CONTROL & MONITORING PETROLEUM PIPELINES CORROSION

By

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A thesis submitted for fulfillment of the requirements
for degree of M.sc.

2004
"سَأَلَّكَ ﷲ ﻋَنِ ﺍﻟْﻤَاردَ ﻓَأَسْأَلُكَ ﻋَنِ ﺍﻟْﻴَﺤْرَاءَ" ؛

الآية (25)
سورة الحديد
Dedication

My Mother

Adil

To my sister and my friends
without whose help support and encouragement
this work could not be possible
ACKNOWLEDGMENTS

I would like to express my sincere gratitude to Dr. Osama Abd AlHamid for his supervision and guidance.

I would like to express my sincere gratitude with many thanks to Dr/ Colin Agrent for his continuous active help and support during this study.

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Finally I would thank my family for love, support and prayers.
Corrosion is the deterioration of the metal as a result of its reaction with the surrounding environment. The corrosion in the pipelines that carry petroleum products is considered as the main problem facing petroleum products pipelines which is as a result of its reaction with environment that include soil, its salts and water. The corrosion resulting from this reaction is called external corrosion which is more dangerous, therefore it will be considered more than internal corrosion that occur between pipe internal surface and petroleum product compounds.

The present study aimed to investigate the effect of different environments and different kinds of soil through which pipeline buried extends from Shagara (Khartoum) to Port Sudan, and it is also aimed at the detection of the effectiveness of coating and cathodic protection system that it has followed.

Also in this study chemical analysis has been done to examine the sorts of soil surrounding the pipeline and its chemical properties. These properties include soluble salts, degree of acidity, soil resistivity and relative humidity, and have followed the pipe inspection that has been carried out by Pipeline Integrity Inspection Company (PII) 2002-2003, and on the view of study it can be evaluated. Through this study the obtained results show that the soil in Khartoum, Shendi and Atbara areas is non corrosive because of the low soluble salts and also its corrosion resistance is very high, and is dry most of year months, moreover it is an alkaline soil.

The inspection results indicate that the corrosion is spreading extensively in those areas because cathodic protection is poor. On the other hand corrosion is very weak in Port-Sudan area, although the soil in this area has a very low soil resistivity, very high insoluble salts, and high relative humidity but cathodic protection is extensively used in this area. So the study accessed that most corrosion occur under the tape, that means corrosion is not as a result of coating defect surrounding the pipe which indicate that corrosion is not connected to the circumstance surrounding the pipe, but it may be as a result of the poor protection due to the less number of the cathodic protection stations, or defects in the type of pipes material that is was made of, manufacturing process, or coating process methods. A worthy study and searching should be carried for this phenomenon. The study also recommended some methods used on control and monitoring of pipeline corrosion.
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Chapter One
Introduction

1.1 Introduction:
Frequently, humans try to develop and search in all methods of manufacturing problems that affect progress and development of manufacturing. Hence they try to find proper solutions to those obstacles, by more study and search in the causes and its consist, also trying to find methods to avoid, either by finding treatments or by establishing new techniques. To all that would like to make a worthy study and searching a phenomenon that trouble the industrial development by wasting time to administrate it plus economic exhaustion which causes in the way of fending off or decreasing. The phenomenon is the chemical corrosion that happens to the industrial establishments as a result of many factors.

Metal corrosion is considered as one of the problems that face the industrial progress, and it is known as physical establishment collapse as a result of its reaction with the surrounding environment.

1.2 Corrosion
Most people are familiar with rust because normally it attacks cars, tools and bicycles... In fact any thing made of iron and steel is subject to rust if it is left unprotected in moist environment. Crystalline elemental iron, which is the basis of cast iron & steel, is not stable in nature but always generated in the steel making process. When it is exposed to a wet, oxygen rich environment a spontaneous reaction occurs on the surface where crystalline iron reverts to an oxide, or some other stable form, which is called the basis of corrosion. Corrosion engineering is the application of science and art to prevent or control corrosion damage economically and safely. Corrosion science is the study of the chemical and metallurgical processes that occur during corrosion. Ideally, science should be married to engineering so as to invent new and better methods of prevention and apply existing methods more intelligently and effectively.

1.3 Pipeline Corrosion
Many metals installation, such as pipeline (buried one), utility cables.... etc, are subject to the rust which is the most type occurring. Generally speaking, corrosion of underground pipelines is not so common as in the atmosphere or underwater. More factors enter into underground corrosion than into atmospheric or underwater corrosion. For this reason, the problem of investigating the deterioration of metals underground is more complex than in the other media. The most severe corrosion occurs in low resistivity soils, such as wet clay and in very acidic soil.

This research focuses mainly on loss of metal from the pipe. Any loss of pipe wall thickness variably, in means a reduction of structural integrity and hence an increase in risk of failure. Differences in metal properties can also create anodes and cathodes on the pipe surface. For example when iron & steel are electrically connected together in soil the steel will tend to be anodic and will corrode while iron will be cathodic and will not corrode. Carbon in
the backfill, behaves like a metal, and will work as cathodic to both iron & steel. Carbon in the form of coke in the backfill creates a severe corrosion cell for iron & steel. Corrosion current does not necessarily occur naturally, any DC current flow on to a pipeline can swamp the natural flow of current in a corrosion cell, the current leave the pipe and flows back into the soil, the pipe will be anodic and will corrode at a rate dictated by the magnitude of the current flow.

Stressed iron or steel tends to be anodic so corrosion can be concentrated in areas of high stress such as bolts, or on pipe sections subject to bending loads. Stress creates the stress corrosion cracks. There are many forms of stress corrosion attack metal in soil. All these forms of corrosion can be prevented by a protective coating, providing its sticks to the pipe and prevents contact between the pipe and soil and also to keep the current flowing all through the buried pipe between the sacrificed anode and the pipe as cathode connected to a power source. This technique normally used for long buried pipeline, is called cathodic protection technique.

Repair methods used to monitor and fix corrosion in pipeline is a very expensive technology, costing too much because of the quantity of products lost due to pipe burst and the cost of repair.

This study tries to find out some solutions to this dangerous phenomenon, which does not lead to fend off, but to decrease its progress, and identify causes that lead it to happen. Pipelines through which petroleum products are transported were chosen in this study.

1.4 Objectives
1.4.1 Main Objective:
The aim of this study is to evaluate metal loss features for an old buried pipeline (24 years old) run from Port Sudan to Shagara.

And also to determine a number of methods that help on monitoring and controlling pipeline corrosion.

1.4.2 Specific Objective:
The Specific objective of this study is to investigate the extent of the corrosion action at various environmental conditions, and various types of soil in Sudan, occurring along pipeline, and the effectiveness of coating and applied cathodic protection system, in reducing corrosion under different kinds of soil condition.
Chapter Two

Literature Review

2.1 Costs of Corrosion

The economic costs of corrosion in the United States of America alone have been estimated from $8 billion to $126 billion per year. The most comprehensive study on the economic cost of corrosion in the United States estimated an annual cost of $70 billion. While the Department of Commerce
has stated that corrosion would cost the United States an estimated $126 billion in 1982. These figures are somewhat misleading because zero corrosion assumed as the baseline is unattainable. Some measures, while reducing corrosion, will cost more than the parts or equipment protected. A perhaps more realistic annual $30 billion has been suggested for the savings that could result if all economically useful measures were taken to prevent or minimize corrosion. The figures given above are only the direct economic costs of corrosion. The indirect costs resulting from actual or possible corrosion are more difficult to evaluate but are probably even greater.

Some more important sources of indirect costs are summarized as follows:

- **Plant Downtime:**
  Parts and labor to replace corroded equipment are often minor compared to the loss of production while the plant is inoperable during repairs.

- **Loss of Product:**
  Leaking containers, tanks, and pipelines result in significant losses in product, which have a high cost. These leaks and spills have a corresponding hazardous effect on the surrounding environment and the populace.

- **Loss of Efficiency:**
  Accumulated corrosion products on heat exchanger tubing and pipelines decrease the efficiency of heat transfer and reduce the pumping capacity, respectively.

- **Contamination:**
  Soluble corrosion products can spoil chemical preparations of soap, dyes, and pharmaceuticals, among others.

- **Over design:**
  In the absence of adequate corrosion rate information, over design is required to ensure reasonable service life, resulting in wasted resources, and greater power requirements for moving parts.

### 2.2 Corrosion

Corrosion comes from the Latin word corrodere, meaning “Gnaw to pieces”. Corrosion is the destructive result of chemical reaction between a metal alloy and its environment. Metal atoms in nature are present in chemical compounds (i.e., minerals). The same amounts of energy needed to extract metals from their minerals are emitted during the chemical reaction that produces corrosion. Corrosion returns the metal to its combined state in chemical compounds that are similar or even identical to the minerals from which the metals were extracted. Thus corrosion has been called extractive metallurgy, and also can be defined as the reaction of a metallic material with its environment. The products of this reaction may be solid, liquid or aqueous. Both physical and chemical nature of the products is frequently
influencing the subsequent rate of reaction. The corrosion of metals represents a terrible waste of both natural resources and money.

The present knowledge of the corrosive or non corrosive character of any particular soil is based largely upon practical experience as to the rate at which metal buried in the soil is attacked. There is still need of study, such as that started in 1922 by the NBS, with the aid of an Advisory Committee of manufacturers and users of pipe.

It is necessary to remember that the choice of metal depends on many factors including its corrosion behaviors:

1. Corrosion resistance
2. Availability
3. Strength
4. Fabricability
5. Appearance

The corrosion resistance depends on the following factors:

1. Electrochemical
2. Thermodynamic
3. Physical/chemical properties
4. Metallurgical

2.3 Thermodynamic Aspects

Thermodynamic and electrochemistry are of great importance for understanding and controlling corrosion. Thermodynamic (which is the science of energy changes) gives an understanding of the energy changes involves in the electrochemical reactions of corrosion. These energy changes provide the driving force and control the spontaneous direction for a chemical reaction. Thus thermodynamics show how conditions may adjust to make corrosion impossible. Thermodynamic is very important to understanding of the electrochemistry corrosion.

2.3.1 Corrosion Reactions:

Oxidation of iron releases electrons; react with water to produce hydroxide, iron oxidation, called an anodic reaction because it takes place at anodes. Reduction of water to hydroxide occurs at cathodes, metal loss or corrosion only occurs at the anode, not at the cathode.

The release of electrons must balance an electric currents flow between anode and cathode called corrosion current, and the combination between anode and cathodes and electrolyte called a corrosion cell. Current within the corrosion cell flows from the anode through the soil to the cathode and back through the pipe to the anode to complete the circuit. Wet soils with a high soluble salt content have a low electrical resistivity where current flow creating continuous corrosion.

\[
\begin{align*}
\text{Fe} & \rightarrow \text{Fe}^{+2} + 2e \quad \text{Oxidation (anodic reaction)} \quad \text{e.q (1)} \\
2H^+ + 2e & \rightarrow \text{H}_2 \quad \text{Reduction (Cathodic reaction)} \quad \text{e.q (2)}
\end{align*}
\]

An oxidation or anodic reaction is indicated by an increase in valency or production of electrons. A decrease in valance charge or the consumption of electrons signifies a reduction or cathodic reaction.

Equation (1) & (2) are partial reactions both most occur simultaneously and at the same rate on the metal surface.
The basic anodic and cathodic corrosion reactions for iron in wet, oxygenated environment are:

\[ \text{Fe} \rightarrow \text{Fe}^{+2} + 2e^+ \]

\[ \frac{1}{2} \text{O}_2 + \text{H}_2\text{O} + 2e \rightarrow 2(\text{OH})^- \quad \text{e.q (3)} \]

Further reaction can occur to form hydrated iron oxides:

\[ \text{Fe}^{+2} + 2\text{OH}^- \rightarrow \text{Fe} (\text{OH})_2 \quad \text{e.q (4)} \]

\[ 2\text{Fe} (\text{OH})_2 + \text{H}_2\text{O} + \text{O}_2 \rightarrow 2\text{Fe} (\text{OH})_3 \quad \text{e.q (5)} \]

The final product is \( \text{Fe} (\text{OH})_3 \).

The nature of oxide film formed on the surface of the metal by the corrosion is the familiar rust. Reaction can influence the long-term corrosion rate 4.

**Corrosion Rate:**

Corrosion rates have been expressed in a variety of ways in the literature, as listed in table (2.3). The first one is weight loss in grams or milligrams and percent weight change of matter exposure to corrosion environment are poor ways of expressing resistance. The next group of expressions is merely variations of the generalized expression of weight loss per unit area per unit time. Milligram per square decimeter per day (mdd) is commonly used in English & American corrosion literature. However, they all have a serious disadvantage they do not express corrosion resistance in the form of penetration, or thinning of a structural piece, can be directly used to predict the life of a given component. The next four expressions, which include inches penetration per year, inches penetration per month, millimeter penetration per year, mils penetration per year (mpy), express corrosion resistance directly in terms of penetration 5.

Recent advancements in the accuracy and resolution of in-line-inspection tools have made it possible to estimate corrosion rates and future corrosion severity on pipelines with a reasonable degree of confidence. This allows pipeline operators to identify specific areas where corrosion is most active and predict what the probable future severity of that corrosion will be. From the standpoint of convenience, mils per year are preferred, since the corrosion rate of practically useful materials varies between approximately, 1 and 200 mpy. Thus using this expression it is possible to present corrosion data using small whole numbers and avoiding decimals. It is obvious that the expressions inches per year and inches per month will involve decimal points & numerous naught which frequently lead to errors when transcribing data, for the reasons noted above, the expression mpy is the most desirable way of expressing corrosion rates. This expression is readily calculated from the weight loss of the metal specimen during the corrosion test by the formula given by:
\[ \text{mpy} = \frac{534W}{\text{DAT}} \]

Where:
W: weight loss mg
D: density of specimen
A: area of specimen square inch
T: exposure times, hr.

Table (2.3) Show Comparison of Corrosion-Rate

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<td>Weight Loss, or mg Percent weight change</td>
<td>Poor-Sample shape and exposure time influence results.</td>
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<td>Milligram per square decimeter per day (mdd). Grams per square decimeter per day. Grams per square centimeter per hour. Grams per square meter per hour. Grams per square inch per hour. Moles per square centimeter per hour.</td>
<td>Good but expressions do not give penetration rates.</td>
</tr>
<tr>
<td>Inches per Year. Inches per Month. Millimeter per Year.</td>
<td>Better-expressions give penetration rates.</td>
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<tr>
<td>Mils* per Year (mpy)</td>
<td>Best-expresses penetration without decimals large numbers.</td>
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*1 mil = 0.001 inch

External & internal corrosion rate can be calculated for an old pipeline if metal loss data available for a certain period, while it is very difficult to monitor or say it is active or not unless two runs of inspection carried out to compare the data.

In theory, determining corrosion rates from multiple In-line inspections (ILI) data sets should be relatively simple. In-line inspections provide the location and size of corrosion defects, and corrosion rates can then be calculated from the change in defect sizes between inspections. In practice, however, there are several difficulties that need to be overcome.

The first problem arises when attempting to accurately match defects from one inspection to the next. Odometer slippage; orientation differences; change in corrosion size and shape; and different inspection tools with varying accuracy and sensitivity all combine to make the matching quite complicated. Computer technology has made the matching of large numbers
of defects a manageable task. This software can identify and correlate corrosion patterns between ILI data sets, accounting for difference in orientation and defect characteristics.

A second problem that needs to be overcome when predicting corrosion growth involves accounting for the error associated with ILI tools, if ILI tools were perfectly accurate, determining corrosion rates would be quite straightforward.

2.4 Corrosion Forms:

It is convenient to classify corrosion by the appearance of the corroded metal. Each form can be identified by mere visual observation, in most cases the naked eye is sufficient, but sometimes magnification is helpful or required. Some of the eight forms of corrosion are unique, but all of them are more or less interrelated.

The eight forms are:

2.4.1 Uniform Attack:

Uniform attack is the most common form of corrosion characterized by a chemical or electrochemical reaction, which proceeds uniformly over the entire exposed surface or over a large area. The corrosive environment must have the same access to all parts of the metal surface, and the metal itself must be metallurgical & compositionally uniform. Atmospheric corrosion is probably the example of it.

2.4.2. Galvanic or Two Metals Corrosion:

A potential difference usually exists between two dissimilar metals when they are immersed in a corrosive or conductive solution. If these metals are placed in contact this potential difference produces electrons flow between them, corrosion of less corrosion resistant metal is usually increased and attack of more resistant material is decreased, as compared with the behavior of these metals when they are not in contact. The less resistant metal becomes anodic and the more resistant metal cathodic, usually the cathodic does not corrode at all. It is electrochemical corrosion, the driving force for current and corrosion is the potential developed between the two metals. Dry-cell-battery is the good example of this point.

2.4.3 Crevice Corrosion:

Intense localized corrosion frequently occurs within crevices and other shielded areas on metal surfaces exposed to corrosives. This type of attack solution is usually associated with small volumes of stagnant on caused by holes, gasket surface, lap joints, surface deposits, and crevices under bolt and riverheads. Examples of deposits, which may produce crevice corrosion, are sand, dirt products, and other solids.

2.4.4 Pitting:

Pitting is a form extremely localized by attack that results in holes in the metals. Pits are sometimes isolated or also together that they look like a rough surface. Generally a pit may be described as cavity or hole, pitting that have the most restructure and insidious forms of corrosion. It causes equipment to fail because of perforation with only a small percent weight loss.
of the entire structure. It is often difficult to detect pits because of their small size and because the pits are often covered with corrosion products. Also it is difficult to measure quantitative and compares the extent of pitting because of the varying depths and numbers of pits that may occur under identical conditions.

2.4.5 Intergranular Corrosion:

When a metal solidifies during casting the atoms which are randomly distributed in liquid state, arrange them selves in a crystalline array. However, this ordering usually begins at many points in liquid as these blocks of crystals or grains meet. There is mismatch at this boundary. When the metal has solidified and cooled, there will be numerous regions of mismatch between each grain. These regions are called grain boundaries, which are high-energy areas and are more active chemically. Grain boundary affects little or no consequence in most application or uses of metals. If a metal corrodes uniform attack results since grain boundaries are usually only slightly more reactive than matrix. However under certain conditions, grain interfaces are very reactive and intergranular corrosion results. Intergranular corrosion can be caused by impurities in the grain boundaries.

2.4.6 Selective Leaching:

Selective leaching is the removal of one element from a solid alloy by corrosion processes.

2.4.7 Erosion Corrosion:

Erosion Corrosion is the acceleration or increase in the rate of deterioration or attack on a metal because of relative movement between a corrosive fluid and the metal surface. Generally, this is quite rapid and mechanical effect. Metal is removed from the surface as dissolved ions, or it forms solid corrosion product. Erosion corrosion is characterized in appearance by grooves, gullies waves rounded holes. Most metals and alloys are susceptible to erosion corrosion damage. Many depend upon the development of a surface film of some sort for resistance to corrosion. Erosion corrosion caused by many types of corrosive media such as gases, aqueous solution, organic system.

2.4.8 Stress Corrosion:

Stress corrosion cracking (SCC) is the brittle failure at relatively low constant tensile stress of an alloy exposed to corrosive environment. SCC was apparently first reported as the so-called season cracking. It has been thought that three conditions must be present simultaneously to produce SCC: a critical environment, a susceptible alloy, and some component of tensile stress. Environment species are often specific to the alloy system and may not have an effect on other alloys of different types, for example hot aqueous chloride solutions readily crack stainless steels, but do not have the same effect on carbon steel.
2.5 Pipelines Corrosion

The potential for pipeline failure caused either directly or indirectly by corrosion is perhaps the most familiar hazard associated with steel pipelines. Corrosion, as it is used in this study, focused mainly on a loss of metals from pipe. Manufactured metals have a natural tendency to revert to their original mineral form, while this is usually very slow process; it requires the injection of energy. Corrosion is concern because any loss of pipe wall thickness increases in the risk of failure.

The corrosion index consists of the three categories 2:
1-Atmospheric corrosion: this is weighted as 20% of the total corrosion risk.
2-Internal corrosion: this is weighted as 20% of the total corrosion risk.
3-Buried metal corrosion: this is weighted as 60% of the total corrosion risk.

2.5.1 Atmospheric Corrosion:

Atmospheric corrosion is basically a chemical change in the pipe material resulting from the material’s interaction with the atmosphere. Most commonly this interaction causes the oxidation of metal.

Atmospheric corrosion in air is confined to temperatures and condition resulting from exposure to the natural ambient environment, which contains variable amount of water from rain & splashing. Dissolved oxygen is more readily transported through a thin layer of surface water than through bulk water during complete immersion. Thus corrosion in the splash zone above water is higher than in full immersion, periodic washing by rain water less severe than those of continuous splashing. The normal mode of atmospheric corrosion is general uniform attack.

Atmospheric parameters affecting corrosion:

1. Humidity:

Thin layer of condensed water deposits on the surface provide the electrolyte for electrochemical corrosion. Humidity is not sufficient, even in very humid environment; corrosion of uncontaminated surfaces is often relatively low in unpolluted atmospheres. The rusting set up by the settlement of saline partials can only occur if the humidity of the air is sufficiently high to render stable a liquid film. Saturated of sodium chloride is in equilibrium with air of 78% R.H in BUKOWIECKI’s experiment. Steel caring sodium chloride particles became strongly rusted at 80% R.H, and remained bright at 60% and at 70% the salt particles became brown and there was perceptible attack on the metal. Strongly hygroscopic salts can set up rusting even in relatively dry air:

<table>
<thead>
<tr>
<th>Salt</th>
<th>ZnCl</th>
<th>LiCl</th>
<th>MgCl2</th>
<th>CaCl2</th>
</tr>
</thead>
<tbody>
<tr>
<td>R.H%</td>
<td>10</td>
<td>15</td>
<td>32</td>
<td>32.3</td>
</tr>
</tbody>
</table>

2. Pollutants:

Pollutant or other atmospheric contaminates in atmospheric corrosion by enhancing the electrolytic properties and stability of water film that condense from the atmosphere. Sulfur dioxide SO2 industrial pollutant which forms sulfuric acid when dissolved in the surface films in presence of SO2 the film is not protective and weight loss increases linearly with time. Thus pollutants can provide dissolved solutions in the surface water film; SO2, NO2, Cl2 and F are prime example. In atmospheres containing 0.01% SO2, the corrosion rate of carbon steel increased rapidly above critical humidity of 60%.

It has been mentioned that the rate of corrosion of iron & steel is faster when in contact with water containing sodium chloride or other salts. This because of the conductivity of water increases due to increase in the number
of ions present. The more concentrated salt solution is the lower solubility of oxygen in the water. Consequently the rate of corrosion of steel in a salt solution is a maximum at a concentration of about 3% NaCl.

3. Temperature:

Temperature has a variable effect on atmospheric corrosion; ambient atmospheric temperatures keep corrosion rate relatively low but may enhance the condensation of an aqueous surface film to increase corrosion, high temperature dry the surface and reduce corrosion. As a result shaded surfaces often corrode more rapidly than those exposed to direct sunlight. Finally a combination of high humidity, high average temperature and the presence of industrial pollutants or air entrained sea salt increase atmospheric corrosion rates.

2.5.2 Internal Corrosion:

Internal corrosion in refined product lines is most usually associated with water separation from the product. This can occur as water carry over from the base of a ship’s tank or a storage tank or as progressive separation of water contained within the product. Internal corrosion is caused by a reaction between the inside pipe wall and the product being transported, such corrosive activity may not be the result of an impurity in the product stream.

Figure 2.5 show internal corrosion

Common corrosion promoting substances sometime found in natural gas include CO2, Cl2, H2S, organic acids, oxygen, free water, solid precipitates and sulfur. Internal corrosion of oil or gas production systems is termed sweet or sour depending on the hydrogen sulphide content: 7

Sweet Corrosion

The morphology of sweet corrosion is typically general attack or localized pitting. The location of attack may be controlled by flow conditions and distribution of water and the shape of corrosion pits may also be influenced by local flow condition, especially turbulence.

Sweet corrosion is an acid corrosion process occurs in the presence of free water, which has been made acidic by carbon dioxide from the products. Free water may arise due to:

1/Carry over water from separator; this creates corrosive conditions at pipeline inlet.
Condensation of water from the gas phase as the product in the pipeline cools. This may produce a thin water film over the surface of the pipe but depending on the flow system.

Separation of water entrained in the oil phase as emulsion.

The factors that influence the rate of internal corrosion attack are:

1. Water content.
2. Carbon dioxide content.
3. Product temperature.
4. Water PH.
5. Flow system.
6. Hydrogen sulphide content.

**Sour Corrosion:**

The sour corrosion has been defined by NACE as 0.0003 MPa hydrogen sulphide. Below this partial pressure of hydrogen sulphide the operating conditions are called sweet, at higher partial pressures of hydrogen sulphide is called sour. In sour conditions new corrosion mechanism becomes important and these are concerned with the various forms of hydrogen cracking. Times to failure from pitting corrosion for carbon steel pipelines are measured in years, months, but potential times to failure from sour service cracking may be measured in days or hours. The carbon steel pipelines can be designed to the sour service resistant and when this has been achieved the principle failure risk may revert to pitting corrosion.

The corrosion mechanisms peculiar to sour service conditions are:

**Hydrogen induced cracking (HIC)**

A wet hydrogen sulphide environment is necessary for HIC occurring. The lowest partial pressure of hydrogen sulphide at which HIC has been reported in practice is approximately 0.0003 MPa. Above this partial pressure of hydrogen sulphide there is a risk of HIC occurring irrespective of the total product pressure in the system since HIC is not dependent on operating stress. No lower limit is specified for the free water content of sour oil or gas systems in assessing HIC risk. HIC will not occur in a system that maintained continuously dry but short duration excursions from dryness are significant. In susceptible materials HIC failures can occur within days.

**Stress oriented hydrogen induced cracking (SOHIC)**

Stress oriented hydrogen induced cracking SOHIC occur as small, staggered cracks in a characteristic "ladder-like" array. This array is typically aligned perpendicular to the principal stress, which may be the operating stress or a residual stress. SOHIC is thought to be sulphide stress cracking which is caused by a combination of external stress and local straining around. Soft zone cracking (SZC) is similar to SOHIC but occurs specifically in softened heat affected zones (HAZ) of welds in rolled plate steel. The susceptibility of such weld regions to this type of cracking is thought to arise because of a combination of micro structural effects caused by the temperature cycling during welding and local softening in the intercritical temperature HAZ. This results in strains within a narrow zone, which may approach, or even exceed the yield strain.
Sulphide stress corrosion cracking (SSCC)

Sulphide stress corrosion cracking SSCC occurs in high strength steels in wet, sour gas or oil service. As with HIC it occurs when atomic hydrogen diffuses into a metal, but for SSCC the hydrogen remains in solid solution in the crystal lattice. This solid solution of hydrogen reduces the ductility and deformability of metal and the effect is called hydrogen embrittlement. Embrittled steel readily cracks under an applied tensile load so for SSCC to occur there must be an externally applied stress except in welded steel where residual stresses can contribute to the initiation and growth of SSCC. The development of SSCC cracks can be very rapid and has been known to progress to failure within hours.

2.5.3 External Corrosion
Buried Metal Corrosion:

Unprotected iron & steel will corrode in soil if water is present, the rate of corrosion reaction may be influenced by number of factors:
1. The water content is high.
2. The soluble salts content is high.
3. The soil is acidic with low PH.
4. The soil has low oxygen content.

Steel in wet soil will corrode, the corrosion may occur uniformly over the surface or as localized corrosion pits. In either case the basic corrosion reaction is the same corrosion occurs at the steel surface where it is in contact with the wet environment. As a result of corrosion reaction a potential develops the metal–water interface. This potential can be measured using a suitable reference electrodes and the potential measured is good indicator of the level of corrosion activity.

Soil Corrosion:

Soil is the most environments to be considered. Here the water is held in a great complexity of ways and contains a wide variety of corrosive ingredients. The soil itself may consist of sand, clay, chalk or many other types. It may be well aerated or relatively air-free (i.e. anaerobic) depending, amongst other factors, on the depth below the surface at which the metal being considered is buried. The soil water level may permanently above or below this level, or it may fluctuate seasonally above or below the buried metal. Furthermore the actual operation of burying the metal in the soil will affect the final environment; the soil resting against the metal may come originally from a greater or lesser depth and be different in composition at different parts of the metal surface, thus encouraging localized corrosion. Artificial backfills may be employed around the metal, especially if it is a pipeline or cable. One even has to consider the real possibility that the trench or pit dug to take the metal may become a sump or drain and fill up with water, so changing completely the corrosive conditions to which the metal is exposed. In the face of these great complexities it is difficult to develop a theoretical approach to soil corrosion. One of the most useful yardsticks has proved to be the electrical conductivity of the soil since high conductivity is obviously conducive to the flow of corrosion currents between parts of the
metal exposed to different local environments. Conductivity alone, however, is no safe guide to corrosiveness. Porosity and aeration, dissolved salts and acidity must also be considered if even an approximate forecast is serious. Yet, in spite of this apparent complexity, one of the first of the major corrosion problems to yield to a theoretical approach was that of the soil corrosion.

Soil is largely made up of insoluble mineral particles that do not directly affect corrosion. The spaces between the particles contain the air and water, dissolved salts, organic matter, and bacteria responsible for corrosion. Soil is made up of particles of different sizes classified as sand, and clay, from coarsest to the finest. All the particles have a surface film of moisture. Fine clay is not corrosive, because its particles fit tightly against each other, tending to exclude air and oxygen, but anaerobic bacteria and acidic conditions can often develop in swampy regions. Peat (containing over 50% organic matter), usually found in swamps, decompose organic matter to produce H2S and CO2 gases that dissolve to acids. Generally, peat and clay are mostly corrosive. Light, sandy soils are least corrosive. Loams are mixtures of sand, silt, and clay, which produce cathodic regions and anodic regions all over the surface of buried metals. Oxygen concentration cells, low PH, and bacteria are responsible for much corrosion.

Chemical Reaction:

The rusting of iron can be described in the form of a simple chemical reaction as:

$$\text{2Fe} + \text{2HO} + \text{O}_2 = \text{2Fe (OH)}_2 \ldots \text{eq. (6)}$$

There are two components to this reaction:

- Transfer of a positive charge from the iron to the electrolyte with consequent oxidation of the metal.

$$\text{2Fe} = \text{2Fe}^{2+} + 4\text{e}^- \ldots \text{eq. (7)}$$

This is called an anodic reaction.

- Transfer of a positive charge from the electrolyte:

$$\text{2HO}_2 + 4\text{e}^- = 4[\text{OH}] \ldots \text{eq. (8)}.$$  

This is called a cathodic reaction.

The net transfers of charges in the anodic & cathodic reactions balance out. The locations on the surface where anodic reactions occur are called anodes & cathodic reactions occur at cathodes. When the corrosion is concentrated at one location corrosion pits are formed. In this case the site of the pit will have been consistently anodic with cathodic reactions taking place on the surface around the pit. When a visible distance separates the anode & cathode, it is more obvious that an electric current must flow between them in order to maintain the balance of charge transfers across the metal – environment interface. This current is called the corrosion current, which flows from the steel at the anode through electrolyte, and back onto the steel at the cathode, current flows through the steel from the cathode back to the anode to complete the circuit. The driving force for the corrosion current flow
is electrochemical reactions at the steel–environment interface. Anodes cathodes occur spontaneously on a wet steel surface. Whether an individual location acts as an anode or cathode may be influenced by:

- Small-scale variation in steel chemistry.
- Differences in the surface condition.
- Variation in the environment such as oxygen condition.

All metals corrode to a greater or lesser degree in a wet environment, in each case the corrosion reaction is marked by development of a potential across the interface between the metal and the environment. This potential can be measured and gives an indication of reactivity of metal 4.

**Galvanic Series:**

The galvanic series is used to describe relative reactivity; least reactive show relatively positive potentials whereas corrosion susceptible materials, or base metals show relatively negative potentials. When any two of these metals are electrically connected together in a wet environment, a current will flow such that:

- The interface potential of the carbon steel will be shifted negative or cathodic so that cathodic reactions dominate at the metal–environment interface.
- The interface potential of the zinc is shifted positive or anodic so that anodic reactions dominate at the metal–environment interface.

The result of these potential shifts is that the carbon steel does not corrode [it is cathodic] but zinc does [it is anodic].

Because soil is often an effective electrolyte a galvanic cell establish between a pipeline and another piece of buried metal, or between two areas on the same pipeline when a new piece of pipe is attached to an old pipe. Dissimilar soil with differences concentration of ions, oxygen, or moisture concentration will set up anodic & cathodic regions on the pipe surface. Corrosion cells of this type are called concentration cells.

**Soil Corrosivity:**

Soil having high moisture content, high dissolved salt concentration and high acidity is expected to be the most corrosive. However, soil composition alone has been found to have little correlation with soil corrosivity. Most of the entrained soil water or moisture is relatively noncorrosive in the short term. In the long term, the residence time of water or moisture on the metal surface will control the degree of corrosion in soil. Measuring this residence time is difficult or impossible in practice. Therefore, it becomes necessary to use more easily measured soil characteristics, which have uncertain correlation with corrosivity.

Soil corrosivity is primarily a measure of how well the soil can act as an electrolyte to promote galvanic corrosion on the pipe, secondarily, elements of the soil that may directly or indirectly promote corrosion mechanism.

**Soil Resistivity:**

The other major factor affecting corrosion is the soil resistivity, which determines the efficiency of electrochemical cells and quite easy to
Corrosion rate on buried metal will be greatest with the lowest soil resistivity. At low soil resistivities the flow of the corrosion current in the corrosion cell is easier. Low resistivity is also associated with high water and soluble salt contents in the soil and this aids transport of corrosion products away from the anode.

**Electrical Conductivity:**

The electrical conductivity of the soil is another important factor with respect to localized action, and depends mainly upon the concentration of salts, and other electrolytes in solution and also upon the quantity of soil water present.

**General soil condition:**

The nature of the soluble salts in the soil influences the corrosiveness of the water. Soluble salts in the various soils according to the system outline by C.Palmer, U.S Geol survey bull include four main groups:

- **Primary salinity** is due to the alkali (sodium & potassium) salts of strong acids.
- **Secondary salinity** due to the alkali-earth (calcium & magnesium) salts of strong acids.
- **Primary alkalinity**, due to the alkali salts of the weak acids, and secondary alkalinity due to the alkali-earth salts of weak acids.

In all cases of rapid failure, calcium sulfate & sodium chloride are frequently found in corrosive soils. Indicate that the action of calcium sulfate is due to the hydrolysis of the sulfate that results in the formation of free sulfuric acid in the solution, and sodium chloride seems to attack and destroy most natural protective coating. Where soil waters containing deferent materials in solution, or varying concentration of the same solution, are in contact with the metal surface, local corrosion usually occurs. In the cases of varying concentration, a current has been found to flow in the water from weaker to the stronger solution. The direction of the current produced depends on the composition of the electrolyte, also note that different soils in contact with the same piece of metal may cause vary marked local corrosion.

Corrosion is the most severe in the corrosive soils with:

- A/ low resistivity < 2000 ohm-cm
- B/ soil contain a lot of water.
- C/ soil contain soluble salts.
- D/ High PH (alkaline) > 9
- E/ low PH (acidic) < 4
- F/ soil contains industrial waste.
- G/ the redox potential is <250 mv

Note: The redox potential is a measure of oxygen activity in the soil.

**2.6 Corrosion Control Methods:**

Steel pipes buried in the soil will corrode unless they are protected. In principle cathodic protection can be used to control corrosion of buried steel, but the total current demand for a large metal structure, such as a pipeline, would be too large if the structure had no coating.
The principal methods for mitigating corrosion on pipelines are

1/ Coating
2/ Insulation joints
3/ Cathodic Protection

2.6.1 Coating:

External corrosion protection coating for buried steel pipelines provides the first line of defense against corrosion. Steel is the most commonly coated material to improve its corrosion resistance. Before coating is applied, the base metal surface must be thoroughly cleaned mechanically by wire brushing or grit blasting.

Damage to pipeline coatings is arises as a result of:
- The transportation, storage and construction.
- Handling, ditching and backfilling during construction.
- Soil compaction, settlement and movement during and after backfilling.
- Deep ploughing, drainage works or excavations over the pipeline.

Coating Type:

Over the years since the start of large scale pipelining there have been, and continue to be, many developments in coating materials and protective coating systems. The objective is to find materials that will have the possible electrical and mechanical strength, ease of application and stability in long-term performance, all at a cost compatible with economical pipeline construction. The types of coating are:

- Enamels, is usually applied to hot- applied coatings of coal tar or asphalt, both of which has been in use for many years.
- Waxes, are similar in performance to the asphalt and coal tar enamel, they are usually applied in thinner coats.
- Mastic, this term is commonly used to refer to materials, which are formulated with selected sands, and other inert materials bound with an insulating compound.
- Greases are applied usually by smearing on with the gloved hand.
- Cold Applied Liquid Coating. Coating in this category includes materials that are applied in a cold liquid form and solidify either by solvent evaporation or chemical cure.
- Tapes, being used as a full coating system include plastic films, with a self-adhesive backing applied to a primed pipe surface for best results.
- Plastic Coatings are applied for small diameter pipe used in distribution systems.
- Wrappers and Shields are used to increase the mechanical or electrical strength of coatings and /or to provide an outer barrier to help prevent damage by material in the backfill.
- Weighted Over- Coatings are used under water or in a non- stable fill; they must have sufficient negative buoyancy to prevent their floating to the surface.
Concrete Coatings are not commonly used as application coating; suitable compounded concrete can protect steel against corrosion very effectively.

2.6.2 Insulation joints:
Insulation joints are used to break the metallic electrical connection between the anode & cathode, and thereby prevent the flow of current between the two. This method has limited applications. Insulation joint can, for example, be used at the junction of two dissimilar metals but obviously would not be effective in the control of localized corrosion cell on the surface of the structure.

2.6.3 Cathodic Protection (CP):
Cathodic protection is very simply, the use of direct current electricity from an external source to oppose the discharge of corrosion current from anodic areas, when a cathodic protection is installed for maximum effect, all portions of the protected structure collects current from the surrounding electrolyte and the entire exposed surface becomes a single cathodic area—hence the name.

Cathodic protection properly designed & maintained can control pipeline corrosion effectively; steel system has been demonstrated in countless instances. The roof of this effectiveness has been most apparent where protection has been applied to old piping systems that had been developing leaks at a rapidly increasing rate. Suitable protection systems can stop the developing of further leaks in the dramatic fashion.

Type of Cathodic Protection:
Two types of cathodic protection are available:
A/ Sacrificial (galvanic) cathodic protection is used on small structures, for short-term protection, where electrical power is not available.
B/ Impressed-Current cathodic protection is used for extensive systems and systems where corrosion conditions must be known at all times (extremely corrosive environments).

The promotion of scale formation on pipelines is less critical because all pipelines are coated and the damage level on pipeline coating is normally less than the damage level on jacket coating. However, the current demand figures published by DnV for steel structures do give an indication of the variation in CP current densities required to maintain effective protection at various locations around the world.

Current Requirements:
The actual cathodic protection current requirement for pipeline depends principally on the condition of the coating, whether the pipeline is to be fully buried, and the temperature of the product to be transported.

The basic current requirement is given by the formula 12:

\[
\text{Current Prevailing} = (\text{current density for protection of bare steel in the conditions}) \times (\%\text{Coating breakdown}) \times (\text{total surface area of the pipeline})
\]

No correction is required to the current density for protection at product or environment temperatures below 25°C but a correction is necessary above this temperature.

Current Supply:
The current supply for a CP scheme can be provided in two ways, by galvanic anodes or by impressed current. Early anode designs were most commonly based on the use of US Military Specification Zinc which provides ~ 780 ampere hours of
current per Kg of anode material. Zinc anodes are to be avoided on high temperature lines because zinc suffers Intergranular attack in saline mud at temperatures above 50°C.

2.7 Corrosion Control

Offshore pipelines normally should be constructed with a sacrificial anode cathodic protection scheme; most are usually with bracelet anodes spaced at regular intervals along the pipeline. Coating defect location techniques must be based on the injection, and detection. AC signals are not appropriate for these pipelines because the signal would be dissipated at each anode.

1/ External Corrosion Control:

External Corrosion control is normally achieved by the use of a protective coating and, on immersed or buried structure, cathodic protection. The reliable on the measurements of the cathodic protection system are:

- Potential measurement by direct contact.
- Potential measurement using a mobile reference electrode
- Potential measurement by direct contact and remote electrode extrapolation.
- Current density measurement by extrapolation from field gradient measurements.
- A combination of methods is normally applied to achieve a reliable survey result:
  - Direct contact potential measurements on the bracelet anodes.
  - Continuous recording of the voltage gradient along the pipeline.
  - Extrapolation of the potential values by using previously measured current density and voltage gradient values.

Survey Techniques:

Survey systems are typically comprised of a survey vessel linked to an ROV (remotely operated vehicle) by an umbilical cable. The ROV holds a multi-element probe, which measures:

- Water temperature
- Water resistivity
- Pipe-to-water potential by stabbing to achieve electrical contact at the bracelet anodes.

As the vehicle travels between the anodes it measures the field gradient, due to Cp current, between the multi-element probe mounted on the vehicle and a remote reference electrode mounted on the umbilical cable. The potential along the pipeline are estimated by extrapolation from the IR drops due to the potential gradient in the water around the pipe. Due allowance is made in the estimates of potential for the effect of burial.

The current density profile shows negative peaks at anodes and positive peaks at areas of coating damage. An alternative, and less precise system, uses a reference electrode that is towed along the line of the pipeline.

Coating Defect Location Survey Techniques:

Coating defect location surveys on buried pipelines should be carried out from above ground by direct, or indirect, measurement of an electrical signal injected onto the pipeline.

Basic Principles:

The protective coating on the outside of the pipe is an electrical insulator. A current injected onto the pipe steel will flow along the pipeline until it reaches a break in the pipe coating. At this point some of the current will leak into the surrounding soil. This current leakage creates two effects:
A/ The current leakage reduces the magnitude of current flowing in the pipe beyond the break in the pipe coating.

B/ The current flowing out of the break in the pipe coating creates a potential gradient in the soil around the area of the coating defect.

The magnitude of current flowing off the pipe at the break in the coating depends on the area of damage to the coating and the resistivity, or conductivity, of the soil at that location. The contact resistance between the exposed pipe steel and the soil is given by the following formula;

\[ R_1 = \frac{\rho}{2d} \]

Where:
- \( R_1 \) = the contact resistance
- \( \rho \) = soil resistivity
- \( d \) = defect diameter

For a porous coating, where the current leakage path is through very small, water filled pores in the coating, the contact resistance is given by:

\[ R_2 = \frac{4t\rho}{d^3} \]

Where:
- \( R_2 \) = the resistance of the pore through the coating
- \( t \) = the thickness of the coating
- \( \rho \) = resistivity of the soil water
- \( d \) = pore diameter

**The Main Types of Survey:**

**A / Conductive AC Surveys:**

It is synonymous with the Pearson survey. An AC signal is injected onto the pipeline from a power source connected between a cathodic protection test post and an earth pin located ~ 100m to one side of the pipeline. At coating defects the AC signal leaks to the earth and flows via the soil to the earth spike to complete the electrical circuit. The localized current flow out of the coating defect creates a potential gradient in the soil and this is detected by potential gradient measurements at the ground surface. Two surveyors carry out the Pearson survey. Each surveyor wears spiked boots to ensure good ground contact, and these are connected to the tuned receiver that monitors the potential difference between the surveyors. The potential difference can be relayed to the surveyors as an audio signal, via headphones, or can be fed directly into data logger. The surveyors walk the pipeline at a spacing of about 10 meters either in- line above the pipe, or with one surveyor over the pipe and side of the pipeline. In either case the potential gradient measured between them will be at a minimum when the pipe coating is sound. However, the potential gradient recorded at a defect differs between the two techniques.

With the surveyors walking in-line over the pipe the potential gradient recording at coating defects shows:

- A peak as the first surveyor walks over the coating defect
- A null when the coating defect is midway between the surveyors
- A peak as the second surveyors walking over the coating defect

With one surveyor walking above the pipe and the second walking ~ 10 meters to one side only a single peak is recorded in the potential gradient between them. This survey format is preferred when the data is recorded directly into a data logger.

The size of the measured potential peak correlates approximately with defect size subject to the limitations already mentioned. On coal tar enamel coated pipe defect sizing is limited in the size range 100-1000 cm². One prime function of
coating defect location surveys is to locate areas of mechanical damage to the pipe, and also can locate coating defects damage across a broad spectrum of size ranges. Corrosion may be associated with coating defects of any size but significant mechanical damage is associated with larger defects (>100 cm²) on coal tar enamel coated pipelines.

**Conductive AC Survey Method Problems:**
The technique relies on good ground contact and sensitivity can be lost if the ground surface is very dry or covered in thick vegetation.
Distinct changes in ground resistivity can create a potential difference between the surveyors that may be confused with a coating defect.
Long running coating defects, such as longitudinal cracks in coal tar enamel coatings caused by soil stressing, can be difficult to interpret because the extended peak in the potential gradient may be confused with soil effects.
Multiple coating defects that are spaced apart by less than the distance between the surveyors will not be identified clearly when they walk in-line over the pipe.
Sensitivity is lost if both surveyors stray off the line of the pipe.
Sensitivity is lost as the pipe depth increases.

**B / Inductive AC Surveys:**
The inductive AC Survey is essential the same as conductive AC technique except for the method of defect identification. The AC current injected onto the pipeline creates an AC filed around the pipe and the strength of this field is proportional to the amplitude of the AC signal. Logging the emf generated in a sensing coil array carried above the pipe makes measurement of the field strength. Loss of current from a coating defect creates a change in the field strength due to the pipe current and this is detected as change in output from the sensing coil. Analysis of the signal output from the receiver is based on the assumption that the AC current flowing on the pipeline produces a symmetrical AC field around the pipe. In this case the field strength can be related to pipe depth as follows:

\[ H = \frac{I}{2r} \]

Where:
- \( H \) = field strength
- \( I \) = pipe current
- \( r \) = radial distance of the receiver from the pipe

Normally two-coil array is used in the receiver in order that changes in depth may be compensated for using the equation:

\[ I = \frac{2(r^2 - r_1)H_1 - H_2}{H_1 - H_2} \]

Where:
- \( H_1 \) = field strength at radial distance \( r_1 \)
- \( H_2 \) = field strength at radial distance \( r_2 \)

The radial distance from the lower coil position to the centerline of the pipe can be computed as follows:

\[ r = \frac{(r_2 - r_1)H_2}{H_1 - H_2} \]

Current loss over a short distance is indicative of a coating defect or an electrical contact that is draining current from the pipe.

**The inductive AC technique can be used in two main survey modes:**
- To walk the pipeline taking pipe current readings at the close intervals. Individual fault are identified by changes in the measured pipe current.
- By taking pipe current readings on a structured sampling basis to identify areas of current loss as quickly as possible, e.g. on a 1 km line section readings
would be taken at each end and the middle would identify 0.5 km section of the line showed the greatest current loss. Another reading would then be taken in the center of the 0.5 km section to identify where the major current loss occurred to within 0.25 km. This procedure is repeated until the location of the current loss is pinpointed.

**Inductive AC Survey Technique Problems:**

A. Error will be made in computing pipe current if the AC field is not symmetrical around the pipeline. Tight bends or adjacent pipes or metal structures may cause this.

B. At coating defects the pipe current leaking to earth generates its own AC field, which interferes with the AC field generated by the current on the pipe. This serves to obscure the distinct step in measured current expected at a coating defect.

C. The current measured by an inductive AC survey tool shows a distinct step in the survey profile when current is drained from the pipe by a cable connection. A less distinct step is seen when the same current is dissipated from a coating defect.

D. Small proportional current losses from small coating defects may not stand out against the background variation in survey readings.

**C / Conductive DC Surveys:**

The conductive DC survey is identical to the conductive AC in principle except that the signal used to create the potential gradient in the soil is the DC cathodic protection current flowing through the soil to the coating defect. There are three possible survey options. Two of them require a cable connection to the pipeline, so survey lengths are limited for these techniques. The cable connection is needed to make accurate measurements of the pipe–to-soil potential.

**The survey methods are:**

- An over-the-line, close interval survey with the CP current supplies switched on. This does not give an accurate estimate of the true level of protection and although a dip is normally recorded at coating defects the magnitude of the dip does not correlate with coating defect size.

- An over-the-line, close interval polarized potential survey. Normally this will be carried out as an “instant-OFF” potential survey because this gives a good indication of the true level of polarization on the pipeline provided there is no stray current activity on the pipeline. Individual coating defects are not located by this survey method but it does confirm the true level of CP protection.

- For the DC voltage gradient method an Hz DC signal has to be imposed on the pipe either as an additional current source or by switching the DC supply. Under protection by the applied CP can be influenced by the spacing between readings. More faults are detected when readings are closely spaced. In the longitudinal potential gradient survey a single surveyor walks the pipeline with a pair of matched reference electrodes connected to a sensitive, moving coil voltmeter. The meter needle shows a pulsed deflection as the surveyor approaches a coating defect. Above the defect there is no deflection of the meter needle. As the surveyor moves past the defect the pulsed deflection of the meter needle is reversed. This technique does not require a cable connection to the pipe but can locate coating defects and is claimed to give an indication of defect size. However, it gives no information on the level of protection. In the transverse potential one survey reference electrode is placed at remote earth, a minimum of 50 meters off to one side of the pipe. The
surveyor walks the pipeline with a second reference electrode and records the potential difference between it and the electrode remote earth. Where the coating is sound the potential difference is low. At coating defects the potential difference rises to a peak value when the surveyors are above the defect.

**Conductive DC Survey Method Problems:**
- Fluctuating stray current interference on the pipeline reduces survey accuracy for the ‘ON’ and ‘OFF’ potential surveys. Stray current sources may include traction systems and telluric activity.
- For the “instant- OFF “survey synchronized timers are need to switch all current sources in unison. This of course only applies to impressed current systems. The techniques are not really viable on lines protected by sacrificial anodes.

**2/Internal Corrosion Control**

The control of internal corrosion in carbon steel pipelines can be achieved in a number of ways:
- Increase the wall thickness to provide a corrosion allowance. If corrosion rates are expected to be very high this will not be a viable option.
- Remove the water from the product to a level at which the corrosion risk is eliminated. In the soil system the target level will be expressed as a water cut, in gas systems the target level will be a specified relative humidity. This option carries a cost and weight penalty if the pipeline originates from an offshore platform and provision would have to be made for appropriate actions in the event of failure in the water separation or dehydration system. This might include inhibitor injection or a shut down of the pipeline. At present product treatments of this kind are not possible at subsea completions.
- The constructing pipeline using a corrosion resistant alloy such as duplex stainless steel. This option carries a cost penalty of ~ x10 compared to the cost of a carbon steel pipeline. The cost difference is made up from higher material costs and slower welding rates during construction.
- The constructing pipeline using carbon steel pipes with internal cladding of a corrosion resistant alloy.
- Internally coat the pipe. Internal coatings are used for tubular and have been used in pipelines. If the internal coating is applied in a coating plant then provision must be made to coat the field joints in situ. A alternatively, if the complete coating is applied in situ then provision must be made for surface preparation of the pipe steel and for the cure of the coating. Some operators express concern over the durability of internal coating and provision must be made to cope with coating damage in service, for example by the injection of a corrosion inhibitor.
- Line the pipeline with a thermoplastic lining that, have been used for water injection lines but their use in hydrocarbon pipelines is limited by concerns over line movement and liner collapse rapid blow down. The over all cost of lined, carbon steel pipeline is similar to the cost for a carbon steel pipeline with corrosion allowance.
- Install a chemical treatment or corrosion inhibitor treatment programmed this requires storage and injection facilities at the pipeline inlet, so this option is not feasible for sub sea wellheads at present. Inhibitor transport can be a problem in pipelines depending on the product flow regime and it may not be
possible to guarantee that a sufficient inhibitor concentration is achieved at the points in the pipeline where water segregates and collects.

2.8 Corrosion Monitoring

1-Introduction:
On line monitoring can be used to check the effectiveness of both internal and external corrosion control measures. Ranges of monitoring techniques are available but they need careful selection, and careful placement, to ensure that the data obtained meets the objectives of the monitoring programmed.

1/ External Corrosion:
The performance of coatings and paint are monitored by periodic surveys to look for evidence of coating breakdown. Monitoring of cathodic protection systems is normally organized into a formal regime geared to ensure that the cathodic protection system provides effective protection through time and over the entire exposed surface of the protected installation. For offshore pipelines this is achieved by the use of periodic surveys to check pipe potentials and to check for continued current output from the sacrificial bracelet anodes.

2/ Internal Corrosion Monitoring:
Internal corrosion monitoring must be designed with a specific objective in mind, and these may include:

- Monitoring of corrosion risk. In a sweet gas system this could be restricted to monitoring of operational parameters such as pressure, temperature and dew point because corrosion risk can be predicted using this data. Where souring is expected periodic checks on the hydrogen sulphide content is essential because this changes the nature and time frame of the corrosion risk.
- Monitoring the effectiveness of corrosion prevention measures. Monitoring of water content, dew point, inhibitor injection rate and on-line probes to check for inhibitor effectiveness fall into this category.
- Monitoring for the absolute corrosion rate. This may entail on-line probes to give readings of instantaneous corrosion rates, probes to measure average corrosion rates over extended periods, or periodic surveys of wall thickness and metal loss.

Monitoring Techniques:
1/Coupons:
Corrosion coupons, fitted into retractable holders ensure exposure to the actual environment, are relatively cheap, and can be manufactured to reproduce the appropriate metallurgy. Coupons can only give an average corrosion rate determined by weight loss after an extended period of exposure. Coupon location is critical if the derived data is to reflect the worst case conditions especially where the corrosion occurs as a consequence of liquid drop out, heat transfer, or localized erosion-corrosion effects. Coupons can be used in most conditions.

2/ Electrical Resistance Probes (ER):
ER Probes are constructed using wire or plate of the appropriate metallurgy with a controlled cross section. Changes in the cross section area, as a consequence of corrosion, increase the electrical resistance of the probe. With appropriate temperature compensation the change in resistance can be used to indicate corrosion rate. ER probes can be interrogated in-situ and the change in probe resistance with time will give an indication of relative corrosion rates, but as with coupons the derived rate is an average over the time of exposure. The measurement of the electrical resistance of the probe is independent of the environment so ER probes can be used in wide range of conditions.
3/ Polarization Resistance Probe (PR):

Polarization probes are multi-element probes and to take a reading a current is imposed onto one, or more, of the probe elements. This current has to flow through the environment so the probes are only suited to monitoring in low resistivity, fully immersed conditions such as stratified water phase in the bottom of a pipeline. The read-out from the probe is the current required to create a potential shift of ~ 10 mV, a high current demand indicates a high polarization resistance. Corrosion rate is inversely proportional to PR and estimates of corrosion rate are derived from Stem-Geary equations. The calculated corrosion rate is approximate but the read out is instantaneous so short term changes in corrosivity can be assessed. Absolute measurements of metal-to-environment potential can be used to assess corrosion activity, as in the case of pipe-to-soil potential measurements for cathodic protection monitoring. This technique is not widely used for on-line probes because contamination of the reference electrode creates errors in the measurement of potential with time.

4/ AC Impedance:

AC impedance probes can also be used for instantaneous estimates of corrosion rate and are suitable for use in high resistance environments, such as the thin moisture films expected in condensing phase conditions. Some care is needed in the application and interpretation of AC impedance measurements.

5/ Instrumented Spools:

This requires the installation of an instrument spool into the pipe system and corrosion of the spool is detected around the full circumference. Care is needed to ensure that the spool is inserted into the pipeline at a location that gives a reliable indication of the corrosion that is occurring.

6/ Direct Sampling:

Direct sampling of the product gives an overall indication of the corrosion activity in the complete system. Iron counts on product samples will identify how much iron is entering the water phase by corrosion. This can be used to check the overall effectiveness of inhibitor treatments but gives no indication whether the iron in solution is derived from severe, localized pitting or very low levels of general corrosion on the whole system. Components thought to be at high risk from localized erosion — corrosion could be marked with radioactive isotopes, which pass into the water phase as corrosion occurs. Monitoring these signature isotopes in water samples can provide good information on the corrosion or erosion activity at such high-risk areas.

7/ Non-Destructive Testing (NDT):

A variety of NDT techniques can used to carry out periodic checks on wall thickness to give an indication of average corrosion rate with time and to check system integrity. These techniques include x-ray radiography. Ultrasonic or eddy current inspection, magnetic pig inspection and elastic wave pig inspection.

Chapter Three

3 Analytical Methods
3.1 Laboratory Test

It is essential when studying corrosion to collect and evaluate data from different sources which affecting the environment for a certain period. For example
when studying external and internal corrosion along buried pipeline the most important data to be assessed and evaluated are:

- Soil analysis along the pipeline route for a distance of ten kilometers it was done for each sample at a depth where the pipeline is bedded.
- Relative humidity for selective area along the pipeline route for ten years at least.
- Rainfall data for selective areas along the pipeline route for ten years at least.
- The specification of the different refined products and the flow system.

**Soil Analysis:**

**Apparatus:**
- 1/ PH meter
- 2/ EC meter (Conductivity)
- 3/ Flame photometer

**Test Procedure:**

1/ **Preperation of soil extract:**
   The soil extract was prepared by adding 100 ml distilled water to 20 gm of soil which passed through 2mm screen and was shaken well and was filtered through filter paper.

2/ **Determination of Soluble Cations:**
   - Na⁺ cation was determined from soil extract using Flame photometer.
   - Ca²⁺ cation was determined from soil extract by titration with EDTA (Ethlene diamine tera Acetate).

3/ **Determination of Soluble Anions:**
   1-Determination of Chloride:
   Chloride that is soluble in water was determined by silver nitrate titration.

**Reagents:**

A/ Potassium Chloride, 5% in water
   Dissolve 5g K2Cr O4 in 50 ml dil.water.
   Add 1N AgNO3 drop wise until a slight permanent red precipitate forms.
   Filter and dilute to 100 ml with dil.water.

B/ Silver Nitrate, 0.01N
   Dissolve 1.696g dry AgNO3 (150 ºc for 2hr) in dil.water, and dilute to 1litre.

C / Sodium Chloride Solution 0.01N.
   Dissolve 0.585g dry NaCl in 1-liter dil.water.Titratre 10 ml of this solution against reagent B after adding 4 drops of reagent A until permanent reddish brown color appears.
   Take the reading as a, and from this calculate the extract AgNo3, normality.

**Procedure:**

1/ About 5 ml soil saturation extract was taken in 150 ml Erlenmeyer flask.
2/A 4 drop of reagent A was added to 1.
3/ Then 2 were titrated against reagent B until permanent redish brown color appears.
4/ The-reading b was taken.
5/ two blanks in the same manner were run using distilled water to obtain reading c.

**Calculations:**

\[
\text{Cl}^{-} \ (\text{mg/l}) = (b-c)*N \ (100/V)
\]
Where:
N = normality of silver nitrate.
V = volume of soil saturation extract

2-Determination of Sulfate:
Sulfate can be determined by precipitation as barium sulfate

Reagents:
- Barium chloride 10%
- Methyl orange indicator
- Hydrochloric acid dilution

Procedure:
20 g of soil was passed through 0.2 screen in conical flask 300 ml and 100 ml distilled water was added & was shaken in mechanical shaker for 1 hr, and then was filtered through what man NO 42 filter paper.
The aliquot was put in 300 ml beaker and drops of methyl orange indicator & 1 ml hydrochloric acid were added till the color was changed to red.
Then the aliquot was heated in water bath, and was added to 1 ml of barium chloride solution, excess barium chloride solution was added and heating was continued for 15 min., then the aliquot was cooled, filtered the solution through aheless what man filter paper NO 42, the precipitate was put in dried, weighted crucible, the precipitate dried in muffle furnace at 750 ° C for 2 hr. then was cooled & weighed.
Calculation:
\[
\text{SO}_4 \% = \frac{\text{Weight of precipitate (g)} \times \text{weight factor} \times 100}{20 \text{ grams}}
\]

Where:

\[
\text{Weight factor} = \frac{\text{M.wt of SO}_4}{\text{M.wt of BaSO}_4}
\]

3.2 Inspection Data:
Technical Methods:
The development of high resolution in line inspection techniques is enabling engineers to select a method that seriously evaluate corrosion growth characteristic in pipeline. The inspection data was carried for SPP (Sudanese Petroleum Pipeline) was obtained by PII Group Limited, where the inspection was run in pipe in 2002- 2003, objective of this study to determine pitting and general corrosion in the body of the pipe (metal loss feature).

3.2.1 Cleaning:
Cleaning Tools:
I. Flexible Cupped Gauging Pig (pig type 1)
II. Single Module Magnetic Cleaning (pig type 2)
III. Dual Module Brush/Magnetic Cleaning Bulldozer pig (pigtype3)
IV. Pin Wheel Scraper Pig (pig type4)

Test Procedure
1/Cleaning:

The pre-inspection cleaning has been applied to each 7 sections of 8” pipeline, to avoid MFL sensors leakage, when the inspection maintain good contact with the wall of the pipeline, optimum data is obtained. The pre-inspection cleaning has been performed as the following sequence of pig runs per pipeline section:

Runs No1 (pig type1):

The first pig has been run a single module pig fitted with four flexible pig cups and support discs, and also was carried an aluminum gauging plate to 85% of pipeline bore.

Runs No2 (pig type2):

The single magnetic cleaning pig is fitted at each end with a disc, to remove ferrous debris from the pipeline.

Runs No3 (pig type3):

A dual module pig consisting of a steel brush pig fitted with disc close – coupled to magnetic cleaning pig fitted with discs using to remove any loose ferrous debris from the pipeline.

Runs No4 (pig type4):

Pinwheel scraper pig is designed to remove hard deposits from the pipeline wall.

Runs No 5 (pig type3):

Dual magnetic / brush pig.

Runs No 6 (pig type4):

Pinwheel scraper pig fitted with 100% coverage of scraper pins.

Runs No7 (pig type3):

Dual magnetic / brush pig.

2/Magnetic Flux Leakage Inspection (MFL)

A proven technology with principle use to locate metal loss, as the tool travels through the pipe, powerful permanent magnetize the surrounding metal via wire brushes that contact the internal wall. Flux density is driven to the point of saturation. Any change in the thickness of the metal in pipe wall a fitting, a weld or patch of corrosion causes disturbances in the magnetic field, sensors surrounding the circumference of the tool read these disturbances and record the data on the board. The characteristic patterns of flux leakage can be interpreted to establish the dimensions of each anomaly, using a ring of secondary sensors possible to discriminate between internal and external metal loss. Other data is recorded as the tools progresses. Odometer wheels log the distance traveled, and an internal pendulum records the orientation of the tools within the pipeline. A time based marker system is deluged along the pipeline right of way to log the time of passage of the tools. Tools are available in standard and custom diameter versions, with scout scan mapping capabilities, and with by pass speed control options.

Estimation of Corrosion Rate:

Estimation of corrosion rate was taken from the results of the PII analysis, which has been assumed that:

1/ External corrosion has been active for half of the pipeline life (i.e 12 years at the time of inspection):

\[ \text{Corrosion Rate} = \text{depth} \times \frac{\text{pipe wall thickness (6.35mm)}}{12 \text{year}} \]
\[ \text{Ex. rate} = \text{depth} \times 6.35 \text{mm}/12 \]

2/ Internal corrosion has been active for the full operational life of the pipeline (i.e. 24.1 years):

\[ \text{In. rate} = \text{depth} \times 6.35 \text{mm}/24.1 \text{year} \]
Determination of Estimated Repair Factor (E.R.F)

The estimated repair factor should be defined as pressure sentenced ratio *(ASME B31SENTENCED EQUATION)* which is calculated for each metal loss feature as following:

\[ ERF = \frac{MAOP}{P} \]

Where:

MAOP: Maximum Allowable Operating Pressure

P: Calculated Pressure, which is calculated from the equation:

\[
P = 1.1P_i \left(1 - \frac{2d}{3t} \right)
\]

When \( G \leq 4.0 \)

Or:

\[
P = 1.1P_i \left(1 - \frac{2d}{3t \sqrt{G^2 + 1}} \right)
\]

When \( G > 4.0 \)

Where:

\( P_i \) = internal design pressure

\( t \) = Nominal Wall Thickness

\( d \) = Peak Depth Metal Loss feature

L = Axial Length of the metal feature

D = Nominal outside diameter of the pipe

\( G = 0.893L / \sqrt{Dt} \)

Figure 3.2.1 show cleaning tools
Chapter Four
Results

4.1 Soil Analysis

Table 4.1 Soil Analysis Results

<table>
<thead>
<tr>
<th>Sample No</th>
<th>Location Km</th>
<th>PH</th>
<th>Soluble Ions mg/l</th>
<th>Resistivity Ohm cm</th>
<th>Electrical Conductivity ds/m</th>
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<td></td>
<td></td>
<td>Ca(^{2+})</td>
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<td>Cl(^{-})</td>
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### 4.2 Inspection Results

Table 4.2.a. External pitting depth and corrosion rate:

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<th>Corrosion rate mm/yr</th>
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Table 4.2.b. Internal pitting depth and corrosion rate:

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<th>Wall Thickness depth %</th>
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Table 4.2.1 External Features of More Than 1.3 E.R.F which should be Repair Immediate for Section A:

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<th>PREDICTED DIMENSION AXIAL CIRCUM. mm</th>
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<th>PRESSURE RATIO (E.R.F)</th>
<th>Corrosion Rate mm/y</th>
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Table 4.2.2 External Features of More Than 1.3 E.R.F which should be Repair Immediate for Section B:

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<th>DEPTH% WT</th>
<th>PRESSURE RATIO (E.R.F)</th>
<th>Corrosion Rate mm/y</th>
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<td>50729</td>
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<td>DEPTH % WT</td>
<td>PRESSURE RATIO (E.R.F)</td>
<td>Corrosion Rate mm/y</td>
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Table 4.2.3 External Features of More Than 1.3 E.R.F which should be Repair Immediate for Section C:

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<th>DEPTH % WT</th>
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<th>Corrosion Rate mm/y</th>
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Table 4.2.4 External Features of More Than 1.3 E.R.F which should be Repair Immediate for Section D:
Table 4.2.5 External Features of More Than 1.3 E.R.F Which should be Repair Immediate for Section E:

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<th>PRESSURE RATIO (E.R.F)</th>
<th>Corrosion Rate mm/y</th>
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Table 4.2.6 External Features of More Than 1.3 E.R.F which should be Repair Immediate for Section F:

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Table 4.2.7 External Features of More Than 1.3 E.R.F which should Repair Immediate for Section G:

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4.3 Relative Humidity Data:

Table 4.3.1 mean relative humidity (1992-2002) for Khartoum area:

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Table 4.3.2 mean relative humidity (1992-2002) for Shendi area:
Table 4.3. 3 mean relative humidity (1992-2002) for Atbara area:

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Table 4.3.4 mean relative humidity (1992-2002) for Port Sudan area:

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4.4 Rain Fall Data

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Figure 4.1 Pipeline Sections
Section A from Al-Rayyan to Shagara
Section B from Al-Rayyan to Shendi
Section C from Shendi to Atbara
Section D from Atbara to Booster station 111
Section E Booster station 111 to Booster station 11
Section F Booster station 11 to Booster station 1
Section G Booster station 1 to Port Sudan
Figure 4.1.1a Correlations between Corrosion Rate, Soil Resistivity and Electrical Conductivity
Figure 4.1.1b Correlations between Corrosion Rate, Soil Resistivity and Electrical Conductivity
Figure 4.1.2 Soil PH along the Pipeline

Figure 4.1.3 Soil Resistivity along the Pipeline
Figure 4.1.4 soil electrical conductivity along the pipeline

**IONS SOLUBLE ALONG PIPELINE**

Figure 4.1.5 soluble ions along the pipeline

Relative Humidity
Figure 4.2.1 mean relative humidity Khartoum Area

Figure 4.2.2 mean relative humidity Shandi Area
Figure 4.2.3 mean relative humidity Atbara Area

Figure 4.2.4 means relative humidity Port Sudan Area

Rain Fall Data
Figure 4.3.1 mean rainfall Khartoum area:

Figure 4.3.2 mean rainfall Shandi area:

Figure 4.3.3 mean rainfall Atbara area:

**PORTSUDAN AREA**

Figure 4.3.4 mean rainfall Port Sudan area
Figure 4.4.1 Correlation between Corrosion Rate & EC ds/m
Figure 4.4.2 Correlation between Corrosion Rate & Resistivity
Figure 4.4.3a Correlation between Ions Soluble (CL %) & Corrosion Rate

Figure 4.4.3b Correlation between SO4% & Corrosion Rate

Chapter Five
Discussion
Since external corrosion was found to be more severe in practice than internal corrosion, it will be discussed more intensive in this study.

Although when comparing soil properties at different location through pipeline route referring to the results, section G was found to be of low soil resistivity high electrical conductivity, high ions soluble (Na⁺, Cl⁻) and dry & alkaline. The metal loss scanning results identified in this section about 39686 corrosion features distributed along the pipes, 38945 of them externally, the deepest one about 76% from the wall thickness, while most of the rest features less than 30% in depth from the original wall thickness (6.35 mm). According to that, the normal situation along this section should be considered as severe area, since the atmosphere around where the pipes were buried was the worst along the route, but the actual data detected by the inspection tool seems that this section is the lower area corroded externally compared to section B which is worst, where the soil was classified as high soil resistivity, low electrical conductivity, low ions insoluble (Na⁺, Cl⁻) and very dry & alkaline soil. The corrosion features identified along this section about 61320 corrosion features, 60750 of them externally, the deepest one about 82% which is not in agreement with previous studies, where in section G (Port Sudan area) the soil was found to be very corrosive with low resistivity, high soluble salts, and high conductivity, acidic and wet. The buried pipes are subjected to a few number of external corrosion features while in section B (Shandi area), the soil was classified as non-corrosive with high resistivity, low soluble salts, and low conductivity and very dry & alkaline soil. The buried pipes are subjected to a high number of external corrosion features in this section almost twice that occurred along section G.

Referring to the results, section F was found to be of high resistivity, low electrical conductivity, low ions soluble (Na⁺, Cl⁻), and dry & alkaline soil. The results identified in this section about 9409 corrosion features, 7927 features external, the deepest one about 90%, while there are 99.5% of the external features was found corroded referring to the original wall thickness less than 30%. The soil in this section classified as non-corrosive. The results detected by inspection tool seems that this section have low corrosion externally, which is not in agreement with previous studies, although it has a deepest feature (90%).

Section E was found of low resistivity, low electrical conductivity, low ions soluble (Na⁺, Cl⁻), and dry & alkaline soil. The results identified in this section about 17966 corrosion features, there are about 16880 external features, the deepest one about 72%, while there are 96% of the external features found corroded referring to the original wall thickness are of less than 30%. This section is not in agreement with previous studies.

Section D was found of high resistivity, low electrical conductivity, low ions soluble (Na⁺, Cl⁻), and dry & alkaline soil. The results identified in this section about 49442 corrosion features, there are about 49011 externally, the deepest one about 88%, while there are 94% of external features found corroded referring to the original wall thickness are of less than 30%. This section is in agreement with previous studies, because the soil was classified as non-corrosive.

Section C was found of low resistivity, low electrical conductivity, low ions soluble (Na⁺, Cl⁻), and dry & alkaline soil. The results identified in this section about 50110 corrosion features, there are about 48502 externally, the deepest one about
89%, while there are 92% of the external features was found to be corroded referring to the original wall thickness are of less than 30%. This section is not in agreement with the previous studies.

Section A was found of low resistivity, high electrical conductivity, high ions soluble (Na⁺, Cl⁻), and dry & alkaline soil. The results identified in this section about 3764 corrosion features, there are about 3596 externally, the deepest one about 74%, while there are 91% of the external features was found to be corroded referring to the original wall thickness are of less than 30%. The soil in this section has been very corrosive, while it has a lowest corrosion externally, which is not in agreement with the previous studies.

The assessment of the data and excavation which was carried along the sections and the investigation carried around severe features indicate that:

1/ The most severe corrosion has detected by inspection tool is not caused by corrosive soil, but there are factors that caused this corrosion.
2/ The pipeline staff that is responsible for the line protection concentrate their effort at section G to protect the pipes from the external corrosion gives that very good result.
3/ Most of the features captured along sections B&C was found beneath the wrapping tape indicate that; the materials used in those sections are not of the same manufacturing process as the rest of the pipeline and from my view it look as if this section working as an anode to the pipeline system increasing the rate of the external corrosion also bad quality of wrapping tape and a bad working procedure since construction has made the tape desponded and is not in good contact with the pipes, so these desponded areas created these external corrosion cells.
4/ regarding the results of the investigation, we can conclude that the cathodic protection stations along sections B&C are not enough to protect the line, which means to increase the number of stations to facilitate the protection. Also locate the areas where the tape was desponded and carry a very urgent repair programme to stop the active corrosion cells beneath the desponded tape by using the latest means of wrapping tape technology.
5/ graphs assessment indicate that there is no correlation between the soil characteristic and the corrosion rate.

---

Chapter Six
Conclusion & Recommendation

7.1 Conclusion:

From PII Results it was found that:

External corrosions (225607 metal loss features) distributed around the complete circumference of the pipeline, this is common on small diameter pipelines coated in the field with cold applied tape. The distribution of corrosion along the length of the pipeline does not show a consistent
correlation with the applied CP. At some locations individual pipes show corrosion at the girth weld; this usually indicates that corrosion occurred before the pipeline was built. The most of external corrosion in the pipeline has been caused by a combination of pre-service corrosion and cathodic protection current shielded by coating that has lost adhesion. The corrosion in this case cannot be controlled by the use of cathodic protection. In section B Shandi area after excavation, notice that most features (82%, 6%...) are pitting & localized form under the tape; it means there is no coating defect.

Internal corrosions (3853 metal loss features) in the pipeline have been identified three phases, pre-service corrosion has been identified between 490 km and 570 km measured from Port Sudan it has been assumed inactive by PII inspection, and internal corrosion caused by the products transported before the year 2000 extends downstream from Port Sudan for 10 km and also assumed inactive. Corrosions have been identified in the pipeline downstream from the current inlet at AlRawyan in both directions. This corrosion may be active.

From investigation analysis found that:
The soil under which Sudanese petroleum pipelines was buried, found to be non corrosive soil and there are factors that caused the severe corrosion in some location on pipeline:
Because of a bad quality and bad wrapping of the coating tape during construction.
Because of the type of pipes used in some areas during construction where most of the severe features existed, since the type used was of bad manufacturing quality (ERW TYPE).
It is thought that it is due to existing contamination soils (mixed with coke) because of coating and cathodic protection can be effective in low resistivity soil and acid soil but will not provide protection in the presence of coke. When excavated some corrosion features found, all of them caused under tape without lost adhesion coating.

7.2 Recommendation:
From the results obtained, it is recommended that:

1/ Re-inspection with intelligent pig should be done to identify where the corrosion is active or not.

2/ Review the operating procedures products composition.

3/ The water content of the refined products should be reviewed regularly.

4/ the areas that have lost adhesion coating should be investigated, must be recoated to eliminate the problems of cathodic protection.

5/ the phenomena of the corrosion under tape must be considered.
6/ the stress corrosion cracking should be investigated.

7/ it will be necessary to surround the pipe with clean, inert granular backfill to separate it from the contaminated soil.

8/ Since soil corrosion analysis and investigation was very hard and complicated, I recommend for more intensive and concentrated study.

Chapter Seven

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Appendices

Appendix A

Sudanese petroleum pipelines (SPP)
Design life of pipeline 20 years
Pipe spools manufacturing 1975/76
Construction date 1975/78
Commissioning date 1978

The petroleum products pipeline started construction since 1975 using a combination of seamless, spiral welded and electrical resistance welded (ERW) line pipe. “Between”1977-2000 the pipeline used to transport white petroleum products (Gas oil- Benzene- Kerosene -jet) from Port Sudan to Shagara. After 2000 the pipeline used to transport:
1/ Mogas from Khartoum Refinery to Port Sudan (exporting line)
2/ Gas oil from Khartoum Refinery to Shagara Depot for onuse products

Exporting pipeline specification:

Maximum capacity:
The maximum design capacity for exported line is around 600,000 ton per year.

Design basics:
Pipeline specification:
   External diameter 8 inches
   Wall thickness 0.25 inches
   Length 733 Km
Pipeline material: API 5L steel grade X42
Design code: ASME B31.4

Onuses pipeline specification:
Maximum capacity:
The maximum design capacity for onuses line is around 600 thousand ton per year.

Design basics:

Pipeline specification:
- External diameter 8 inches
- Wall thickness 0.25 inches

Length 82 Km
Pipeline material: Carbon steel API 5L grade X42
Design code: ASME B31.4

Pipeline data:

Essential data:
Pipeline route from P/Sudan to Khartoum passes through the following towns:
P/Sudan; eastern side of the town leaning to wands the sea through unpopulated area by then.
Haiya town; mainly railway employees of population of about 1500 people by then.
Atbara; town; passing through an area east of the town with the population of about 5000 by then.
Edamer the P/line passed on the unpopulated area on the eastern side of the town.
El Mahmia village; a population of about 200 by then.
Um Ali village; the line passes west of the village through unpopulated area.
Kabushia village; the line passes through the unpopulated area by then on the eastern side of the village.
Shendi town; the pipeline passes through unpopulated are on the eastern side of the town.
Wad Banaga village; the pipeline passes on the eastern side of the village through unpopulated area.
Kabbashi village; the pipeline passes on the western side of the village; through a cultivated land.
El Kadreo village; the pipeline passed on the eastern side of both the village and the railways. During the construction of the line, the area was not populated but now both sides of the pipeline and the railway lines are densely populated with a population density of over 15.000 till the industrial area of Khartoum North.
Kober; the pipeline passes through an empty space west of the signaling corps to a P/I in front of the maintenance corps eastwards along to Kober prison to another P/I to the south along the bridge
Buri; the P/I pass along the eastern side of Khartoum airport, which is an unpopulated area southwards.
El Sahafa; the pipeline runs between W/madani road and Elsahafa living quarters with a population of about 10.000 on both sides (western side of the pipeline and the eastern side of road). Till the southern end of the Sahafat; with a P/I westwards to El shagsra depot through Erkowit living quarters which was unpopulated by then. Erkowit living quarters has a population density of about 15.000 presently.

Location of cross along pipeline:

Road crossing at Oshuri km
Road crossing at Sowakin km
Road crossing at Haiya village km
Road crossing at Atbara town km
River crossing at Atbara river km
Railway crossing kht/north km
Road crossing at Kober km
River crossing at Blue Nile km
Road crossing at south of Blue Nile bridge km
Road crossing south of Kht. Airport km
Road crossing south of Sahafa living quarters km
Road crossing south of Sahafa living quarters km
Railway crossing at shagara depot.

**Location of pumping stations:**

P/Sudan pumping stations km 0.00
Erkowit pumping station km 94.6
Hayia pumping station km 214
Booster pumping station km 318
Atbara pumping station km 484
Elroyan pumping station km 737

**Location of major pipeline fittings (valves, hot taps etc)**

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Products Specification:
1/ Mogas Specification
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### Appendix B

**Chemical Treatments Internal Corrosion Control**

**Corrosion inhibitors:**

Corrosion inhibitors can be effective in protecting steel against the effects of both sweet and sour corrosion.
Mechanism of Protection

Surface filming inhibitors are normally used to provide corrosion control in wet oil or wet gas systems. These inhibitors are strongly adsorbed onto the metal surface and so form a barrier at the surface that stifles further corrosion reactions and reduces the corrosion rate to acceptable level.

Corrosion inhibitors are proprietary formulations, typically comprising several active inhibitor chemicals making up about 25% of the product, with 65% - 70% solvent and 0 - 10% surfactants. The inhibitor ‘actives’ have many generic forms, mostly but not exclusively, based on long chain organic nitrogen compounds such as amines, diamines, amides, imides, imidazolines or polyoxylated and carboxylated nitrogenous compounds. Formulations may be oil soluble/water dispersible or water soluble to suit the particular service conditions.

Inhibitors may be dosed into the system by continuous injection or periodic batch treatment. However continuous injection protection program will normally commissioned with a high initial dose rate or a batch treatment to establish a protective film as quickly as possible.

Batch inhibitors adsorb strongly onto the surface and once in place may endure for several weeks depending on the inhibitor, the flow conditions etc. film growth must be ensured so contact time is critical for establishing protection, but typically a protective film can be formed a few minutes.

Continuous injection is designed to provide a constant reserve of inhibitor in the product to constantly replenish damage to the protective film. The dose rate can be adjusted to optimize protection.

Inhibitor Transport:

Batch inhibitors are transported to the steel surface as inhibitor slugs but continuous injection inhibitors must be dispersed within, and carried by the flowing product.

In pipelines subject to regular sphere pigging for liquid removal the corrosion inhibitor may be dispersed in the liquid slug ahead of the pig. In this instance an effective inhibitor film may be maintained, even in areas of condensation if the pigging frequency is short enough. In areas where the pig dose not generates a full bore liquid slug full wetting, and inhibition; of the pipe wall not be achieved.

System Design for Inhibition

The key decisions to be addressed at the design stage regarding the use of inhibitors include:

- Whether inhibition is practicable in the expected environmental conditions
- How to get the inhibitor into the system
- Whether a batch treatment or continuous injection regime is most appropriate.
- Whether inhibition will be transported to all wetted surfaces in the system
- How and where to monitor the effectiveness of the corrosion inhibitor
- How to treat and dispose of the produced water containing corrosion inhibitor.
2/ Methanol Additions for Corrosion Protection
In sweet service, methanol in the aqueous phase can depress the corrosion rate. A methanol content of \( \geq 30\% \) will typically give a reduction in general corrosion rates of up to 90\% in low flow and turbulent conditions. It is effective against general corrosion in both complete protections against localized pitting corrosion unless a corrosion inhibitor is also present.

In sour service conditions a reduction in corrosion rate by only 7\% - 25\% can be expected.

Methanol is distributed between the liquid phase and the gas phase and condenses from the gas phase with water. For service temperatures above 60\(^\circ\)C methanol dosing may not be effective because not enough methanols will condense out with water.

3/ Glycol Additions for Corrosion Protection
Effectively for gas stream system which reduce relative humidity and dew point of the gas. If the relative humidity is depressed below about 50\%, and maintained at that level, then free water, and hence corrosion, should not occur. It takes time for the absorption reaction to reach equilibrium and so, unless a contactor tower is used, the pipeline immediately downstream of the glycol injection point may be susceptible to corrosion. In gas system glycol will be transported as a segregated liquid, for example as a liquid stream in the bottom of the pipeline, as a slug of liquid, or as discrete droplets carried in the gas phase. Dispersion is therefore very dependent on the flow regime.

Appendix C

Definition of Some Terms:

Acid: substance capable of producing hydrogen ions in water.
Alkali: water – soluble base.
Anode: electrode that oxidizes in an electrochemical cell.
Cathode: electrode on which reduction occurs in an electrochemical cell.
Cathodic Protection: corrosion prevention by flow of current from electrolyte onto a metal.
Cell: device-producing electricity, containing electrodes and electrolyte.
Current: the flow of electricity measured in amperes (A)
Electrochemical Corrosion: corrosion in which metal is oxidized and some reactant in the environment is reduced.
Electrode: electron conductor in contact with electrolyte in a cell.
Grain Boundary: the region of mismatch between adjacent crystals in a polycrystalline material.
Inhibitor: chemical added in small amounts to an environment to decrease corrosion, usually used to prevent internal corrosion.
Ksi: thousands of pounds of force exerted one square inch of material.

Loam: soil containing wide variation in size of mineral particles
Localized Corrosion: corrosion concentrated primarily at one or only a few places on a metal surface.
PH: scale of acidity or basicity; the negative logarithm of the hydrogen ion concentration.
Redox Reaction: reaction in which one substance gains electrons and is reduced in valence while another substance release electron and increase in valence.
Resistivity: electric resistance of 1 m length and 1m² cross-sectional area of specific material.
Silt: mineral particles in soil 0.002 to 0.02 mm in average diameter.
Uniform Corrosion: corrosion that occurs fairly evenly all over a metal’s surface.
Standard Codes: ASTM VOLUME 5, ASTM VOLUME 9, ASME B31, BS 1377
NBS: National Bureau of Standards

Appendix D
Coating & Cathodic Protection

Coating:
In the early of pipeline construction the steel pipe was delivered to site without a coating and the coating application was carried out just before ditching the pipe, which is still used but the surface preparation, by wire brushing and the coating application are now mechanized. Many of the modern, high performance coating cannot be applied on site and so the coating is carried out in a purpose built plant with appropriate controls for surface preparation, by grit blasting, and application. The overall cost of field-applied coating is cheaper than factory applied coating but many operators question the consistency of quality and long-term performance of field applied coating.
Coating Performance & Application:
Pipe coating can be grouped according to use. The main categories of coating are:
- Coating applied to the body of pipe and components in coating plant.
- Coating applied to field joints on site.
- Coating for special application.
- Coating for high temperature.
- Repair materials (are selected for compatibility with the coating already on the pipeline).
The generic coating types in each category are:

1) Pipe coating in a coating plant:

- Hot applied bitumen or asphalt with glass fiber reinforcement.
- Hot applied coal tar enamel with glass fiber reinforcement.
- Fusion bonded epoxy powder.
- Sintered polyethylene.
- Two layer polyethylene (PE over mastic).
- Three layer polyethylene (PE fusion bonded epoxy powder with an adhesive interlayer).
- Three layer polypropylene (PP fusion bonded epoxy powder with an adhesive interlayer).

2) Field joint coating applied on site:

- Heat shrink material applied over mastic.
- Heat shrink material applied over a copolymer.
- Fusion bonded epoxy powder.
- Three layer polypropylene.
- Cold applied adhesive tapes.
- Hot tape applied.

3) Coating for special applications:

- Epoxy coal tar.
- Polyurethane syntactic.
- Rubber/ EPDM/ polychloropene
- Urethane elastomer.
- Coal tar Urethane.
- Liquid epoxy.
- Foamed polypropylene.

4) Coating for high temperature applications:
- Arc sprayed aluminum.
- Epoxy phenolic.
- PTFE.
- Three layer polypropylene.

Coating Performance & Application:
A pipe coating must provide effective corrosion protection for the design life of the pipeline and to achieve this, it should stop water getting to the pipe surface, by remaining adherent to the pipe steel.

On welded steel pipelines general requirements for coating are:
 a) Coating must be adherent to the steel.

 b) Coating must provide an electrically insulating barrier.

 c) Coating must prevent water access to the pipe steel.

 d) Coating must withstand handling, bending and construction damage.

 e) Coating must compatible with the maximum operating temperature.

 f) Coating must withstand soil and backfill loads.

 g) Coating must not deteriorate with age.

These simple performance statements provide the basis for the range of coating tests that are incorporated into performance specifications for pipeline coatings. Each general requirement is broken down into a series of specific tests that are used to ensure fitness for purpose and quality control of coatings.

A full assessment program for a pipeline coating material is mostly undertaken in three stages:
Stage 1 Type Approval:
The preliminary evaluation of a new coating will normally be undertaken on test specimens in a laboratory based test program to establish whether the coating can meet the necessary test requirements.

Stage 2 Coating Procedure Qualifications:

The satisfactory performance that meets Stage 1 Type Approval is evaluated under full-scale application conditions in a coating plant.

Stage 3 Production Coating:

Production Coating produced within the agreed range of application parameters is monitored on an agreed sampling schedule to ensure consistent quality.

The detailed of coating tests used in the three stage testing will be different for each coating type, therefore there is not a definitive list of coating tests but examples of test for different coating types:

1/ Fusion bonded epoxy powder

Stage 1: Type Approval:

- Basic properties of the powder:
  - Infra – red spectrogram
  - Gel time
  - Particle size analysis
  - Density
  - Moisture content
  - Thermal analysis
  - Storage stability

Basic properties of the detached, cured coating film

- Freedom from voids and other defects
  - Tensile strength elongation
  - Dielectric strength
  - Water permeability
  - Water absorption

Basic properties of the cured coating on steel substrate

- Freedom from cissing and pin holing
• Freedom from blisters

• Freedom from sagging when applied to a vertical surface

• Flexibility

• Impact resistance

• Adhesion

• Hardness

• Resistance to cathodic disbanding

• Resistance to strain polarization cracking

• Adhesion after water immersion

• Resistance to adhesion loss and under film corrosion after exposure to:

• Humidity

• Salt spray

• Artificial weathering

• Thermal ageing.

Stage 2 Coating Procedure Qualifications
The coating applicator will declare the following parameters for pipe coating on a continuous production line:

• Quality plan

• Details of the powder system

• Pipe dimensions

• Pipe cleaning & methods for removing oil & chemical contamination

• Blast cleaning procedure & grit properties

• Profile of the blast cleaned pipe surface
• Dust removal

• Procedure for achieving coating cut back at the pipe ends

• Speed of the production line

• Pipe heating method, time & temperature

• Powder application method and details of recycled powder

• Cure time and quench/cooling procedures

• Inspection schedules

• Repair techniques.

The coating performance tests carried out on the pipe include:

• Check on coating thickness

• Holiday detection

• Impact resistance

• Adhesion

• Coating cure and glass transition temperature

• Flexibility

• Cathodic disbanding

• Strain/polarization cracking

• Adhesion loss on water immersion

Stage 3 Production Coating

The production coating process variables will be checked for compliance with the parameter declared for the procedure qualification test. In addition pipes will be checked for holidays, impact, cure and coating thickness.

2/Cold Applied Wrapping Tapes:

The performance tests carried out on cold applied wrapping tapes duplicate some of the tests applied to fusion bonded epoxy powder, such as
cathodic disbonding but different tests are included because the characteristics of the coating system are different.
A typical performance tests are:
- Tensile strength
- Tear strength
- Impact resistance
- Adhesion
- Water absorption
- Electrical properties
- Change in strength, weight and adhesion with thermal ageing
- Cathodic disbonding
- Penetration
- Soil stress
- Natural weathering

It will be seen from a comparison of the performance test schedules for fusion bonded epoxy powder and cold applied tape coatings that there are some common tests such as Impact, Water absorption, Cathodic disbonding. Differences in the test regimes relate to differences in the coating characteristics. For example soil-stressing dose not affect fusion bonded epoxy powder coatings, because the surface of the coating smooth and the soil slides across it, but soil stress can a major cause of failure in the tape coatings. Conversely the long-term performance of fusion bonded epoxy powder coating is strongly dependent upon good surface preparation, application temperature, and correct cure but tapes can more tolerant of application conditions.

Cathodic Protection
Pipeline CP Design Equations

The principles design process CP system for an offshore pipeline includes:
Total Current
\[ \text{Current (A)} = \frac{\text{Protected Area (m}^2) \times \text{Current Density (mA/ m}^2))}{1000} \]

The protected area is equivalent to the area of coating damage on the pipeline this may change with time. The current density required for protection may vary with location, depth and the product temperature.
Total Anode Weight

\[ \text{Weight (Kg)} = \frac{[\text{Current (A)} \times \text{Design Life (Yrs)} \times 8760]}{\text{Alloy Capacity (Ah/Kg)}} \]

The calculation of total anode material weight must take into account the utilization factor of the anode. Some proportion of the anode material will remain on a depleted anode and so dose not contribute to the cathodic protection system.

Anodes Number

The number and type of anodes must meet the requirements for the total anode weight and total current requirement.

\[ \text{No. Of Anodes} = \frac{\text{current required}}{\text{Individual anode current output}} \]

The current output from an individual anode may change with time as the anode material becomes depleted. This depletion process may change the shape surface area of the anode that will, in turn, affect the anode resistance and current output.

\[ \text{No. Of Anodes} = \frac{\text{Weight Requirement}}{\text{Individual Alloy weight of anodes}} \]

The utilization factor must be taken into account when calculating total anode weight.

Anode Output

The current output from individual anodes is calculated using Ohm’s law:

\[ \text{Anode Output} = \frac{(\text{Anode Potential} - \text{Steel Potential})}{\text{Anode Resistance}} \]

Anode Resistance

The formulae most commonly used for calculating the resistance of bracelet anodes are:

McCoy Formula:

\[ Ra = \frac{(0.315 \Phi)}{A} \]

Peterson Formula:

\[ Ra = 1.72 \Phi A^{-0.727} \]

Where:

- \( Ra \) = Anode Resistance (Ohms)
- \( A \) = Anode Surface area (cm \(^2\))
- \( \Phi \) = Environment resistivity (Ohm-cm)

For some anode designs the surface area of the anode may change as it depleted. This effect should be taken into account when assessing the effectiveness of the proposed CP system toward the end of the design life.

Anode Life

\[ L = \frac{(Wu)}{(EI)} \]

Where:

- \( L \) = Anode Life (years)
- \( W \) = Weight of anode alloy (Kg)
- \( \mu \) = Utilization factor
- \( E \) = Consumption rate of anode alloy (Kg/A.Yr)
- \( I \) = Mean anode current output (A)

Anode Spacing

CP system designers will normally specify fixed anode spacing, and this may based on custom and experience. Anode spacing may be calculated if it assumed that no major coating defects are present in the coating:

\[ 2L = \frac{2}{(gr)^{0.5}} \times \text{Cosh} \{\frac{Ea}{Em}\} \]
Appendix E

SOME METHODS OF PIPELINE FEATURES REPAIR:
1. REPAIR SHELL
   Normally this type of repair used when the corrosion is regular and localized

   Figure 8.E.1 show repair shell

2. PLIDCO CLAMP REPAIR:
   This type of repair used when there is a product leakage
Figure 8.E.2 shows plidco clamp repair
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