Assets Integrity Management in Oil and Gas Production Facilities Through Corrosion Mitigation and Inspection Strategy: A Case Study of Sarir Oilfield

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***Abstract*—**Sarir oilfield is in North Africa. It has facilities of oil and gas production. The assets of the Sarir oilfield can be divided into five following categories, namely: (i) Well bore and wellheads; (ii) Vessels such as separators, desalters, and gas processing facilities; (iii) Pipelines including all flow lines, trunk lines, and shipping lines; (iv) storage tanks; (v) Other assets such as turbines and compressors, etc. The nature of the petroleum industry recognizes the potential human, environmental and financial consequences that can result from failing to maintain the integrity of wellheads, vessels, tanks, pipelines, and other assets. The importance of effective asset integrity management increases as the industry infrastructure continues to age. The primary objective of assets integrity management (AIM) is to maintain assets in a fit-for-service condition while extending their remaining life in the most reliable, safe, and cost-effective manner. Corrosion management is one of the important aspects of successful asset integrity management. It covers corrosion mitigation, monitoring, inspection, and risk evaluation. External corrosion on pipelines, well bores, buried assets, and bottoms of tanks is controlled with a combination of coatings by cathodic protection, while the external corrosion on surface equipment, wellheads, and storage tanks is controlled by coatings. The periodic cleaning of the pipeline by pigging helps in the prevention of internal corrosion. Further, internal corrosion of pipelines is prevented by chemical treatment and controlled operations. This paper describes the integrity management system used in the Sarir oil field for its oil and gas production facilities based on standard practices of corrosion mitigation and inspection.

***Keywords*—**Assets integrity management, corrosion prevention in oilfield assets, corrosion management in oilfield, corrosion prevention and inspection activities.

I. Introduction

SARIR oilfield contains six gathering centers (GCs). The central processing facilities are at gathering station GC1. The oil and gas separation and storage facilities are at GC1. Sarir oilfield has 368 oil producing wells and 84 observation and abandoned wells. It has a large network of pipelines shown in Table I.

The assets of Sarir oilfield are divided into five categories: (i) Oil wells and wellheads, (ii) Pipelines (shipping lines, trunk lines and flow lines), (iii) Processing equipment (separators, desalters, and gas processing equipment), (iv) Tanks (storage tanks of crude oil, gas and water), (v) Other assets (turbines, compressors, etc.).

TABLE I
Pipelines at Sarir Oilfield

Pipeline	Diameter (inches)	Length (km)	Type of Fluid
Shipping Lines			
Sarir - Tobruk	34	513.6	Crude oil
Messla - Sarir	30	41.2	Crude oil
Sarir - GMMRA	16	90	Gas
Messla – Sarir	20	42.5	Gas
Trunk Lines			
Two Trunk lines	12	23.5	Mixture of crude oil, gas and water
One Trunk line	18	12	
Two Trunk Lines	24	40.5	
Flow Lines	6, 8, and 12	10826.36	Mixture of crude oil, gas and water

The production of oil in Sarir oilfield was started in 1966. Many oil production facilities in Sarir oilfield are mature and reaching the point where structural integrity can be compromised due to the deteriorating condition of fundamental pieces of equipment. The importance of effective asset integrity management increases as the Sarir oilfield infrastructure continues to age. An effective integrity management program anticipates and mitigates or eliminate integrity issues before they lead to incidents or failures.

II. Oil Field Production Environment

Oilfield environments can range from very low rate of corrosion to severely high rates of corrosion [1]. Crude oil, by itself, is not corrosive at normal production temperatures without having the dissolved gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S). The most of the corrosion problems in oil and gas production facilities are due to CO_2 and H_2S gases, in combination with water. Other problems include microbiological activity and the solids accumulation. The mechanisms of CO_2 corrosion are generally well defined [2]-[4] The status of corrosion inside a storage tank, processing vessel or a pipeline becomes complicated when CO_2 acts in combination with H_2S, deposited solids, and other environments. H_2S is not corrosive by itself but it can be highly corrosive in presence of water. In some cases, it forms a

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protective sulfide scale that prevents corrosion. Microorganisms can attach to walls of pipes and vessels and cause corrosion damage. The presence of formation sand and other solids can cause problems with under-deposit corrosion, if stagnant. The formation sand can erode the pipeline/vessel internally. The severity of corrosion depends on the flow rate of the fluid.

Oxygen is corrosive but not found in oil reservoirs. The measures are taken to ensure that no oxygen enters the production facilities; however, it has been found that a few parts per million (ppm) of oxygen will enter the pipelines, which is greatly exacerbating corrosion problems.

External corrosion is one of the major factors contributing to the deterioration of buried pipelines. It increases the risk of failure. The soil properties such as resistivity, pH, and presence of sulfate reducing bacteria affect the aggrasiveness of soil towards external corrosion on buried pipelines. The effect of these properties on pipeline is discussed elsewhere [5]. Buried pipeline encounters soils that have varying compositions. Dissimilar soils can affect a buried pipeline. The problems in oil and gas production facilities are normally similar to those found in the pipeline industry. The flow lines are shorter and smaller in diameter. Their economic impact on the total cost of production is limited. Atmospheric corrosion of structures and vessels is a problem for offshore fields and those operating near marine environments.

III. Standard Method in Asset Management

The effective control and governance of assets are essential to realize value through managing risk and opportunity. The assets management system is defined in International Standard ISO 55000 [6].

The Integrity Management Program (IMP) forms part of a comprehensive assets management system operating alongside safety and environmental programs. The operator shall establish, implement and maintain a document IMP and routinely review and improve its adequacy.

The effective implementation of the following aspects determines the success of life cycle AIM (assts integrity management): (a) feasibility, (b) design, (d) procurement, (d) fabrication, (e) modification, (f) transportation and storage, (g) pre-commissioning and commissioning, (h) handover, (i) operation and maintenance, (j) suspension/abandonment. This paper limits the discussion only on corrosion management aspects. The corrosion management plan of oilfield facilities can be designed by understanding corrosion environment in the oil and gas production facilities.

A. Wellhead Integrity Management

Well integrity policy defines commitments to safeguard health, safety and environment. It also safeguards assets. Well integrity refers to maintaining full control of fluids within a well. The unintended fluid movement or loss of containment to the environment is also stopped through maintaining wellhead integrity. The purpose of a wellhead is to provide pressure seals for the casing strings and suspension points. The most common failure mechanisms found during inspections are as follows:

a) *Corrosion and erosion:* Corrosion on bare metal from the environment and weather can be prevented by external coatings and paint
b) *Failure of seals and gaskets:* The monitoring of pressure and regular visual inspection are key steps to ensure the integrity of the wellhead seals is maintained. The elastomer seals are prone to long term deterioration and must be replaced once the stated design life has been exceeded.
c) *Formation changes* due to the quality of the fluid being produced tends to deteriorate as the field life increases. The results of regular production fluid analysis should be determined so that the structural integrity risks associated with each well can be prioritized and the well maintenance program followed accordingly.

B. Pipeline Integrity Management

The pipeline integrity management addresses the operator's approach to the following elements:

(a) Life cycle phases for integrity management. Integrity is applied through the entire life cycle of pipeline elements.
(b) Primary integrity management process - As part of the continuous improvement process, the inputs of the following elements are routinely updated: (i) risk assessment (threat, consequence, probability, critical consequence area (CCA)), (ii) inspection, (iii) integrity assessment, (iv) mitigation activity, (v) performance measurement and improvement, (vi) data management (data acquisition, review and integration).

Understanding the pipeline's integrity and threats in the context of the surrounding environment is key to making informed integrity management decisions. 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.

a) Failure assessment plan
b) Emergency response plan
c) Remaining life assessment plan

The external environment on pipeline materials (pipe, welds, coatings, etc.) and the characteristics of fluids flowing in the pipeline are the causes of pipeline degradation. Corrosion is the most prevalent threat to a pipeline. It is a time-dependent phenomenon. There are two types of corrosion: (i) external corrosion, and (ii) internal corrosion. External corrosion is a function of the interaction between the buried pipeline and the soil that surrounds it. The aggressiveness of soil towards steel is affected [7] by soil properties such as resistivity, pH, and presence of sulfate reducing bacteria. Dissimilar soils can affect a buried pipeline, as they will encounter soils that have varying compositions.

Internal corrosion can be caused [8] by components such as water, carbon dioxide (CO_2), and hydrogen sulfide (H_2S). It can be aggravated by microbiological activity. Crude oils in pipeline are always accompanied by traces of water and varying amounts of dissolved acid gases such as CO_2 and H_2S. Presence of CO_2, H_2S, free water, suspended solids (sand) and bacteria can cause corrosion problems in oil and gas pipelines. Temperature, water chemistry, flow velocity are the parameters which also influence internal corrosion.

The other factors, which also contribute to the pipeline's integrity are soil conditions, temperature, stresses (residual and others), pipeline pressure and cycling loading effects.

1. Mitigation of Corrosion on Pipeline

a. External Corrosion

The pipeline coatings and cathodic protection (CP) are used to combat external corrosion [9], [10] of buried pipelines. CP is achieved in practice by installation of CP system. There are two primary types CP systems: (a) sacrificial anode (galvanic anode) CP, and (b) impressed-current CP. Sacrificial anode CP utilizes an anode material that electronegative to the pipe. Typical sacrificial anode materials used in the industry for underground pipelines are zinc and magnesium. Impressed current CP system utilizes an outside power supply (rectifier) to control the voltage between the anode and the pipe. The most common materials of anode are graphite, mixed metal oxide, cast iron, platinum clad, etc.

b. Internal Corrosion

Internal corrosion is an electrochemical process. Chemical inhibitor programs are commonly used to mitigate internal corrosion [11]. Corrosion inhibitors and biocides are used to mitigate internal corrosion. In pipelines which flow fluid having scale forming tendency, scale inhibitors are used to prevent scaling. Periodical cleaning by pigging is also performed in pipelines to prevent internal corrosion.

IV. Corrosion Monitoring and Inspection

The corrosion monitoring and inspection techniques provide [11] a way to determine the effectiveness of the corrosion control systems. The determination of corrosivity of process stream by using probes is called monitoring. Corrosion monitoring "probes" are mechanical, electrical, or electrochemical devices. The corrosion monitoring techniques are as follows:

- Weight loss coupons
- Electrical resistance
- Linear polarization
- Hydrogen penetration
- Galvanic current

A wide variety of corrosion inspection techniques exists, including:

- Ultrasonic testing
- Radiography
- Thermography
- Eddy current/magnetic flux
- Intelligent pigs

Direct External Corrosion Assessment

External corrosion direct assessment (ECDA) refers [12] to a structured process. It intended to improve safety by assessing the impact of external corrosion on pipeline. ECDA is done in four steps:

(a) The "Pre-Assessment" step involves the collection and evaluation of historical data and pipeline characteristics.
(b) The "Indirect Inspection" step involves a combination of two or more above ground survey techniques. The more common above ground survey techniques are (i) close interval potential survey (CIPS), (ii) alternating current voltage gradient (ACVG), (iii) direct current voltage gradient (DCVG), (iv) AC attenuation for the identification of areas with corrosion activities or coating faults.
(c) The "Direct Examination" step covers the selection of sites to be excavated and the physical identification of defects requiring repair or replacement.
(d) The "Post Assessment" step evaluates the previous three steps of the ECDA process and establishes a future assessment schedule.

In-Line Inspection of Pipelines

The degradation processes occurring in a pipeline system such as corrosion, erosion, cracks propagation, etc. lead to the appearance of various physical and geometrical defects. These defects affect the general characteristics of system operability. It is necessary to know the size of these defects. This is done [13] by regular in-line inspection (ILI) during which defect parameters are determined. Inspection results serve as the basis for assessing pipeline residual life, and selecting the most efficient type of maintenance. Information obtained during an inspection consists of data on the pipeline material metallurgical anomalies, other types of defects, their location, orientation along the longitudinal axis and across the pipe circumference (perimeter), as well as their dimensions (length, depth, width).

Intelligent Pigging is an inspection technique. The inspection probe used intelligent pigging is referred to as a "smart" pig. After the pigging run has been completed, the positional data are combined with the pipeline evaluation data (metal loss corrosion, cracks, etc.) to provide a location-specific defect map and characterization. This is used to judge the severity of the defect and help to locate and repair the defect quickly without having to dig up excessive amounts of pipeline.

Most common measurement instruments used in ILI of oil pipelines are a magnetic flux leakage inspection pig and an ultrasonic inspection pig. The method of ILI of pipelines is described in NACE standard RP 0102 [13].

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