have been going well or badly, e.g. by measuring incidents or accidents. Leading indicators measure *processes or inputs that are needed to deliver the desired safety outcome*, e.g. by measuring whether MIT work has been completed to schedule.
2	Lagging indicators for E/C&I	Examples: 1. Number of defect reports per month for E/C&I equipment 2. Rising trends in failure rates for specific components or systems 3. Overrides: 'spot' values of the total number of overrides extant across the plant 4. Overrides: total number that have been newly applied during (say) the last month

		5. Incidents arising from E/C&I failures 6. Safety or business-critical system downtime due to E/C&I failures
3	Leading indicators	<u>Examples</u>: 1. E/C&I planned maintenance backlog 2. E/C&I reactive maintenance backlog 3. Maintenance support – remaining duration of existing contractual support 4. Spares holding for critical components 5. Management of Change (MoC): numbers of E/C&I MoC proposals in preparation or pending approval 6. MoC: numbers of E/C&I MoC proposals pending implementation 7. MoC: numbers of MoC proposals awaiting close-out of commissioning test reservations

4.3 E/C&I Management of Change

Suitable arrangements and skills for Management of Change (MoC) are essential for managing ageing E/C&I equipment.

Solutions to E/C&I refurbishment projects or upgrades using purely analogue equipment are now extremely difficult, since new analogue equipment is becoming increasingly difficult to procure. Hence almost all new E/C&I equipment is digital or software-based.

In the recent past, there has been a record of some E/C&I projects (and in the wider sense, major IT projects in general) failing to achieve their objectives. Some of these failures have been due to the very complexity that software-based solutions make possible. Other failures have been due to the problems of safety justification of software-based systems.

Hence the replacement of ageing E/C&I equipment requires proper arrangements for MoC. Key elements of good practice for MoC, include:

1. High-level issues about the Company MoC capability.
2. Software maintenance and configuration management.
3. Project management issues.
4. Competency management for E/C&I maintenance, testing, modification, and refurbishment.

Key aspects are discussed further below.

4.3.1 Management of Change (MoC) Capability

In order to be able to replace ageing analogue equipment with digital equipment there is a need to have robust MoC arrangements in place in accordance with IEC 61508 (Functional Safety of electrical/electronic/programmable electronic safety-related systems) or IEC 61511 (Functional safety – Safety Instrumented systems for the process industry sector).

The main issues for MoC are:

1. Do staff have the necessary skills?
2. Does the MoC process cover the essential aspects of IEC61508/IEC 61511? These include:
    a. Functional Safety Management
    b. SIL requirements assessment
    c. Equipment SIL rating
    d. Software maintenance arrangements
    e. Software configuration management
3. Learning from the past

4.3.2 Software Maintenance and Configuration Management of Plant Computer Control Systems

Plant computer control systems such as DCS can be very large and complex, sometimes with millions of lines of code. Maintenance of these systems requires care, attention, effort and resources.

DCS should not be used for critical safety applications, but may have a role in providing enhanced alarm and diagnostic information which can aid safety and hence it is important to ensure that DCS work to a high level of reliability and availability, and that changes to them are effectively managed

A particular issue with older programmable DCS/SCADA systems may be the use of obsolete computer languages. The availability of programmers for old languages can be an issue.

Many of these issues may also apply to smaller software-based systems, e.g. discrete plant monitoring systems, some of which may be safety-related.

Alarm management systems, where used to prevent the operator seeing excessive numbers of alarms simultaneously, should be designed using best practice such as EEMUA 191 [25] and the Human Factors HSE Inspectors Toolkit [26].

Adequate controls should exist to ensure that DCS/SCADA software cannot suffer unplanned changes and interference. These controls may include firewalls and software MoC arrangements. General advice on data security issues in industry can be obtained from the following sources:

- HSE CRR/408, *Safety Implications of Industrial Uses of Internet Technology* [27]
- The Centre for the Protection of National Infrastructure (CPNI) publishes good practice guides on its website: http://www.cpni.gov.uk/ProtectingYourAssets/scada.aspx

4.3.3 Project Management Issues for Large E/C&I Refurbishment Projects

In the recent past, there has been a record of some E/C&I projects (and in the wider sense, major IT projects in general) failing to achieve their objectives. Some of these failures have been due to the very complexity that software-based solutions make possible. Other failures have been due to the problems of safety justification of software-based systems.

Sound project management arrangements can go a long way to help mitigate the risks of project failure. This issue was addressed in some detail in the Royal Academy of Engineering/British Computer Society (RAE/BCS) 2004 report *The Challenges of Complex IT Projects* [28].

The report also contains a succinct list of key issues for senior management for IT projects, most of which relates also to large E/C&I refurbishment projects on modern process plant.

5.0 Where to find out more

In addition to the specific references quoted in this report, the following sources provide further useful background on Ageing Plant.

5.1 Accident statistics and analysis

- Major Accident Reporting System (MARS)
- Major Hazard Incident Data Service (MHIDAS)
- A Review of High-Cost Chemical/Petrochemical Accidents Since Flixborough 1974, IchemE Loss Prevention Bulletin April 1998
- Loss Prevention Bulletin, various issues
- Hazardous Cargo Bulletin, various issues
- Large Property Damage Losses in the Hydrocarbon Chemical Industries – A Thirty Year Review, 2001
- The Costs of Accidents at Work, Health and Safety Executive, 1997
- 1999 Process Safety Performance Measurement Report, API
- Report on a Study of International Pipieline Accidents, Health and Safety Executive, CRR 294/2000

5.2 Ageing mechanisms and their management

- API RP 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry
- API RP 574, Inspection Practices for Piping System Components
- RR 076, Machinery and Rotating Equipment Integrity Inspection Guidance Notes
- RR 253, Piping Systems Integrity, Management Review
- API Standard 1160, Managing System Integrity for Hazardous Liquid Pipelines.
- Corrosion, Shrier, Elsevier
- Fitness-for-Service and Integrity of Piping, Vessels and Tanks. ASME Code Simplified. G Antaki

5.3 Good practice guides

- PAS 55, Asset Management, The Institute of Asset Management
- Best Practice for Risk Based Inspection as a Part of Plant Integrity Management, CRR 363/2001

References

1 Plant ageing, Management of equipment containing hazardous fluids or pressure, HSE Research Report RR509, HSE Books, 2006

2 Plant Ageing Study – Phase 1 Report, ESR/D0010909/003/Issue2, A Report prepared for the Health and Safety Executive, 27th February 2009

3 Energy Institute Document "Guidance for Corrosion Management in Oil and Gas Production and Processing"

4 NACE Corrosion Engineer's Reference Book, 3rd Edition

5 API 571, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry

6 HSE Research Report 076, "Machinery and Rotating Equipment Integrity Inspection Guidance Notes"

7 API Recommended Practice 573, "Inspection of Fired Boilers and Heaters"

8 Concrete Repair According to the New European Standard EN 1504, Prof Dr Ing M Raupach, RWTH Aachen, ibac

9 EN 1504, "Products and systems for the protection and repair of concrete structures"

10 BS EN 12696:2000, "Cathodic Protection of Steel in Concrete"

11 ISO 14692-4:2000, "Petroleum and natural gas industries -- Glass-reinforced plastics (GRP) piping -- Part 4: Fabrication, installation and operation"

12 API RP 1632 (2002), "Cathodic Protection of Underground Petroleum Storage Tanks and Piping Systems"

13 HSG 254, Developing Process Safety Indicators, HSE Books

14 HID CI, SI Inspection Manual, issued 11/4/2001, HSE website

15 HSG 65, Successful Health and Safety Management, HSE Books

16 HSE Human Factors Briefing Note No. 2 – Competence, HSE website

17 HSE Technical Measures Document – Maintenance Procedures, HSE website

18 HSE Human Factors Briefing Note No. 11 – Organisational Change, HSE website

19 BS EN 61508:2002 Functional safety of electrical/electronic/programmable electronic safety-related systems

20 IEC 61511 Functional safety – Safety instrumented systems in the UK process industries

21 EEMUA 222:2009 Guide to the Application of IEC 61511 to safety instrumented systems in the UK process industries

22 E/C&I Plant Ageing: A Technical Guide for Specialists managing Ageing E/C&I Plant

23 AEA Technology, Developments in electrification systems – Life expectancy of electrical equipment, AEATR-EE-2005-030, June 2005

24 HSE CRR 428(2002), Principles for proof testing of safety instrumented systems in the chemical industry

25 EEMUA 191:2007 Alarm systems - a guide to design, management and procurement

26 Human Factors HSE Inspectors Toolkit, HSE web-site

27 HSE CRR/408(2002), Safety Implications of Industrial Uses of Internet Technology

28 The Challenges of Complex IT Projects, Royal Academy of Engineering/British Computer Society, 2004

Published by the Health and Safety Executive 08/10

HSE

Health and Safety Executive

Plant Ageing Study

Phase 1 Report

Between 1996 and 2008 it is estimated that there have been 173 loss of containment incidents reported in RIDDOR that can be attributable to ageing plant. This represents 5.5% of all loss of containment events. The limited information provided in RIDDOR about the underlying causes means that it is difficult to identify which events may be age related: the actual number could be much higher than that quoted here.

Across Europe, between 1980 and 2006, it is estimated that there have been 96 incidents reported in the MARS database relating to major accident potential loss of containment which are estimated to be due to ageing plant. This represents 28% of all reported 'major accident' loss of containment events in the MARS database and equates to an overall loss of 11 lives ,183 injuries and over 170Million € of economic loss.

As the MARS data provides the more detailed and comprehensive insight into the incidents and causal factors and is specifically related to potential major accident hazard events, it is considered that this represents a more realistic indication of the extent and severity of ageing plant and its contribution to major accidents. This leads to the conclusion that ageing plant is a significant issue.

Onshore chemical plant in the UK is ageing. Health and Safety Executive (HSE) field inspectors often have to consider the Operators' safety justification for continued use of ageing plant taking account of a variety of issues such as usage, design life, known research, known operational and failure history, maintenance and inspection history, etc. The issues also need to be considered against a background of increasing competition from overseas, and the pressure on resources and investment which this has had over recent years, with reductions in manning levels, early retirement of experienced staff, and pressure on operating budgets.

This report and the work it describes were funded by the Health and Safety Executive (HSE). Its contents, including any opinions and/or conclusions expressed, are those of the authors alone and do not necessarily reflect HSE policy.

RR823

www.hse.gov.uk