First Libyan International Conference on Engineering Sciences & Applications (FLICESA_LA)
13 – 15 March 2023, Tripoli – Libya

Enhancement of Safety and Reliability in Refineries by Effective Assets Integrity Management: A Case Study of AGOCO Refineries in Libya

Iftikhar Ahmad, Youssef El Kizza and Abdelsalam Sadawi
Arabian Gulf Oil Company (AGOCO), Libya
ahmadift1953@gmail.com

Abstract: Petroleum refineries perform multiple phase operations characterized by a high level of risk. Evidence based major accidents, around the world, that have occurred within the last three decades in the petroleum refineries indicate losses estimated in billions of US dollars. Many of these accidents are catastrophes. These accidents have resulted in production loss, asset damage, environmental damage, fatalities and injuries. A comprehensive approach is needed to ensure that refinery is operated in a safe, reliable, environmentally sound and economic manner. To fulfill the requirement, a refinery incorporates an effective assets integrity management. This paper presents assets integrity management of AGOCO refineries (Sarir and Tobruk refineries) in Libya

The effective and successful life cycle refinery integrity management is based on following aspects: (a) feasibility, (b) design, (c) procurement, (d) fabrication, (e) modification, (f) transportation and storage, (g) pre-commissioning and commissioning, (h) handover, (i) operation and maintenance, (j) suspension/abandonment. Since the AGOCO refineries are in operation, therefore, this paper is limited to the aspects of operation and maintenance. As each facility is unique, a comprehensive approach is needed to ensure that refinery is operated in a safe, environmentally sound and economic manner.

The following elements are developed for the operational phase to ensure that adequate management practices are in place to assess failures, and manage and respond to emergencies: (i) Failure assessment plan - The failure assessment plan consider failure causing and contributing factors and provides critical information to integrity management plan (IMP). (ii) Emergency response plan - The emergency response plan is designed to ensure the operator is prepared to deal with accidents and incidents in a timely manner to aid in the reduction of consequences. (iii) Remaining life assessment plan - The remaining life assessment provides input into the economic viability assessment of the refinery's vessels and equipment. The external environment on refinery's equipment materials (pipe, welds, coatings, etc.) and the characteristics of fluids present in the equipment are the causes of refinery degradation. Corrosion is the most prevalent threat to a refinery. It is a time-dependent phenomenon. The assets integrity management of refineries through corrosion mitigation, monitoring and inspection strategies is presented. The external corrosion on surface equipment, pipes and tanks is controlled by coatings while external corrosion on buried structures is controlled by combination of coatings and cathodic protection. The internal corrosion is controlled with a combination of chemical treatment, internal coatings and process control. The monitoring and inspection techniques provide a way to measure the effectiveness of corrosion control systems and provide an early warning when changing conditions may be causing corrosion and safety problems. The importance of risk based inspection and its implementation is also discussed in this paper.

This paper describes a case study of integrity management system of AGOCO refineries (Sarir refinery and Tobruk refinery) in Libya. The study is based on standard practices of corrosion mitigation and inspection. Applying the data of this study safety and reliability will be enhanced in these and similar refineries.

I. Introduction

A refinery deals large amounts of hazardous and flammable substances and so can pose a serious threat to people and the environment, especially in the case of improper design, construction, management, operation or maintenance. An accident at a refinery may result in uncontrolled spills, fires and explosions, potentially leading to the loss of human life or to a major environmental catastrophe. At the same time refineries are also large, complex sites with many processes, several of which operate at very high levels of pressure and temperature. The refinery has a large number of storage tanks for crude oil and process fluids. This combination of factors makes refinery sites very vulnerable to a structural integrity that can eventually causes a loss of contaminants of process fluids, sometimes leading to a serious accident affecting workers, the environment, the surrounding economy and even on occasion the larger economy.

This paper presents a case study of assets integrity management of AGOCO (Arabian Gulf Oil Company) owned refineries in Libya namely Sarir refinery and Tobruk refinery. The basic information of these refineries is given below:

Table 1: Basic information of Sarir and Tobruk refineries

	Sarir Refinery	Tobruk Refinery
Refining capacity	10,000 bbl of crude per day	20,000 bbl of crude per day
Refining products produced	Naphtha, motor gasoline, jet fuel, diesel, heavy fuel oil (Atmospheric residue)	Liquefied petroleum gas (LPG), naphtha, jet fuel, diesel, heavy fuel oil (atmospheric residue)
Processing Units	Desalter unit – 1 Atmospheric distillation unit – 1 Naphtha hydrotreatment unit – 1 Reforming unit - 1	Desalter unit – 1 Atmospheric distillation unit – 1 LPG Sweetening unit - 2
Product storage facilities	Crude Oil Tank – 1 Naphtha, Jet Fuel Tanks, & Reformate Tanks – 3 Motor Gasoline Tanks- 4 Diesel Tanks – 3 Heavy Fuel Oil Tanks – 1 Slope Tank - 1	Crude Oil Tank – 1 Naphtha & Jet Fuel Tanks – 16 Diesel Tanks – 5 Heavy Fuel Oil Tanks – 2 LPG Bullets – 3 Slope Tank - 1
Utilities and others	Boilers – 2 Cooling Towers – 1 Separators – 2 Desalination Plant - 1	Boilers – 2 Cooling Towers – 1 Separators – 2 Desalination Plant - 1

AGOCO refineries are mature and reaching the point where structural integrity can be compromised due to the deteriorating condition of fundamental pieces of equipment. Tobruk and Sarir refineries were started in operation in1988 and 1991, respectively.

The importance of effective assets integrity management increases as the industry infrastructure continues to age. Assets integrity management refers to the management systems, strategies and activities aimed at maintaining plant assets in fit-for-service condition for the desired life of those assets. A successful assets integrity management program incorporates (i) design and planning, (ii) material selection, procurement and construction, (iii) corrosion mitigation, monitoring and inspection, (iv) maintenance, (v) operations, (vi) risk evaluation, and (vii) communication concepts. These concepts are interlinked. Since AGOCO refineries are already completes more than 20 years in operation so the first three concepts of assets integrity management mentioned above are not discussed in this paper. The importance of corrosion management increases as the industry infrastructure continues to age. Uncontrolled corrosion can cause release of hazardous substances and components or can reduce both the performance and reliability of equipment until their failure. Corrosion hazards can put at risk the safety and well-being of plant of both plant employees and the general public as well as lead to severe damage of process units, and in some cases shutdown of refinery operations.

Corrosion does not stand for a single phenomenon but is a generalized term to cover a destructive attack on a metal as a result of either a chemical or electrochemical reaction between the metal and various elements present in the environment. Corrosion of a metal occurs either by the action of specific substances or by the conjoint action of specific substances and mechanical stresses. Depending upon environmental conditions, corrosion can occur in various forms such as general corrosion, pitting corrosion, embrittlement, and stress corrosion cracking. The particular type of corrosion occurring in a specific component can often be difficult to classify. For example, several forms of corrosion (such as galvanic corrosion, pitting corrosion, hydrogen embrittlement, stress sulfide corrosion cracking) are characterized by the type of mechanical force to which the metal component is exposed.

The successful and effective assets integrity management is relied on both corrosion engineering and corrosion management. The objective of a corrosion management plan is to define all necessary activities to assure the integrity of the refinery facilities by control of corrosion. This will ensure consistent availability and safe operation of the production facilities in a refinery throughout the specified design life. The objective should be achieved in the most cost effective manner, by designing for mitigation of corrosion, for inspection and monitoring and for maintenance in a timely manner. The corrosion management plan of refinery facilities can be designed by understanding corrosion environment in the refinery facilities (Table 2).

Table 2: Typical refinery elements contributing to elevated corrosion rates

Refinery Element	Examples
Corrosive substances in feedstock or added or produced in process	Hydrogen chloride, hydrofluoric acid, amines, sulfuric acid, polythionic acids and other sulfur compounds, oxygen compounds, nitrogen compounds, trace metals, salts, carbon dioxide, and naphthenic acids.
Refinery processes incorporating extremes of temperature or velocity	Distillation, desulfurization, hydrotreatment, catalytic reformers, fluid catalytic cracker, hydrocracker, alkylation. In case of AGOCO refineries fluid catalytic cracker, hydrocracker and alkylation processes do not exist.
Local conditions	Age of equipment, volume and rate of production, atmospheric conditions (e.g., climate), planned and unplanned shutdowns.
Risk management measures	Frequency of inspection, risk assessment and ranking practices, equipment inventory management, maintenance and repair procedures, auditing and implementation of feedback, use of safety performance indicators.

II. History of Accidents in Refineries of European Union (EU) and OECD Countries

A number of EU (European Union) and OECD (The Organization for Economic Cooperation and Development) national government authorities have invested effort over the last several years, conducting substantial scientific research, field studies and accidental analyses, in order to assess the extent and severity of the aging phenomena in refineries and how to control its associated risks such as corrosion. A study presenting the history of accidents in EU and OECD countries has been found in the literature **[1].** This study of corrosion-related accidents in refineries is based on 99 incident reports, among them 59 are pre-2000 and 40 are 2000 and post-2000. The important refinery accidents in which corrosion of an equipment part was identified or suspected as being the key failure leading to the accident event have been presented in this study. The report focused on corrosion risks in refineries in EU and OECD countries, looking at lessons learned from past corrosion-related accidents at these sites. The analysis was conducted as part of the long-standing collaboration on lessons learned between the European Union and OECD countries in the OECD Working Group on Chemical Accidents.

The report on investigation reveals that most events were initiated by a leak, rupture or structural collapse as shown in Table 3. A leak consists of a release from a small opening that over time facilitate the formation of a pool of dangerous substances that may eventually catch fire or explode. A rupture generally results from a leak that releases a flammable substance internally which overtime increases pressure and explodes inside a pipe or tank, causing a rupture. Structural collapse is defined as an accident in which, according to the report, corrosion was first manifested in the destruction or collapse of the unit (e.g., collapse of the distillation tower) rather than in a localized leak or rupture. In the accidents studied and reported in this study **[1],** leaks were less likely to lead to explosions (vapor clouds) than ruptures and ruptures were less likely to lead to toxic releases. However, both scenarios seemed to be equally capable of resulting in a fire.

Table 3: Distribution of accidents for each type of failure

Effect	Toxic Release	Fire	Explosion	Undeclared
Leak	28	24	10	0
Rupture	9	18	19	2
Structural Collapse	0	1	0	0
Undeclared	2	2	0	0

Note: There may be more than one type of effect per accident **[2].**

III. Standard Practice in Asset Integrity Management

Plant integrity, safety and reliability are major concerns to all refinery operators and managers. As the plant is ageing the importance of assets integrity management is increasing. Increasing international consensus on good practices for managing physical assets led to the publication **[3]** PAS 55:2008, a specification based on the familiar BS ISO format used in such widely adopted standards as ISO 14001 for environmental management and OHSAS 18001 for safety management. Some other important safety regulations are shown below:

- Pressure Systems Safety Regulations (PSSR) 2000 (SI 2000 No. 128)

- Management of Health and Safety at Work Regulations (MHSWR) 1999
- The Provision of Use at Work Equipment Regulations (PUWER) 1998
- The Control of Major Accident Hazards Regulations (COMAH) 1999

A number of global energy and transport organizations have already been certified as complying with the standard and interest in the industrial community is growing rapidly. PAS 55 primarily focuses on managing physical assets, though the other broad categories of 'assets' such as human assets, information assets, financial assets and intangible assets (reputation, etc.) are considered where they have a direct impact on the effective management of physical assets.

PAS 55 defines 28 explicit requirements, arranged under 6 main groups within the quality management Plan-Do-Check-Act (PDCA) framework, which is given below in Figure 1.

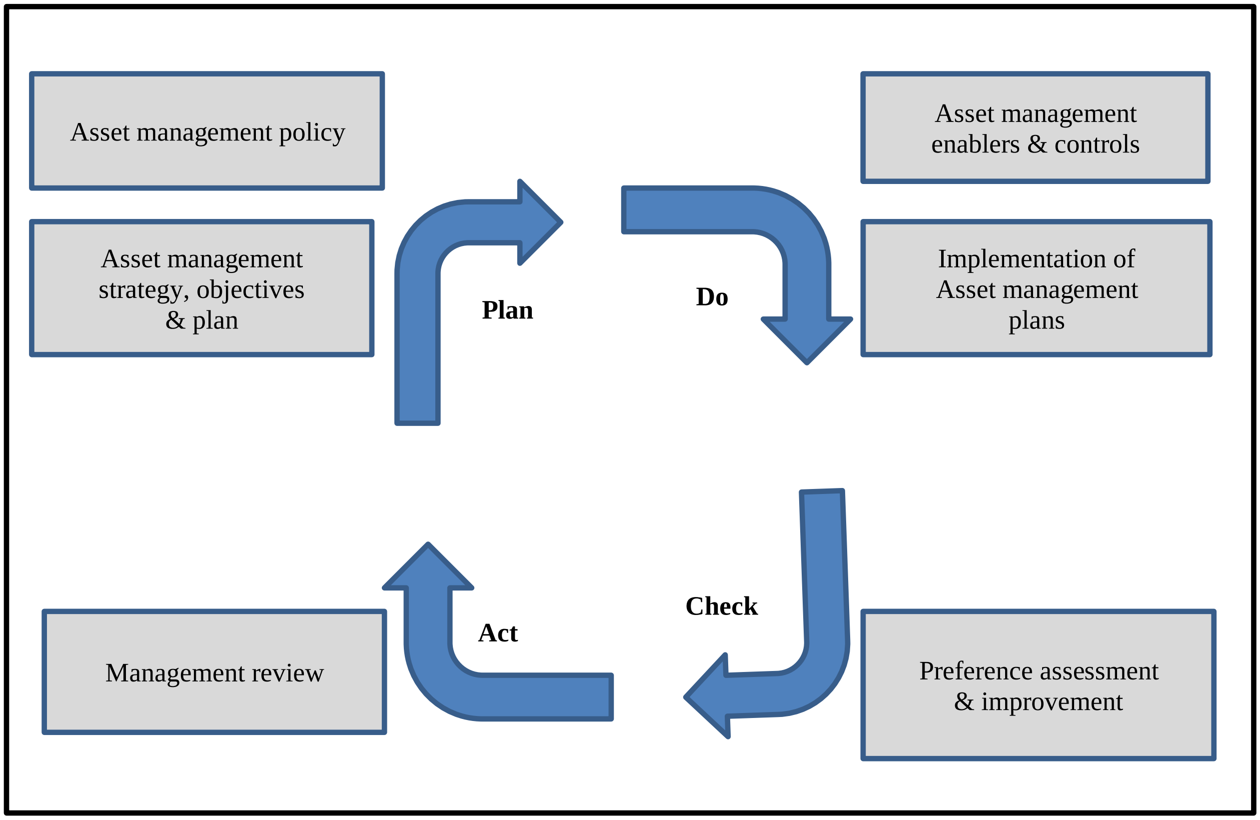

Fig. 1: Quality management plan

The successful and effective asset integrity management is relied on both corrosion engineering and corrosion management. The objective of a corrosion management plan is to define all necessary activities to assure the integrity of the production facilities by control of corrosion. This will ensure consistent availability and safe operation of the refineries throughout the specified design life. The objective should be achieved in the most cost effective manner, by designing for mitigation of corrosion, for inspection and monitoring and for maintenance in a timely manner. The corrosion management plan of refineries can be designed by understanding corrosion environment in the refinery facilities as shown in Table 4. In this table the processes existing in AGGOCO refineries have been considered.

Table 4: Typical refinery processes in AGOCO refineries

Distillation (Fractionation)	Distillation (fractionation) of the crude feedstock is the start of the refining process. Since it received untreated crude oil, it is exposed to all potential corrosive agents and their precursors in the feedstock. Like many refinery processes, distillation is heat intensive. Temperatures at the bottom are generally around 350 ºC to 400 ºC and gradually decrease as vapor rises in the column. As the vapor rises and cools, it separates into layers of product with the heaviest at the bottom (fuel oils, residue) to middle products (middle distillates, jet fuel, kerosene) and lighter products (naphthas) and light hydrocarbons. Residue at the bottom of the column are further distilled via vacuum distillation at a reduced pressure and high temperature. According to US OSHA Technical Manual, vulnerable areas within the distillation process include the preheat exchanger (HCl and H_2S), the preheat furnace and bottom exchanger (H_2S and sulfur compounds), the atmospheric tower (H_2S, sulfur compounds, and organic acids), and the overhead (H_2S, HCl, and water vapor) **[4].** The top section of the atmospheric distillation tower is highly vulnerable to corrosion. The most common substances released as a result of a corrosion failure in the distillation tower failure tend to be hydrocarbons, including crude oil and various distilled products.
Hydrotreating	Hydrotreating is a catalytic reaction occurring in the presence of hydrogen at elevated temperature and pressure. It removes objectionable materials from petroleum fractions by selectively reacting these materials with hydrogen in a reactor at relatively high temperatures at moderate pressures. These objectionable materials include, but are not solely limited to, sulfur, nitrogen, olefins, and aromatics **[5].** There are a number of hydrotreating processes used in refineries, one of the most common being desulfurization and denitrogenation. Hydrotreatment units can experience a number of corrosion phenomena.
Catalytic Reforming	The catalytic reformer plant aims to upgrade low octane naphtha to a high octane product that meets "anti-knocking" for blending into motor gasoline pool. As with cracking, catalytic processes have overtaken thermal processes as the process of choice in the industry as the more-effective option. Catalytic reforming unit consists of a series of several reactors (e.g. cracking, polymerization, dehydrogenation). The catalytic reformer may operate at low or high pressures and can be continuous or non-continuous (up to 1000 psig). The reformer is also a major gasoline-producing unit **[6].**
Storage Facilities	Most refineries storage tanks fall into following categories: atmospheric storage, pressure storage, and heated storage. All the storage tank accidents originated in atmospheric storage tanks. All storage tanks are open to the atmosphere, or are maintained at atmospheric pressure by a controlled vapor blanket **[7].** In Groysman's study, 22% of the corrosion failures cited originated in storage facilities **[8].** Potential consequences of atmospheric storage tank failures can be particularly high due to their large capacity. Storage tanks have generally been involved in some of the most severe

	accidents in EU and OECD countries, most often because they have led to sizable fires sometimes requiring a number of days to extinguish. However, the majority of storage tank accidents studied involved predominantly environmental impacts, due to leaks or ruptures at the base of the tank.
Pipeline Transfer	The sheer volume of pipeline network in a refinery makes it inevitable that failure in pipeline transfer due to corrosion is high. Process and utility piping distribute product, process inputs, steam, water, and other process fluids throughout the facility. The size and the construction of pipe depend upon the type of service, pressure, temperature, and nature of the products. Vent, drain, and some connections are provided on piping, as well as provisions for blanking **[4].** For pipeline networks, process conditions are not necessarily the dominant contributor to corrosive conditions. In particular, expose to wet climate, weather, acid rain, and soil may be greater contributors in some cases than internal process conditions. Severe accidents involving pipeline transfer are often associated with loading and unloading involving the transfer of large volumes across the pipeline in a short period of time.

IV. Mitigation of Corrosion on Equipment and Pipeline

(a) External Corrosion

High performance coatings are used to combat external corrosion on surfacial equipment and piping system. While coatings and cathodic protection (CP) are used to combat external corrosion **[9,10]** of buried structures, pipelines and bottom of the tanks. CP is achieved in practice by one of two primary types of CP systems, including sacrificial anode (galvanic anode) CP and impressed-current CP. Sacrificial anode CP utilizes an anode material that is electronegative to the structure to be protected. When connected to the structure, the structure becomes the cathode in the circuit and corrosion is mitigated. Typical sacrificial anode materials for underground structures are zinc and magnesium.

Impressed-current CP utilizes an outside power supply (rectifier) to control the voltage between the structure and the anode (cast iron, graphite, platinum clad, mixed metal oxide, etc.) in such a manner that the structure becomes the cathode in the circuit and corrosion is mitigated.

(b) Internal Corrosion

Internal corrosion is also an electrochemical process; however, CP is not a viable option for mitigation internal corrosion in a pipeline or an equipment. Chemical inhibitor programs are commonly used to mitigate internal corrosion. Corrosion inhibitors and biocides are used. In pipelines which flow fluid having scale forming tendency, scale inhibitors are used to prevent scaling.

(c) Corrosion Under Insulation (CUI)

Corrosion under insulation (CUI) has become one of the serious problem in petroleum refineries, and other plants the world over. Corrosion under insulation is difficult to find because of the insulation cover that masks the problem until it is too late. Moisture combined with oxygen is the largest contributing factor to corrosion. Due to the insulation's ability to trap moisture and hold it against the surface, corrosion-promoting atmospheres rapidly degrade most carbon steel substrates. Insulation is a necessary component of the system and is designed to save energy, control process temperatures, and protect workers from high temperatures. That insulation might be thermal or acoustic. The mechanism of corrosion under insulation involves three requirements: (a) availability of oxygen, (b) high temperature, (c) concentration of dissolved species. According to API Standard 570 **[11]** there are also specific susceptible temperature ranges under which CUI may occur. For carbon steel piping systems, the range is between 25 ºF and 250°F, particularly where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture. Carbon steel piping systems that normally operate in-service above 250°F but that are in intermittent service are also at risk.

It is especially prevalent in the refineries, where steel pipe work is used extensively, and because facilities tend to be located in areas that are fertile for CUI. These include marine and offshore, hot/humid and high rainfall environments. In addition, variable processing conditions create heating and cooling process within the pipe work that encourages a build-up of water within the insulation system.

CUI is insidious. It is hard to see without first removing the insulation and facilities can have long pipe work that need to be manually inspected. It is also a serious problem that can shut plants down often at the cost of millions of dollars per day. In extreme cases, corrosion has been known to trigger catastrophic safety incidents.

NACE International completed a study **[12]** entitled, "The International Measures of Prevention, Application, and Economics of Corrosion Technologies (IMPACT)" and examined the current role of corrosion management in industry and government. The global cost of corrosion is estimated to be US$2.5 trillion per year, which is equivalent to 3.4% of the global Gross Domestic Product (GDP). Of this corrosion cost about $1 trillion annually happens in the oil, gas and petrochemical industries **[13].** Despite the numbers, CUI is widely acknowledged to be one of the most important issues facing plant operators.

V. Prevention of Corrosion Under Insulation (CUI)

The major factor in preventing CUI is to keep liquid from intruding into the insulation. Water decreases the effectiveness of the insulation and leads to corrosion of pipe or equipment. Poor conditions caused by wet insulation can be aggravated by weathering, vibration or abuse from people. There are five factors in preventing CUI: (a) insulation selection; (b) equipment design; (c) protective paints and coatings; (d) weather barriers; and (e) maintenance practices. If an area is subject to spills or high humidity, special consideration must be given to selecting the insulation. Some insulations leave the system less sensitive to defects in weather proofing or paint films because the insulations are nonabsorbent and chemically nonreactive.

Insulations such as calcium silicate, glass fiber and, to some extent, cellular plastic foams absorb and retain liquids and vapors. Additional flashing is required where spills, leaks or drippings may occur, or where washing and hosing are carried out. The only fully nonabsorbent insulation is cellular glass. Cellular glass should be used where corrosive or flammable liquids are present. The proper design of insulation for pressure vessels, tanks and piping includes consideration of the support and connection of the material. Details can be found in a handbook from Midwest Insulation Contractor's Association **[14].** The coating system must protect for long periods against water or corrosives. Highly permeable coatings allow corrosion to start behind the coating even in the absence of breaks or pinholes.

In selecting coatings, consider temperature and abrasion resistance, and a service rating for water (or corrosive-chemical) immersion. It is difficult to visually inspect coatings under insulation to find points that need touching up. Unless corrosion or insulation failure causes reinsulating an entire insulation setup, recoating is done every 10-15 years.

The weather/vapor jacket of the insulation provides the primary barrier to water. This covering is the only part of the system that can be inspected quickly and repaired economically. It must not only keep liquids out but also allow for evaporation of any liquid that manages to get into the insulation system. For weatherproofing, a rating of two perms, measured according to ASTM Standard E 398 **[15],** is acceptable. Also, it should be durable, offer flame-spread resistance, and be economical. The material must be maintained periodically (usually, two to five years) to remain effective.

Further, routine maintenance is needed to catch defects due to deterioration or abuse. If the system is opened in any way for maintenance or inspection, it should be closed promptly after work is completed. Extensive use of a non-breathing metallic jacket is believed to contribute greatly to corrosion of warm equipment. Without a permeable jacket, water is trapped. Water in the insulation reaches a point where it is vaporized. Vapor travels to the jacket and condenses; the cycle repeats itself.

VI. Corrosion Monitoring and Inspection

The monitoring and inspection techniques provide **[16]** a way to measure the effectiveness of the corrosion control systems and provide an early warning when changing conditions may be causing a corrosion problem. The rate of corrosion dictates how long a pipeline or a vessel can be safely operated. Corrosion monitoring techniques can help in several ways:

- by providing an early warning that damaging process conditions exist which may result in a corrosion-induced failure.
- by studying the correlation of changes in process parameters and their effect on system corrosivity.
- by diagnosing a particular corrosion problem, identifying its cause and the rate controlling parameters, such as pressure, temperature, pH, flow rate, etc.
- by evaluating the effectiveness of a corrosion control/prevention technique such as chemical inhibition and the determination of optimal applications.
- by providing management information relating to the maintenance requirements and ongoing condition of a pipeline.

VII. Corrosion Monitoring Techniques

Sampling methods are considered intrusive methods because access to the interior environment is required to obtain a sample. Table 5 lists and describes the characteristics of monitoring techniques commonly used.

Corrosion monitoring devices only provide information about the specific location where they are installed. Therefore, carefully selecting representative locations to monitor internal corrosion is essential in order to collect data that is meaningful. Proper selection requires knowledge of the internal environment and the system design. The categorization of corrosion rates is defined in NACE Standard SP 0775 **[17].**

Table 5: Types of Monitoring Techniques

	Direct	**Indirect**
Intrusive	• Corrosion coupons • Spool pieces • Electric Resistance (ER) probes • Linear Polarization Resistance (LPR) probes • Electrochemical Noise (ECN)	• Hydrogen probes • Water chemistry • Solid analysis • Gas analysis
Non-Intrusive	• Ultrasonic testing (UT) • Electrical Field Mapping (EFM)	• Hydrogen patch probes • Acoustic monitoring

VIII. Inspection of Corrosion under Insulation (CUI)

There are following methods **[18]** used for inspection of corrosion under insulation:

- Profile Radiography
- Ultrasonic Thickness Measurement
- Insulation Removal
- Infrared
- Neutron Backscatter
- Real-Time Radiography

References

1. M.H. Wood, A. L. Vetere Arellano, and L. Van Wijk (2013). Corrosion-related accidents in petroleum refineries, Lessons learned from accidents in EU and OECD countries, JRC Scientific and Policy Reports, European Commission, Joint Research Center, Institute of the Protection and Security of the Citizen, Italy, 2013.
2. J.Coco, Editor (2003). The 100 Largest Losses (1972 – 2001): Large Property Damage Losses in the Hydrocarbon-Chemical Industries. 20th Edition: Marsh Property Risk Consulting 20th Edition. A Publication of Marsh's Risk Consulting Practice.
3. Asset Management, PAS 55:2008, BSI, September 2008.
4. U.S. Occupational Safety and Health Authority. Petroleum refining processes. OSHA Technical Manual. http://www.osha.gov/dts/otm/otm_iv/otm_iv_2.html
5. D.S.J. Jones (2006). An introduction to crude oil and its processing. Chapter 1. Handbook of Petroleum processing. D.S.J. Jones and P.R. Pujado, eds. Springer: Dordrech, The Netherlands, 2006.
6. E. W. Klechka (2002). Pipeline Integrity Management and Corrosion Control**,** Materials Performance, pp. 24 – 27.
7. U.S. Department of Energy (2007). Refinery Outages: Description and Potential Impact on Petroleum Product Prices. Energy Information Administration. Office of Oil and Gas. Washington (DC), USA. ftp://ftp.eia.doe.gov/service/SROOG200701.pdf
8. A. Groysman.2006. Anti-corrosion management, environment and quality at the oil refining industry. http://www.engineers.org.il?_Uploads/1598AntiEnvironIndiaPaper06.pdf.
9. D.S.J. Jones (2006). Support systems common to most refineries. Chapter 13: Handbook of Petroleum processing. D.S.J. Jones and P.R. Pujado, eds. Springer: Dordrech, The Netherlands, 2006.
10. R. Norsworthy (2009). Coatings used in Conjunction with Cathodic Protection – Shielding Vs Non-shielding Pipeline Coatings, published by NACE International, Paper No. 4017.
11. API Standard 570 (2016). Piping Inspection Code - Inspection, Repair, Alteration and Rerating in In-Service Piping Systems, 4th ed., 2016.
12. NACE International Impact Study (2016). "International Measures of Prevention, Application, and Economics of Corrosion Technologies Study", published by NACE International, Houston, March 2016.
13. George F. Hays, PE, Director General, World Corrosion Organization, 2016.
14. Midwest Insulation Contractors Association. "Commercial and Industrial Insulation Standards." Omaha, NE. (1983): Plate No.1-50.
15. ASTM Standard E398, "Standard Test Method for Water Vapor Transmission Rate of Sheet Material Using Dynamic Relative Humidity Measurement". Published in 2013.
16. J.S. Smart and T. Pickthall, (2004). *Internal Corrosion Measurement Enhances Pipeline Integrity*, Pipeline & Gas Journal, October 2004. (www. Pipelineandgasjournal.com).
17. NACE Standard SP0775, Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations, Published by NACE in 2013.
18. G. Kobrin, and B. Moniz, Inspection. maintenance and prevention of corrosion of piping and equipment under thermal insulation. First International Symposium on Process Industry Piping, Orlando, Florida, Sponsored by NACE International and MTI. December 14-17, 1993.