RESIDUAL LIFE ANALYSIS OF PIPELINES

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BONAFIDE CERTIFICATE

This is to certify that the work in this thesis titled “Residual Life Analysis of Pipeline” has been carried out by Prakash.K under my supervision and has not been submitted elsewhere for a degree.

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ABSTRACT

Pipelines are one of the safest, economical, environment friendly & the most applied means for transportation of oil & gas in the world nowadays .With over 16 lakh kilometres of major oil and gas pipelines spread around the world and more than 60 percent of it - aged over 20 years old, there are many reasons that exist to maintain the operational integrity of this key infrastructure. The primary drivers that exist, are the ever increasing regulations on existing pipelines & limited expansion potentials of many regions, put the limelight on the pipeline damage Evaluation & relating safety concerns.

If oil and gas represent the lifeblood of world's energy, transportation and manufacturing sectors, then the oil and gas pipeline system can be considered its blood vessels. In this paper, the aim is at making an suitable deterministic analysis for finding the residual life of pipelines which is subjected to corrosion defects, damages, aging & evaluate the safe working pressure ranges for it remaining life, which will result in reduced pipeline failure & can be utilize for its entire mechanical life span .Here the pigging data of the pipeline is obtained which will give exact dimensions and related details regarding the present condition of the pipeline allow to move ahead with the work. Here a steady state corrosion model is used to find the rate of corrosion which will provide with a real life similarity to the analysis & a study is also conducted to identify the influence of various parameters responsible for the failure of the corroded pipeline. Also the anode life of the pipeline is also evaluated for the understanding of its service life period and then the impact of various coating breakdown factors on its life time.

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CHAPTER 1

1.0 INTRODUCTION

Since the 20th century, with a large number of oil and gas pipeline laying, pipeline, after serving a long time, due to external interference, corrosion, pipe and construction quality and other reasons failure accidents occurred, resulting in fire, explosion, poisoning, and cause significant economic losses, casualties and environmental pollution. Through the pipeline integrity management, not only can greatly reduce the incidence of pipeline accidents, and avoid unnecessary and unplanned maintenance and replacement of pipes, resulting in huge economic and social benefits. The integrity of oil and gas pipelines, the pipelines are safe and reliable controlled working state, management may continue to take measures to prevent pipeline accidents.

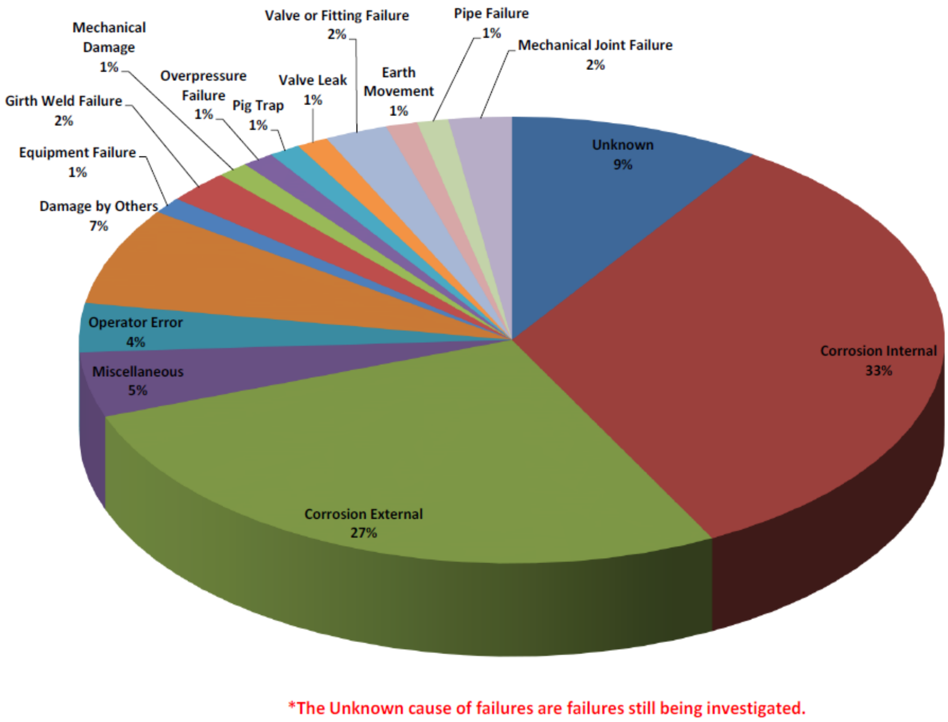
The integrity of the pipeline operation requires managers to constantly identify hazards facing operations, develop appropriate response and control measures, and may evaluate the risk of pipeline failure, propose feasible solutions. How to continue the rational use of existing pipeline, to avoid and reduce damage caused by pipeline hazards, increasingly governments and public concern. Pipeline integrity management has been abroad for several years of research and practice, has become the most popular international channels management.

The skill of maintenance and management of the industrial equipments has been emerged as a very important technique to be properly dealt with since the industrial apparatus becomes more complicate and diversified throughout all kinds of industries with the development of various mechanical techniques. It has been often reported as an industrial example in that a catastrophic disaster has been caused by the defect like corrosion arisen by aging and/or environmental effect in pipeline transporting gas and oil

1.1 **Current Scenario:**

Total of 93 pipeline failures in 2013 – 112 pipeline failures in 2012, Largest failure has a $4.3 million cost incurred to date, the cumulative environmental clean-up cost for 2013 was$18.7 million and in 2012 clean-up costs were $23.7 million.

Fig1.1: Major pipeline failure reasons



In essence, a corrosion management strategy should be risk-based and should take account of all aspects of asset maintenance, corrosion rate activity, historical and future operational parameters and the management and business requirements.

Oil and gas distribution via pipeline requires high level of safety and trust aiming at the reduction of costs, increase of operational efficiency and minimisation of accidents. It has been estimated, however, that approximately 40% of the world-wide pipeline network has reached its project life (estimated in 20 years) and efforts have been continually applied to further extend its residual life.

The structural integrity evaluation of pipelines is an important tool to minimise the risks of leakage and its impact on the environment enhancing the vital importance of the study of defects (cracks and corrosion pits) on the material's integrity.

According to the US Environmental Protection Agency, the number of oil spills has been reduced to less than 1% of the total volume handled each year (250 billion gallons of oil and petroleum products), meaning that over 2.5 billion gallons of oil and petroleum are still spilled every year only in the US. Accidents can happen during the oil production, distribution, storage and consumption process and it is very important to possess a detailed contingency plan (containment and recovery actions) to reduce the harmful effects of the oil spill.

Oil and gas pipelines can become susceptible to a whole variety of threats throughout operational life, which if not adequately eliminated it may eventually compromise pipeline integrity. One of the primary life-limiting threats is internal corrosion and therefore the requirement for effective corrosion management is vital.

1.2 Internal Corrosion Trends:

Trending of Internal corrosion incidents in pipelines over the past 30 years, however, shows a significant increase in incidence within the last 10 years, as pipelines age, operating conditions change, and pipeline mileage increases .

The first 10-year period (1970-1980), with the passage and enforcement of the Clean Water Act (1970) that introduced water into offshore pipelines, reported 35 pipeline leaks due to IC (6.8% of the total 30 year IC leak count).

The second 10-year period (1980-1990) recorded 92 IC leaks (17.7%).The third 10-year period registered 391 IC leaks (75.5%). Many were found to have recurred in the same pipeline but at different times.

The trend indicates that as the offshore pipeline infrastructure grows, ages, and continues to operate under harsh product-quality conditions, pipeline IC failures are likely to continue to increase. Internal corrosion pipeline leaks are often more prevalent downstream of producing gas wells that exhibit internal corrosion problems in production equipment and downhole tubing strings.

Under normal operating conditions, statistics indicate that most pipelines do not report internal corrosion leaks in the first 10 years of operational life. One reason for reduced failures in new pipe is the often designed-in corrosion allowance (6-10 mm maximum based on corrosion properties, inspection plans, pipeline criticality, and consequences of failure).

Currently, pipelines that were designed for 20-year life or less, with deep-water production expansion, may be expected to operate beyond their original design lives. Many older and once profitable short-life pipelines may have to be rehabilitated, retired, or re-laid because of internal corrosion.

The increase in IC leak reports over the last 10 years raises a red flag about such pipeline-industry issues as ensuring future pipeline reliability, safety, and integrity. This leak trend increase may be attributed to several factors:

- Development of new fields with harsher operational pipeline conditions.
- New production infusion into older inactive or low-flow pipelines.
- Increasing tendency for unseparated fluids to be transported as multiphase mixtures of oil, gas, and water.
- Changes in regulations.
- Major oil and gas companies selling older "marginal producing" facilities to smaller, untrained independent operators.
- Changes in companies' philosophies (restrictions in a company's operation and maintenance budgets because of product price fluctuations.

1.3 Scope

This report contains the technical details for analysis of life for an aged pipeline in the Bombay high field which transport sour gas to the Hazria plants. It includes all the technical aspects involved in the determining the mechanical life of the pipeline under active corrosion condition existing in the pipeline and finding the critical parameters which plays a crucial role in the failure of the pipeline .Also finding the influence of coating breakdown factor in remaining anode life of the pipeline.

1.4 System of units

Metric SI units shall be used throughout but the following exceptions shall apply:

- Pressure shall be expressed as either gauge pressure in barg or absolute pressure in bara, gauge pressure being referenced to Standard Atmospheric pressure of 1.01325 bara;

- Temperature shall be expressed as degrees Celsius (Deg C);

1.5 Aim:

The main aim of this is to find the residual life of a corroded pipeline using the code ASME 31 G as a basis for analysis.it involves the having a corrosion model for finding the quasi static corrosion rate in the pipeline to better understand the environment under which the pipeline is working. This will enable us to have more realistic framework for measuring the life for the working of the pipeline under the current operating pressure and find the critical parameters which affect its working. It also involves the finding the remaining anode life of the pipeline for various coating breakdown factors

CHAPTER 2

2.0 LITERATURE REVIEW:

2.1 Corrosion:

Corrosion is present in man's everyday life and also within the oil and gas business, it may be run into at every step. Corrosion attacks almost every component, as all metals and alloys are subjected to it. It can appear downhole or above the ground, on internal and external surfaces, destroying equipment and interrupting processes.

Corrosion is the main threat to the petroleum industry. Its enormous impact is shown in Table given below. The values in the table may be assumed as average ones, because they vary regarding to the country and region e.g. in Western Europe corrosion-related failures come to ca. 25%, in the Gulf of Mexico and Poland about 50%, while in India they reach 80% .

Table 2.1: Types of failure and its frequency

Type of failure	Frequency [%]
Corrosion (all types)	33
Fatigue	18
Mechanical damage/overload	14
Brittle fracture	9
Fabrication defects (excluding welding defects)	9
Welding defects	7
Others	10

2.2 Corrosion Mechanisms

Corrosion is an natural process, and the way in which it proceeds to attacks every metal has intrigued the human mind . However, to fully understand this phenomenon a detailed study of chemical, physical and mechanical properties of material is required. In the petroleum industry corrosion is initiated by a wide variety of mechanisms. They can be grouped into three categories: electrochemical corrosion, chemical corrosion and mechanical assisted corrosion.

2.2.1 Mechanical assisted corrosion

Stresses may increase corrosion especially on the casing joints and collars. They might be caused by the weight of unsupported casing, high differential pressures across the casing wall or pre-tension tubing force. This results in damage to the protective corrosion films allowing localized corrosion to take place. This form of corrosion is called corrosion fatigue.

Another common stress corrosion form is stress corrosion cracking, which occurs under a tensile stress and is constant over time. This corrosion starts at a pit and results in the formation of a crack. It is particularly dangerous, because it is difficult to recognize and may proceed rapidly. Tensile stress occurring in hydrogen sulphide environment may result in sulphide stress corrosion. In this case metal sulphides and elementary atomic hydrogen are formed and atomic hydrogen diffuses into the metal matrix.

A combination of tension and chlorite may also produce failures (chlorite stress cracking). Erosion corrosion covers the combined effect of corrosion and erosion. It is triggered off by fast-moving fluids and abrasive solid particles, which remove the protective coating and damage steel. In consequence, corrosion may occur at a faster rate and at new spots. It has to be added that the pure hydrocarbons are not corrosive themselves, so the corrosion is always initiated by other factors (most important are mentioned above).The "market" shares of individual corrosion mechanisms are presented in Table but naturally they may occur simultaneously.

Table 2.2 : Key reasons of pipeline failure

Cause of failure	Total failure [%]
CO_2 related	28
H_2S related	18
Preferential weld	18
Pitting	12
Erosion corrosion	9
Galvanic	6
Crevice	3
Impingement	3
Stress corrosion	3

2. 3 Corrosion in gas and oil transmission pipelines:

Corrosion problems in the transport and refining phases are only outlined. They are generally similar to those in producing wells. Transporting pipelines are protected internally by inhibitors, and externally by coating systems and cathodic protection systems.

Continuous monitoring of the transported fluid or gases by the means of various software programs ,that are based on the fluid and gas parameters, plays an important role to estimate the corrosion produced in the transported substances.

2.4 Corrosion rates and affecting factors

There are many ways of corrosion detection. Still, it is not enough to detect and then to assess the corroded area. It is also necessary to predict the deterioration of the flaw and calculate the strength of the pipe wall at the point of the next planned inspection. This forecast is based on technical norms, which take into consideration not only material properties, but also properties of oil, gas and the surrounding atmosphere. Standards differ between countries, regions or even companies.

Corrosion rates depend on many factors. One of the most significant is temperature. Normally it can be assumed that increasing temperature will lead to increased corrosion rates. This is caused by the temperature effect on the reactions kinetic and the higher diffusion rate of many corrosive by-products at increased temperatures.

The only exclusion is within an open system, when the corrosion is caused by dissolved oxygen in water. In this case a rise in temperature reduction in oxygen solubility in water and lowers corrosion rates. In a closed system, oxygen cannot escape, and a temperature increase results in increment of corrosion rates.

Another essential factor is pH. It is the negative logarithm of the hydrogen ion concentration and gives information about the acidity level. A decrease of pH values results in an increase of the corrosion rate. It should be remembered that other factors have an influence on pH e.g. the presence of carbon dioxide and hydrogen sulphide lowers the pH level to acidic regions and consequently encourages corrosion.

Oxygen concentration is another factor which affects corrosion. It increases rates of diffusion and accelerate corrosion. Fluid velocity plays also a crucial role. On a wide-ranging, the higher the velocity, the higher the corrosion rate, but as the limit of diffusion at a particular temperature is reached, further increases in velocity has little effect on the corrosion rate. Additionally, the solids carried by the oil or gas hasten corrosion rates.

Corrosion speed also depends on protection: selected material, coating, inhibitors. Material selection is especially significant. It presents the possibility to pick out material on their position in the galvanic series, which allows the control of the electrical current and respectively corrosion speed. It has application in design of connections and joints where different metals are used.

2.5 Cost of corrosion

Corrosion has spread to almost all branches of industry and became one of the most solemn problems internationally. Countries have to dig deep into their pockets to cover the consequence of corrosion. In several countries including the United States, the United Kingdom, Japan, Australia, Germany, India, and China the corrosion costs have been estimated. As a result of these studies, the annual corrosion costs, was ranged from circa 1 to 5 percent of the gross national product (GNP) of each nation.

The corrosion cost for the United States will be given in an concise manner. The total direct cost of corrosion in U.S. is estimated at $279 billion per year, which corresponds to 3.2 percent of the gross domestic product (GDP). This cost was determined by analyzing 26 industrial sectors, in which corrosion is known to exist, and consists of the cost of design, manufacturing, construction and the cost of management. However, there is also an indirect cost, and it is conservatively estimated to be equal to the direct costs. This means that the overall cost in the United States could be as much as 6.4 percent of the GDP.

2.5.1 Corrosion cost in gas and oil transmission pipelines

There are over 528,000 km of natural gas transmission and gathering pipelines in the United States, 119,000 km of crude oil gas transmission and gathering pipelines, and about 132,000 km of hazardous liquid transmission pipelines. The average annual corrosion-related cost is approximately $5.4 to $8.6 billion which can be divided into the cost of capital (38%), operation and maintenance (52%), and failures (10%). As a result of a number of pipeline failures during the last years (411 between 1994 and 1999 caused by corrosion), new regulations forced operators to put into practice in-line inspections. This technique allows finding corrosion flaws larger then 10% of pipe wall thickness. As a consequence, it is possible to assess the remaining pipe strength, and to avoid failures. The future cost of this pipeline inspection is estimated to be as high as $35 billion over the next 5 years. It seems to be obvious that the operators will search for some ways to save money, and this will be done by cutting corrosion operation and maintenance costs. This will lead, in the long-term, to increasing expenditures for pipeline replacement. Corrosion is the primary reason for aging and deterioration of pipelines.

It is assumed that all of the replacement costs are related to corrosion. Generally about 25% of the new capital costs are for the replacement of aging pipelines. The average cost of new gas pipelines in U.S. in 1999 was $746,000 per km, and about 6% of this amount was the cost of the corrosion protection (pipeline coating, cathodic protection system etc.).In order to optimize inspection frequency and maintenance, corrosion growth and life-prediction models are required. This, among other things, means that at the inspection stage, the cost-effective decision has to be made on the basis of measured and assessed corrosion defects.

2.6 Pigging:

The pipeline industry has, for many years, used scrubbing and scraping devices to clean the inside of their piping systems. These devices – called "pigs" – reduce build-up of waxes and other contaminants along the pipe's interior. Sophisticated and sensitive in-line inspection (ILI) tools travel through the pipe and measure and record irregularities that may represent corrosion, cracks, laminations, deformations (dents, gouges, etc.), or other defects. Because they run inside the pipe in a manner similar to the scrubbing and scraping devices known as pigs, these in-line inspection tools are often referred to as smart pigs."

Smart pigs are inserted into the pipeline at a location, such as a valve or pump station, that has a special configuration of pipes and valves where the tool can be loaded into a receiver, the receiver can be closed and sealed, and the flow of the pipeline product can be directed to launch the tool into the main line of the pipeline. A similar setup is located downstream, where the tool is directed out of the main line into a receiver, the tool is removed, and the recorded data retrieved for analysis and reporting.

2.6.1 Magnetic Flux Tools:

There are two types of tools commonly used for inspections of hazardous liquid pipelines based on magnetic flux measurements. A Magnetic Flux Leakage (MFL) tool is an electronic tool that identifies and measures metal loss (corrosion, gouges, etc.) through the use of a temporarily applied magnetic field. As it passes through the pipe this tool induces a magnetic flux into the pipe wall between the north and south magnetic poles of onboard magnets. A homogeneous steel wall – one without defects – creates a homogeneous distribution of magnetic flux.

Anomalies (i.e., metal loss (or gain) associated with the steel wall) result in a change in distribution of the magnetic flux, which, in a magnetically saturated pipe wall, leaks out of the pipe wall. Sensors on board the tool detect and measure the amount and distribution of the flux leakage. The flux leakage signals are processed, and resulting data is stored on board the MFL tool for later analysis and reporting.

A Transverse MFL/Transverse Flux Inspection tool (TFI) identifies and measures metal loss through the use of a temporarily-applied magnetic field that is oriented circumferentially, wrapping completely around the circumference of the pipe. It uses the same principal as other MFL tools except that the orientation of the magnetic field is different (turned 90 degrees).

The TFI tool is used to determine the location and extent of longitudinally-oriented corrosion. This makes TFI useful for detecting seam-related corrosion. Cracks and other defects can be detected also, though not with the same level of reliability. A TFI tool may be able to detect axial pipe wall defects – such as cracks, lack of fusion in the longitudinal weld seam, and stress corrosion cracking – that are not detectable with conventional MFL and ultrasonic tools.

2.6.2 Ultrasonic Tools:

There are two types of tools commonly used for inspections of hazardous liquid pipelines based on ultrasonic measurements.

Compression Wave Ultrasonic Testing (UT) :tools measure pipe wall thickness and metal loss. The first commercial application of UT technology in ILI tools used compression waves. These tools are equipped with transducers that emit ultrasonic signals perpendicular to the surface of the pipe. An echo is received from both the internal and external surfaces of the pipe and, by timing these return signals and comparing them to the speed of ultrasound in pipe steel, the wall thickness can be determined.

Of particular importance to successful deployment of a UT tool is pipe cleanliness, specifically the removal of paraffin build-up within the pipe. This is especially important for crude oil lines. The use of a cleaning pig is recommended prior to use of UT tools.

Shear Wave Ultrasonic Testing (also known as Circumferential Ultrasonic Testing, or C-UT) is the non-destructive examination technique that most reliably detects longitudinal cracks, longitudinal weld defects, and crack-like defects (such as stress corrosion cracking). Because most crack-like defects are perpendicular to the main stress component (i.e., the hoop stress), UT pulses are injected in a circumferential direction to obtain maximum acoustic response.

Shear Wave UT is categorized as a liquid coupled tool. It uses shear waves generated in the pipe wall by the angular transmission of UT pulses through a liquid coupling medium (oil, water, etc). The angle of incidence is adjusted such that a propagation angle of 45 degrees is obtained in pipeline steel. This technique is appropriate for longitudinal crack inspection.

2.6.3 Geometry Tools:

Geometry tools use mechanical arms or electro-mechanical means to measure the bore of pipe. In doing so, it identifies dents, deformations, and other ovality changes. It can also sense changes in girth welds and wall thickness. In some cases, these tools can also detect bends in pipelines. The remediation criteria in 49CFR195.452(h) depend on both the depth and orientation of dents, so geometry tools that are used to detect deformation anomalies such as dents, should be the type that provide both the orientation, location and depth measurement of each dent. This type of tool can be used in both hazardous liquid and natural gas pipelines.

2.7 Cathodic Protection

2.7.1 Background:

Typically, an external pipeline corrosion protection system consists of two components – the coating and the cathodic protection (CP) system. Corrosion takes place when electrons are removed from the metal at the anode area on the pipe surface and consumed by the reaction at the cathode with oxygen or hydrogen.

For corrosion to take place there must be:

- Anode (corroding area)
- Cathode (protected area)
- Electrically conductive metallic path connecting the anode and the cathode
- Ionically conductive electrolyte immersing the anode and cathode

There can be various causes of corrosion including:

Differential Aeration Cells: A pipe installed under a paved road in compact soil reduces the amount of oxygen at the pipe whereas as pipe in nearby ditches may be in aerated soil. Corrosion takes place in the pipe beneath the road.

Dissimilar Soils: In soils that are more conductive, corrosion takes place along those sections of the pipe.

New / Old Pipe: New pipe used to replace a section of line becomes the anode and corrodes, protecting the old sections.

These include quality of construction and protective coating systems, cathodic protection, nature of the environment, operating conditions, and quality and frequency of pipeline maintenance to name a few. No one factor influences the long-term integrity of a pipeline more than the effectiveness of its coating system.

Pipeline leaks, ruptures and ultimately a pipeline's integrity and useful life can be directly attributed to coating deterioration or failure. In the year 2000 it was estimated that of the 2.2 million miles of pipeline in the USA, 24% was more than 50 years old. This ageing of pipeline infrastructures and resultant coating deterioration has been the impetus for the development of methods and technologies to rehabilitate older facilities and extend the life of existing pipelines. New coating systems and application techniques have now been developed to enable old and existing pipeline systems to be upgraded in a cost-efficient manner, and to the latest industry standards for protecting facilities from external corrosion and environmental damage.

Most of the regulations that require pipeline to be coated and in general stipulate that a coating possess the following properties:

- Electrically isolate the external surfaces of the pipeline from its environment.
- Have sufficient adhesion to resist under film migration of electrolyte.
- Be sufficiently ductile to resist cracking.

- Resist damage due to soil stress and normal handling.
- Be compatible with cathodic protection.
- Resist deterioration due to the environment and service temperature.

Cathodic protection is fundamental to preserving a pipeline's integrity. Cathodic protection is a method of corrosion control that is achieved by supplying an external direct current that neutralises the natural corrosion current arising on the pipeline at coating defects. Current required to protect a pipeline is dependent on the environment and the number and size of the coating defects.

Clearly, for a particular environment, the greater the number and size of coating defects, the greater the amount of current required for protection. Coating plays an integral part in the functioning of a pipeline's cathodic protection system. Where a coating an integral part in the functioning of a pipeline's cathodic protection system.

2.7.2 Objective of the CP System

The anodic or corroding areas and the cathodic or protected areas on a pipeline are commonly on the same surface but separated microscopically. The coating system is the primary barrier against environmental corrosion while the CP system is a secondary defence to protect areas of the pipe that become exposed due to scratched, missing or damaged coating. CP is typically used to prevent corrosion at any weak areas in the coating such as field joints or damaged spots.

CP is fundamental to preserving a pipeline's integrity by replacing the electrons generated by the normal corrosion process. CP controls corrosion by supplying an external direct current that neutralizes the natural corrosion current arising on the pipeline at coating defects. CP prevents corrosion by converting all of the anodic or active sites on the metal surface to cathodic or passive sites by supplying electrical current from an alternate source. The current required to protect a pipeline is dependent on the environment and the number and size of the coating defects. The greater the number and size of coating defects, the greater the amount of current required for protection.

2.7.3 Cathodic Protection Systems

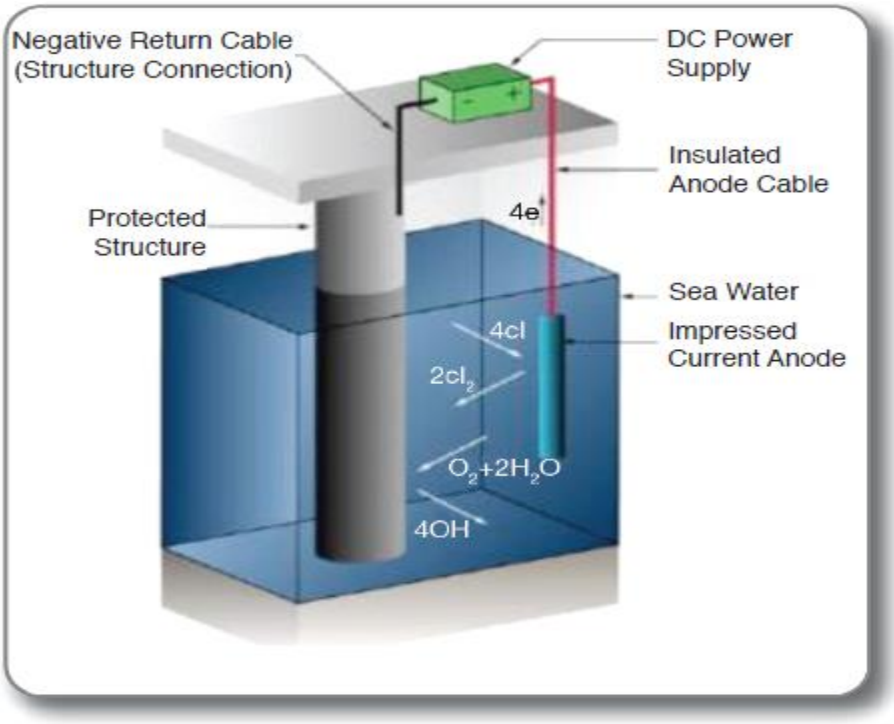
There are two main CP methods of providing protection against external corrosion – the impressed current and the galvanic protection methods.

2.7.3.1 Impressed Current Cathodic Protection

Impressed current CP describes the case in which the electric current for protection is provided by an external power supply. This type of system uses a ground bed and an external power source to impress current onto the pipeline. For a buried, onshore pipeline, a generator or a local utility provides the electricity. Commercially supplied AC is converted to DC. The system uses an anode bed and an external power source to impress current onto the pipeline. Impressed current protection involves connecting the metal to be protected to the negative pole of a direct current (DC) source, while the positive pole is coupled to an auxiliary anode. Electrons are introduced into the pipe and leak out at the bare areas where the cathodic reaction occurs. Impressed current CP is rarely used in subsea pipelines.

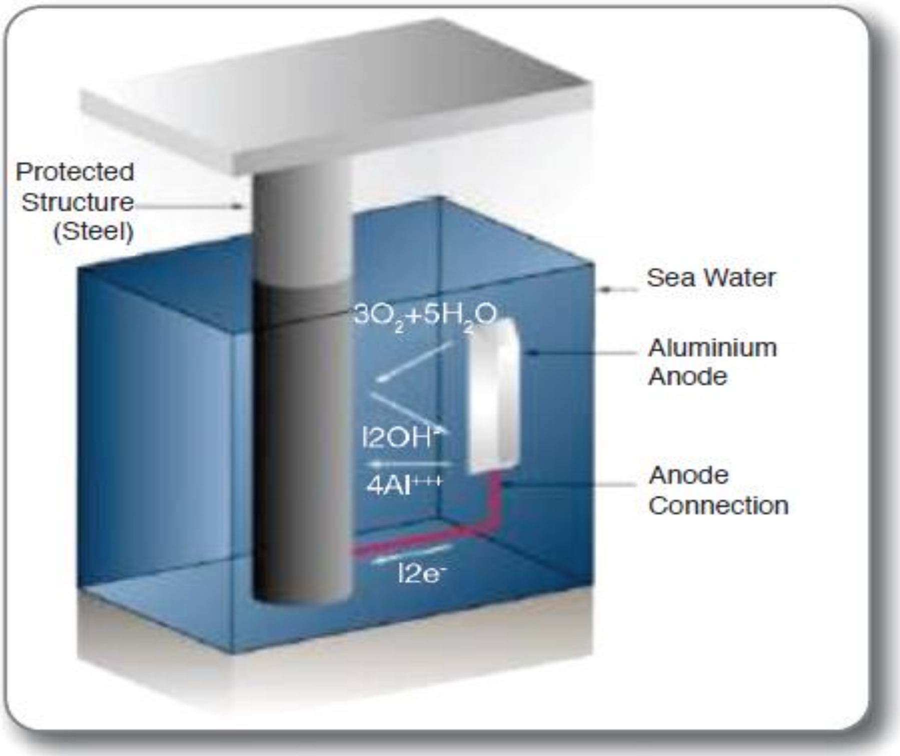
The ground bed is important for the effectiveness of the impressed current systems. It transfers current from the source through the ground to complete the circuit with the pipeline. One of the most common ground beds is the horizontal type with anodes installed with a backhoe at a depth below the frost level in the soil.

Fig:2.1 Impressed Current Cathodic Protection



Galvanic-Anode Cathodic Protection**:** Subsea pipelines are commonly protected by galvanic anodes. This method employs the basic conditions needed to produce an active corrosion cell: an anode, cathode, electrically conductive pathway and electrolyte; and a difference in energy level between anode and cathode. The flow of current through the electrolyte is always from the anode to the cathode. Wherever electrical current leaves the anode to enter the electrolyte, small particles of iron are dissolved into solution, causing pitting at the anode. Wherever the current enters the cathode, hydrogen gas is formed on the surface and the cathode is preserved and protected from corrosion. If one of the conditions above is removed, corrosion cannot continue. It is the removal of one of the conditions, to reduce or interrupt the flow of current, which is the basis for CP.

Fig2.2 Galvanic-Anode Cathodic Protection



For ground installations, the electrolyte is the moisture of the soil. The anode is a material having a more electronegative potential than steel. Typically, it is made from materials such as aluminium, zinc, magnesium or alloys of those metals. When the materials used as anodes are mechanically coupled to steel with an attachment wire, the steel pipe becomes the cathode. Subsequently, a current flows, and the anode corrodes to provide electrons that protect the pipeline.

CP trades corrosion on the pipe for corrosion on the sacrificial anode. The driving voltage (the difference in potential between the anode and cathode when coupled together in a corrosion cell) is limited with galvanic anodes; the amount of current that can be delivered tends to be low. Galvanic anodes are normally used in low resistivity soils to provide current to pipes having an excellent coating.

2.7.4 Anode Material Selection

Zinc has been in use as a sacrificial anode for longer than aluminium and is considered the traditional anode material. However, aluminium has several advantages as a sacrificial anode material and is now the material of choice (magnesium can be used for onshore pipelines but is not efficient for subsea pipelines because it corrodes rapidly in seawater and only provides about half the electric current for CP). Aluminium is capable of delivering more current in seawater and has higher a current capacity, so a lower consumption rate.

Thus a smaller mass of aluminium anode will protect the same surface for a given period of time as compared to a zinc anode. This leads to greater economy and improved performance in using aluminium as opposed to zinc. Moreover, the effect of operating temperature on the anode materials is very important. Zinc anodes alloy contains small quantities of iron which leads to inter-granular corrosion. Aluminium is also usually preferred to zinc because it is less expensive.

The temperature will have an important impact on the electrochemical capacity – as seen below the anode current capacity decreases as the temperature increases, reducing the CP effectiveness.

2.8 Bracelet Anodes

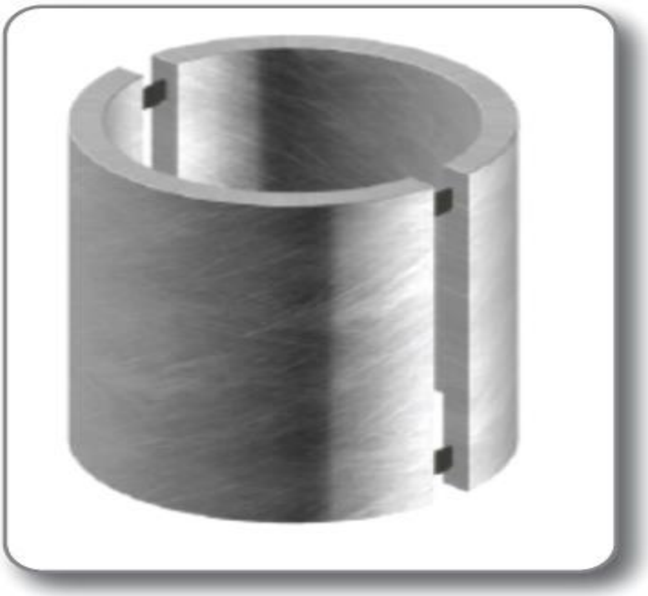
Today, almost all new pipelines installed are equipped with bracelet anodes. Two different kinds of materials are normally used: aluminium and zinc. Bracelet anodes are cast as two halves that fit together around the pipe. If there is no weight coating, the anodes are profiled with tapered ends, otherwise with shouldered ends when a weight coating is used.

Bracelet anodes may be fitted to the pipe as it is laid or retrofit anodes may be attached to the pipeline once it is in place. Retrofit anodes have the benefit of being separated from the pipeline and so are not exposed to elevated temperatures.

The anodes are electrically connected to the pipeline by copper braided wire (pigtails), one end connected to the steel insert and the other brazed or welded to the pipeline.

Tapered anodes are designed to be installed on pipelines with only a corrosion or insulation coating. It is to protect the bracelet anodes during the pipe-laying process, and stopping them snagging on the rollers used on the vessel firing line and stinger.

Fig.2.3 **Bracelet Anodes**



Even with these tapered designs, non-weight coated pipelines can still suffer anode damage, which can in turn cause coating damage. Several methods are being used to combat this problem such as polyurethane tapers or mounting both halves of the bracelet on top of the pipe thus avoiding contact with the stinger during pipe laying.

2.8.1 Retrofit Anodes

Retrofitting is normally used for the installation of additional anodes when a CP system is not adequate, or for extending the design life of the CP. It is also possible to use a retrofit system when it is not possible to use anode bracelet, for example where the temperature of the pipeline would render bracelet anodes ineffective. Finally, a retrofit CP survey is usually less expensive and easier to undertake.

2.8.2 Total net anode mass

The total net anode mass corresponds to the weight of anodes which must be used to provide sufficient potential protection to the pipeline over its life. The total net anode mass is directly related to the anode utilization factor and the electrochemical capacity of the material used. For example, as zinc and aluminium do not have the same properties, the total net mass required may change considerably. The table below shows the difference between materials for a pipeline with no external coating.

2.8.3 Anode utilization factor

The anode utilization factor is required because it is not possible to obtain 100% utilization of the anode material. Anodes are made by casting the anode material in a steel former. During fabrication the anode corrodes down to the inner ligature of the casting around the former, meaning the anode material loses electrical connectivity with the former, thus rendering a percentage of the anode unusable

2.8.4 Anode Numbers

The required number of anodes is calculated from the weight of each individual anode as a function of the total net mass demand. So if, we are using lighter anodes the number of anodes required will increase.

Because it is necessary to respect a maximum distance between anodes, it is important to find a compromise concerning the number of anodes. Using fewer anodes will reduce the cost of installation but may not provide sufficient current along the pipeline, whereas using a large number of anodes will provide sufficient current, but result in a higher installation cost.

The number of anodes is also dependent of the final individual anode current output and the demand for cathodic protection of a pipeline section. This will usually provide a lower anode numbers. But in order to have sufficient protection, the required number should satisfy both criteria.

2.9 Coating breakdown factor

The purpose of a protective coating on the pipeline is to restrict the access of oxygen to the pipeline and thus reduce the current demand. For CP design it is assumed that the protective coating is 100% effective except at areas of coating breakdown. The bulk of the protection current passes through the coating because all organic coatings are permeable to oxygen to some extent. When the oxygen arrives at the steel surface, it will remove electrons. This appears as a current flux through the coating.

As the coating ages, the resistance to permeation decreases and a higher oxygen flux occurs resulting in a higher current flow through the coating. The final coating breakdown has a higher value than the mean coating breakdown. This means that the coating will protect the pipeline less, and will be more prone to external corrosion.

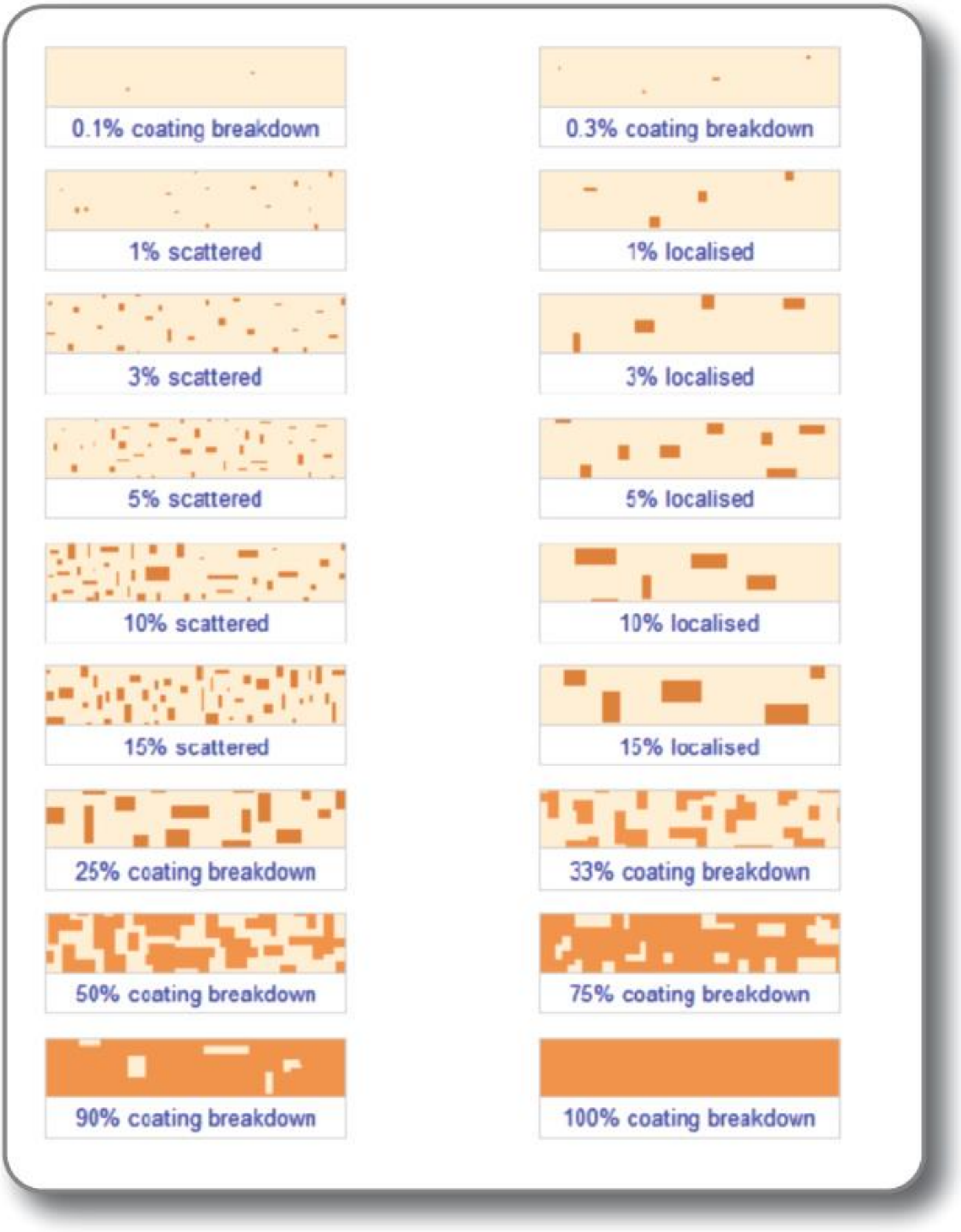
2.10 Cathodic Protection Surveys

Periodic inspection of the pipeline CP system is necessary to ensure that the system is functioning correctly. There is no corrosion allowance provided for external corrosion. A common approach is to inspect the pipeline shortly after installation, usually within the first year of service to ensure that the anodes are functioning and, then to resurvey about halfway through the design life of the CP system. The long delay from initial to second survey is acceptable because the coating on the pipeline should remain intact and the anodes are designed for protection of a significantly deteriorated coating.

2.11 Overprotection

Overprotection refers to the use of excessively high potentials to protect the pipeline. High potential can become a problem if the spacing between ground beds is too great or when poorly-coated lines are electrically connected to well-coated pipelines. Calculations take into account factors such as pipe resistance, soil resistivity, coating conductance and potential limitations to determine the spacing that meets the CP criteria without causing excessive potential near the ground bed. It may also be necessary to insulate segments with poor coating quality from those with good coating quality. Proper CP design should minimize overprotection.`

Fig:2. 4 Coating breakdown Factors



2.12 Coating System Performance

The coating system provides the primary means of external corrosion protection on a subsea pipeline – the CP system is considered the 'secondary' means of protection. The sections below provide details about the coating system used in the SBHT pipeline, and discusses the performance of equivalent systems installed around the world.

Coal Tar Coating System Overview:Coal tar enamel (CTE) and asphalt enamel (AE) coatings have a long and successful history of use throughout the world and, for normal grade coatings, are suitable for use on subsea pipelines operating at up to 55 ºC. Above this temperature limit, water absorption and dis bondment starts to become a problem. In this respect CTE coatings are considered to be marginally superior to asphalt enamel, due to their higher resistance to cathodic disbondment and the fact that coal tar generally absorbs less water than asphalts.

However, notwithstanding these slight advantages, the recent recognition of coal tar as being a potential carcinogenic material has resulted in, or contributed towards, a significant number of countries as well as individual companies excluding it from further use. The Yacheng Gas Pipeline (28-inch diameter by 778 km long) in the South China Sea, the second longest pipeline at time of installation, used CTE in 1993/1994. This pipeline has a 40 year design life. Asphalt Enamels do not have the same health and safety issues as CTEs, and are still specified and used in many subsea pipelines. Coal tar is a by-product of coke production.

The coal tar pitch is mixed with coal tar oils and an inert filler material, such as talc or slate dust, to produce coal tar enamel. Asphalt enamels are manufactured as an end product from the refining of crude oil, and essentially consists of either a straight residue from distillation (which can be of the hard, high melting point type), or as is more common, the “blown” grades which are prepared by partially oxidising the asphalt base by blowing in air.

After the pipe is cleaned, a quick drying primer is applied and allowed to dry. Following this coal tar or asphalt is applied by flooding, during which layers of glass fiber mat and/or felt are drawn into the enamel to act as reinforcement. Total thickness of the finished coating is usually in the region of 5 mm.

The coating system used for the 36” SBHT Pipeline, a 4mm Coal Tar Enamel (CTE) overlaid with a concrete coating system, was the primary coating of choice for most major offshore trunk lines for many years. Coal Tar Enamel systems have been a primary coating system for both onshore and offshore pipelines for over 80 years, however their use has now largely discontinued due to Health, Safety an Environmental (HSE) concerns. In most parts of the world, CTE coating systems were phased out during the 80’s and 90’s. A similar coating system, Asphalt Enamel, is used as an alternative system nowadays, to date without HSE issues being a major concern.

Coal Tar Enamel & Asphalt Enamel coating systems, when combined with a concrete weight coating that provides additional protection and support to the system, have an excellent track record in subsea service . They have operating temperature limitations, whereby they become brittle if exposed to cold temperatures, and for most coal tar formulations, operating above 55-60°C leads to softening and degradation of the coating properties. Many of the pipelines installed in the late 60's with coal tar enamel coatings are still in service today CTE + Concrete coating in general has been shown with time to perform to a very high level. This is evidenced by the fact that the coating breakdown factors now accepted for CTE-Type coating system are significantly lower than was conservatively assumed in the past

CHAPTER 3

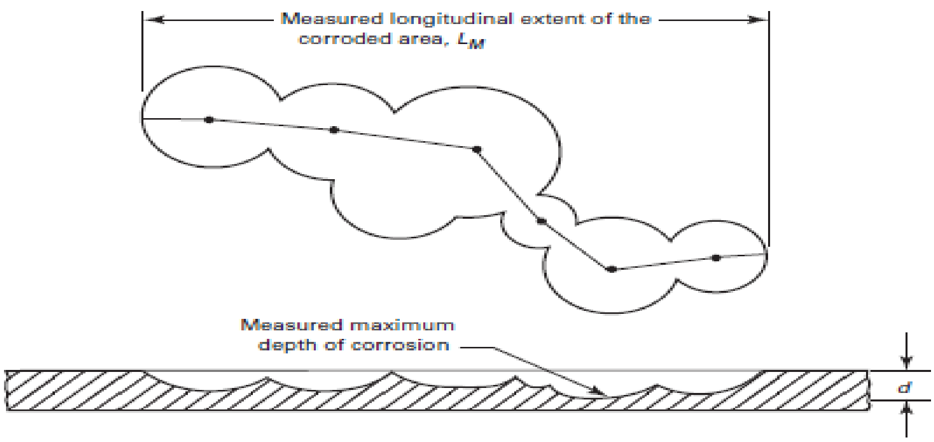
3.0 THEORETICAL DEVELOPMENT:

3.1 CASE1: Mechanical Life Of Pipeline

3.1.1Assessment of Corrosion Defects:

Theoretically, ASME B31G allows determination of the remaining strength of the corroded pipes and estimating of the maximum allowable operating pressure (MAOP). However, it does not provide an proper understanding of the current state pertaining to the corrosion rate that is prevailing in the pipeline .it mainly focus on the remaining strength of the pipeline. So if we could find an method for finding the remaining life of the pipeline with the existing environmental conditions and the corrosion rate how much the pipeline will run for the current operating cycles . this has a major advantage of removing the need for continuous monitoring for the operator and allow for timely restoration of the pipeline. This could be of great benefits to the operator since it could allow him to plan on the maintenance

Fig:3.1 Defect dimensions



In ASME 31 G there are 3 evaluation methods , as an common and widely accepted practices which is to use the effective area method . Level 2 evaluations are performed using what is known as the Effective Area Method or sometimes the RSTRENG method. Level 2 evaluations shall be carried out using a procedure similar to the ten steps described for Level 1, except that the Effective Area Method generally requires several measurements of the depth of corrosion or remaining wall thickness throughout the corroded area. The Effective Area Method is expressed as follows:

$$S_F = S_{\text{flow}} \left[\frac{1 - A/A_0}{1 - (A/A_0)/M} \right]$$

Where,

S_{flow} = Flow stress of the material (MPa)

S_F = Failure stress levels (MPa)

A= local area of metal loss in the longitudinal Plane.

A_0 = local original metal area = Lt

M = Folias factor

The Effective Area Method evaluates, by iteration, all possible combinations of local metal loss, A, with respect to original material, A_0. It requires for input a detailed longitudinal distribution or profile of metal loss. The detailed profile is established by obtaining several measurements of metal loss or remaining wall thickness throughout the metal loss area. Such measurements may be arranged in a grid pattern, or may follow a river bottom path through the deepest areas of metal loss. Increments of measurement need not be uniform, subject to limitations of application software. If using a grid pattern, the analysis must be repeated along each meridian to establish the governing solution.

3.1.2 Folias Factor:

The Folias factor, M is a measure of stress concentration that is caused by radial deflection of the pipe surrounding a defect.

The M term is given by,

For $l^2/Dt \leq 50$

$$M = (1 + 0.6275(l^2/Dt) - 0.003375(l^4/D^2t^2))^{1/2}$$

For $(l^2/Dt) > 50$

$$M = (0.032(l^2/Dt + 3.3)).$$

Flow strength is the property of the material, which has direct bearing to the yield strength the below relationship gives the actual measure of flow strength. the various flaw assessment methods use different assumptions regarding the critical failure stress. According to ASME B31G, the failure stress in the component σ_F (flow stress) is 1.1 times higher than the yield strength σp of the pipe material. In case of the modified ASME B31G and the RSTRENG,

$$\sigma_F = \sigma_p + 68.95 \text{ N/mm2}$$

(i.e., $\sigma_F = \sigma_p$ + 10000 psi) is used instead. The flow stress, known from fracture mechanics, defines a medium material stressing in the remaining wall above the flaw, which, when exceeded, may cause structural failure of the flaw

$$S_{flow} = SMYS + 68.95 \text{ MPa}$$

where,

SMYS = Specified Minimum Yield Stress

L = axial length of the metal loss

D = specified outside diameter of the pipe

t = pipe wall thickness

In the ASME 31G the area of metal loss is calculated from the length & maximum depth of the corroded region by considering the area o be rectangular. The folias factor also takes into consideration the stress concentration factor around the defect as its depends on the diameter , length & thickness .So substituting the above equation we get,

$$\sigma_F = \sigma_{flow} \, \frac{1-(\frac{d}{t})}{1-(\frac{d}{t*M})}$$

3.1.3 Influence of steady state corrosion on the pipelines:

The rate of corrosion growth in pipeline based on the studies done by southwell shows that the rate of corrosion is found to be high in the initial periods then it gradually steadies .His experiments were conducted on both marine , non-marine and fresh water , the result shows to be complied. The time period for the steady state of corrosion is to be 4- 5 years from the initial period which is depended mainly the environment.

De Waard and Milliams Model:This is one of the most known mechanistic models for predicting CO2 corrosion. This model is based on the electrochemical studies carried out by de Waard and Milliams to show the correlation between temperature (°C), CO2 partial pressure, and corrosion rate (mm/yr). The equation for the CO2 corrosion rate is shown as follows:

$$\text{Log(CR)} = 7.96 - (2320/(T + 273)) - 5.55*10^{-3}\,T + 0.67\,(P_{CO2})$$

Where,

CR =corrosion rate (mm/yr),

T = temperature (°C)

P_{CO2}= CO2 partial pressure (Mpa)

To validate this model we use De waard & lots modelled corrosion rate .Their experimental result is given as follows.

$$1/V_{CR} = (1/V_r) + (1/V_m)$$

$$\text{Log}\,(V_r) = 4.93 - (1119/T+273) + 0.58\,\log(P_{CO2})$$

$$V_m = 2.45\left(\frac{U^{0.8}}{D^{0.8}}\right)P_{CO2}$$

Where,

T = temperature (°C),

P_{CO2} = CO_2 partial pressure (Mpa).

U= liquid flow rate (m/s),

D = hydraulic diameter of the pipe.

The time dependence of the corrosion defect size growth for depth & length of the defects can be assumed to be same. This value of corrosion rate can be used in the following equation ,

$$d = d_o + R(\Delta T)$$

$$L = L_o + R(\Delta T)$$

Where

d_o = is the measured value for depth of the defect

L_o = is the measured value of length of defect

$$\Delta T = (T - T_o)$$

Where,

T_o = is the time in years during the measurement of d_o

T = Total Exposure time

By using the above equations we can clearly note the change of the dimensions of the depth and length of the defects with respect to time as change in length brings about change on folias factor (M).Hence effectively find the failure pressure in future time.

On substitution we get the following equation,

$$P_f = \frac{S}{DF} \, {1-(do+R(T-To)/t} \Big/ {1-(do+R(T-To)/(tM)}$$

Where,

$S = 2(\sigma + 68.5)\, t$

σ = Specified minimum Yield stress in Mpa

t = Wall thickness (mm).

3.2 CASE 2 : Calculation of Anodes life:

The CP system will be designed to provide protection to pipeline for the design life against corrosion in addition to external anti-corrosion will be calculated based on:

Calculation of the number of anodes shall be done to satisfy below mentioned criteria.

3.2.1Total surface area of pipeline (Ac):

$$A_c = \pi \times D_{pipe} \times L_{seg}$$

Where

D pipe = Pipeline outside diameter (m)

L seg = Pipeline section length (m)

3.2.2Current demand calculations (I_c):

The required current to protect the pipeline is calculated based on the total surface area of the pipeline section.

$$I_c = A_c \times f_c \times I_d$$

Where

I_c = Current demand (A)

f_c = Coating breakdown factor

I_d = Current density (A/m2)

3.2.3Initial anode thickness (t_{ai})

$$t_{ai} = t_{conc} - t_{neo}$$

where

t_{ai} = Anode initial thickness (m)

t_{conc} = Concrete weight coating thickness (m)

t_{neo} = Neoprene thickness (m)

3.2.3 Initial anode outside diameter (ODai)

$$OD_{ai} = ID_a + 2t_{ai}$$

Where,

ODai =Initial anode outside diameter (m)

3.2.4 Final individual anode mass (m_{af})

Individual anode mass at the end of pipeline design life is calculated using the utilization Factor:

$$M_a = V_a * \rho_a$$

Where

m_{af} = Final individual anode mass (kg)

3.2.5 Final anode outside diameter (OD af)

$$OD_{af} = ID_a + 2t_{af}$$

Where

OD_{af} = Final anode outside diameter (m)

taf = Anode final thickness (m)

3.2.6 Minimum no of anodes required:

$$N_m = I .(t_F/C_a)$$

Where,

T_F = the design life of the cathode

3.2.7 Maximum required anode spacing :

$$L_{spm} =(L/n_m)$$

3.2.8 Maximum joints for anode spacing required:;

$$\text{Joints} = (L_{spm} /L_j)$$

3.2.9 Anode service life:

$$T_{af} = (L*c\_a)/(I*joints*L)$$

CHAPTER 4

4.0 MODEL INPUT DATA:

4.1 CASE 1:

Table 4.1: Input parameters for case 1

Parameters	Units	Value
Outside Diameter	mm	1066
Nominal wall thickness	mm	28.3
Service	-	Yes
Pipeline length	km	244
Operating Pressure	Mpa	10.58
Partial pressure CO_2	Mpa	0.733

4.2 CASE 2 :

Table 4.2: Input parameters for Case 2

Parameters	Units	Value
Pipeline Length	m	1000
Wall thickness	mm	914.4
Joint Length	M	12.2

Anti-corrosion coating	mm	4
Design life	Years	50
Mean current density	$Amp.m^{-2}$	0.02
Temperature Correction	$Amp.m^{-2}C^{-1}$	0.001
Protection Potential	Volts	-0.9
Environmental resistivity	Ohm.m	0.4

CHAPTER 5

5.0 RESULTS AND DISSCUSSION

5.1 CASE 1:

Initially the residual life of the 42” pipeline with critical defect of d_o = 11.3mm ,L= 95mm was done to and the exposure period was found out to be 2yrs from the current date.

Then for further studies I have considered the average defect depth of 4.99mm and average length of 56mm at corrosion rate of 1.05mm/yr and further conducted analysis for changes in depth of the defect and rate of corrosion at 25% and 50% of current rates the results are given below.

Fig 5.1: Showing the variation for pressure vs life of pipeline.

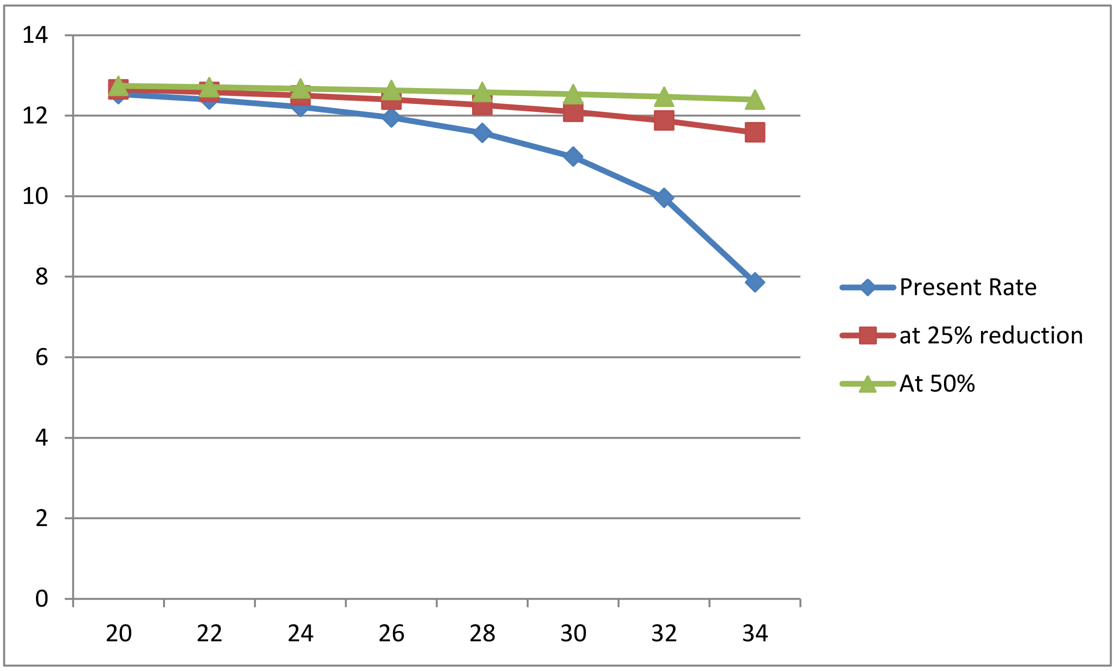
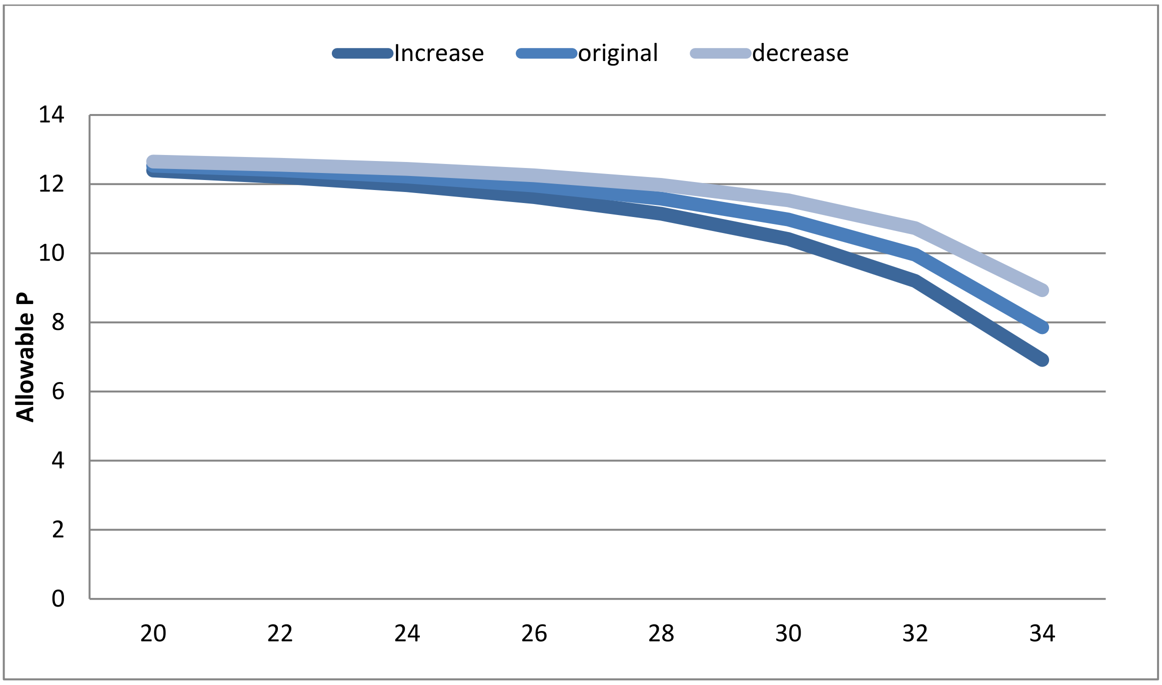


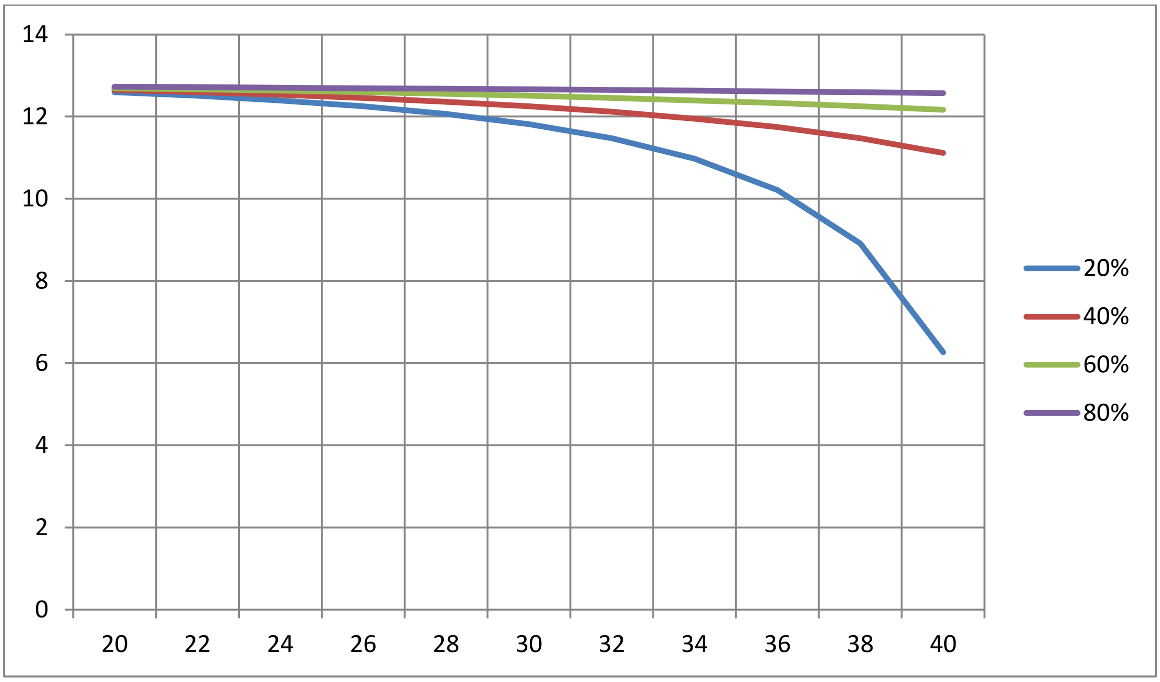
Fig: 5.2: Showing the variation of the allowable pressure vs life of pipeline



Then further went on to change in the length of the defect at an increase and decrease of 25% and keeping all other values at constant. It can been seen that there is no applicable difference in life of the pipeline with change in the length of defect. It's shown in figure as follows:

Then if we can manage to reduce the rate of corrosion by 20%, 40%,60%, and 80% using inhibitors , its effect on the life span of pipline.it shown in figure below.

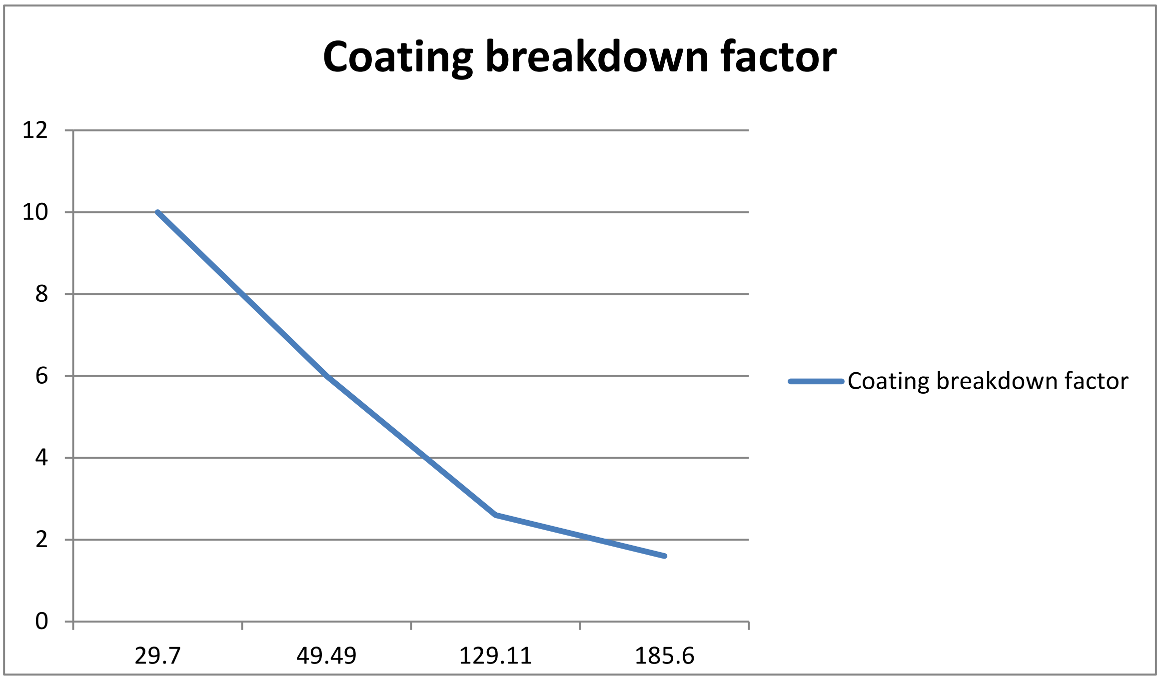
Fig 5.3 : Showing the variation of corrosion rate.



5.2 CASE 2:

In this a relative study of the coating breakdown factors of 36” pipeline is done and its results are discussed.it shows the significant increase in the anode life is seen as there is reduction in the coating breakdown factor decreases. The coating breakdown factor for various cases like 1.6%, 2.3% , 6% ,10%.

Fig 5.4: Coating breakdown variation for anode life at 1.6%, 2.3%, 6%, 10%



CHAPTER 6

6.0 CONCLUSIONS AND RECOMMENDATIONS

36” Pipeline analysis:

In the process of analysing the CP system it’s found that the entire design which was done is over conservative especially with respect to coating breakdown factor used in the system. The effect of coating breakdown factor for the coal tar enamel shows that the with increase in the coating breakdown factor the anode service life which is reducing considerably.

Recommendations: During this study, the original 36” SHBT pipeline CP system design basis was able to be recalculated using known parameters and the accepted standards at the time that the line was designed. This has confirmed a 25 year CP system design life, using the original design factors, which has validated the assumptions that were made in the design calculation (such as coating breakdown factors).

However, when reviewing the expected CP system and coating performance based on the best practice now available, using knowledge gained over the last 25 years of pipeline operation and using the current CP design standards, it is clear that the original CP system was very conservatively designed (overdesigned).

Provided the original coating and CP system was not significantly damaged during the construction and installation process, (this is considered an unlikely scenario given the CP measurements and the In-Line Inspection data available), then it is expected that the CP system and external coating of this line should continue to protect the pipeline for another 25 years of operation. Based on the expected ability of this pipeline to continue in service for an additional 25 years, and the significant cost differential between the new pipeline option and the anode retrofit option(considered a very unlikely requirement), it is the finding of this study that the existing 36” SBHT pipeline should be considered for continued service for a further 25 years. Note that this conclusion is based on the information available at the time of this review as indicated .

In order to provide confidence to support this finding (in light of the limited and flawed CP system survey data available), an additional and more comprehensive CP system survey should be conducted, as outlined in the recommendations section.

While the internal corrosion appears to be relatively well managed due to the low dew-point of the gas, there is evidence from the retrieved black ferrous product, supported by the 1997 and 2009 inline inspection results, that internal corrosion on this line is potentially a threat moving forward for an extended pipeline life. Provided that the internal corrosion can be managed and monitored at the same level or better than the existing practice, the evidence available to date indicates that continued operation for a further 25 years without compromising the fitness for purpose of the pipeline or its ability to operate safely, is entirely achievable.

The internal corrosion threat is considered to be a more significant (but still manageable) threat to the integrity of this pipeline into the future than the external corrosion, as the external corrosion rates and risks will be progressive, and provided the CP system is monitored, sufficient time will be available to pro-actively mitigate against any external corrosion threats. However, the internal corrosion threat requires continual monitoring and management of the internal condition. One significant upset, such as significant water ingress into the pipeline, could increase the internal corrosion threat, with an associated increase in corrosion rate. This threat would not be eliminated by the installation of a new pipeline. Should it be found that the CP system is in poor condition either locally or globally, then the retrofit of anode sleds are a cost effective, tried and tested means of extending the pipeline operating life.

There are many examples provided in this study of anode skid retrofits (including friction stud weld connections) being installed on live pipelines, including live gas pipelines. If there are any areas where anodes are more likely to be depleted, this would be expected to be at locations where there may be drain from other sources, such as the PLEM, other pipeline tie-ins, the shore crossing, or areas of local coating damage.

It should be noted that if the pipeline duty changes (e.g. changed flow rates, contents, temperature), then a review should be performed to assess the impact on the overall pipeline integrity (e.g. the CP system and coating system have limited high temperature capacity, and will be compromised for extended operations above 50°C).

Internal Corrosion Threats: As the latest in-line inspection and the 1997 in-line inspection indicate that internal corrosion is present, then continued diligence shall be placed on the monitoring and control of the internal corrosion threats for this line, including management of upset conditions, dew pointing, and onshore sampling and monitoring, operational pigging, and engineering review of the findings of this operational pigging. While internal corrosion has been experienced in the past, possibly from upset conditions in the line, it is important to note that there is still significant wall thickness remaining in the line to ensure fitness for service, provided the appropriate internal corrosion controls are put in place. The most severe defect reported in the 2009 ILI was 29% wall loss. The pattern of the corrosion features reported by the ILI being predominantly in the bottom quadrant of the pipeline is clearly indicative of internal corrosion where liquids (water) at the bottom of the pipeline has lead to CO_2 (acid gas), however, the internal corrosion to date does not appear severe, with only 20 features reported greater than 14% wall loss, to a maximum of 29%.

In order to ensure the future fitness for service of this line, the following tasks should be considered as part of the overall corrosion management strategy:

- Continue to provide a high level of control over input gas quality (dew point control). Any upset conditions that allow liquid water or 'wet' gas to enter the line should be fully reviewed through a root cause analysis, and actions put in place to ensure that this does not happen again, and 'dry' gas should be re-introduced to the line as quickly as possible to allow absorption of any condensed water. Provided the line is able to be maintained fully dry, no further corrosion is expected. Upset conditions have been reported in the past .

- Continue to maintain routine (annual) cleaning pigging operations, and assessing the composition and amount of any received product. This provides additional information to demonstrate the quality of the gas dew pointing and inlet fluids control. More frequent pigging should be considered if upset conditions have been experienced.

- Routine sampling from onshore separator (suggest monthly) liquids stream to assess composition of liquids stream, detect any produced water, and determine iron-counts from the received liquid. The iron counts should be routinely plotted to identify any upset conditions or trends.

- Continue to perform periodic / routine in-line inspections using MLF tools, suggested frequency every 5 years, depending on the consistency of the dewpoint controls, and the results of routine cleaning pigging. For example, if upset conditions are experienced allowing water into the line consistently, and there is evidence of corrosion product in the annual pigging operations, then the ILI inspection should be prioritised, and the inspection interval decreased. If, however, consecutive pig runs show no change, and dewpoint control is good, then consideration may be given to increasing the ILI interval.

Anode retrofits: In the unexpected case that some of the CP system (anodes) are more depleted than expected (e.g. due to a local drain from a tie-in pipeline), then it may be required to consider further the rectification option of local anode supplementation. This will depend on the outcome of the CP surveys. Retrofits using a connected anode skid (preferably friction stud welded) should be considered, following a detailed engineering review.

In-Line Inspection Due to the criticality of the line, ongoing in-line inspections should be conducted, with a recommended interval of at least every 5 years moving forward to provide ongoing operational assurance of the fitness for purpose of the line, and detect any significant changes to the condition of the line, allowing mitigation to be undertaken in a timely fashion.

Service Change: Any change of service or duty (e.g. temperature, operating pressure, fluid types) for this pipeline into the future should be considered in light of the constraints of the pipeline (e,g., operating temperature limits of 50°C for the zinc anodes and requirement for internal corrosion management).

42” Pipeline analysis:

As the analysis for the results in the previous section, shows that the pipeline will be critical after 2 years of usage, in this analysis no external loads and other variable factors have been taken in to account.

The outcomes of the analysis study prepared, show that variation of life to the different parameters are non-linear. In the first case with decrease in the thickness of the defected area the failure pressure will reduce with the increase in exposure period.

This also shows that it can be used beyond a certain time safely but, there is a failure pressure that keeps reducing quite steeply hence we have to assess the safety of the pipeline before any further utilizing it at normal operating pressure. If it's found that it's not safe to use then the pipeline has to be abandoned or can be used further by reducing the operating pressure.

On experimenting with various parameters like depth, length and rate of corrosion of the pipeline it seems that some of them have a lighter effect on the increase in the exposure period. But parameter like the depth of the defect has an higher influence on the life period of the pipeline, as a 25% reduction in the depth the defect shows significant increase in the life of the pipeline .And the effect of corrosion decrease by 30% - 40 % will also result in, a way such that it will drive the pipeline for further more years, without any glitches. The recommendations to be followed for 42" Pipeline is also same as given above in 36"Pipeline.

CHAPTER 7

7.0 REFERENCE

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APPENDIX 1

CASE 1

CORROSION MODEL:

$Log(CR) = 7.96 – (2320/\ \ T+273 – (5.53 \times 10^{-3} \times T)+ 0.67 \log(P_{co2})$

$P_{CO2} = n \times P_{CO2}$

$=(6.93 \times 10.58/100)$

$=0.733MPa$

$Log(CR)= 7.96 – (2320/29+273) – (5.55 \times 10^{-3} \times 29)+0.67\log(0.73)$

$= 0.277 + \log (0.733) \times 0.67 – (2320 / 29+273)$

$= 0.1169 + 0.67 \log (0.7331)$

$CR \quad = 1.053mm/yr$

Checking the model:

$1/V_{CR} = (1/V_R) + (1/V_M)$

$Log (V_R) = 4.93 - (1119/(T + 273)) + 0.58 \log (P_{CO2})$

$= 4.93 – (1119 /29 + 273) + 0.58\log (0.733)$

$=1.244 + 0.58 \log (0.733), V_R = 13.59$

Corrosion rate= 1.05 mm/yr

$P_A = 10.58Mpa$

Diameter = 1.06 m

S_y=415Mpa

D_o =11.3×10^{-3} m

T =28×10^{-3}m

L = 95×10^{-3}

R_C = 1.05mm/yr

Z = $(L^2 /Dt) = 0.014$

M = $(1 + 0.6275 (Z) -0.003375 Z^2)^{0.5}$

$= (1+0.6275 (0.14) – (0.003375\times0.014^2))^{0.5}$

$= (1.00878 – 6.615 \times 10^{-7})^{0.5}$

= 1.004

P_a= $(2 \times t /D \times F)$ (Sy+ 68.95) $((1 - (do + Rc(\Delta T))/T/1 - (do + Rc(\Delta T))/T \times M))$

$10.58 = (2 \times 28.3 \times 10^3(415 + 68.95)/2 \times 1.06)$

$\times ((1 - (11.3 \times 10^{-3} + 1.05 \times \Delta T)/t/(1 - (11.3 \times 10^{-3} + 1.05 \times \Delta T)/tM$

$=(0.0566 \times ((415 + 68.95)/1.06 \times 2)(\frac{1-(11.8\times10^{-3}+1.05\times10^{-3(\Delta T)}/t}{1-(11.8\times10^{-3}+1.05\times10^{-3(\Delta T)}/tM})$

10.58 = 12.99

$$\left(\frac{1-(11.3\times10^{-3}/28.3\times10\text{^}-3)+(1.05\times10^{-3}\times\Delta T)/28.3\times10\text{^}-3)}{1-(11.3\times10^{-3}/28.3\times10\text{^}-3\times1.004)+((1.05\times10^{-3}\times\Delta T)/28.3\times10\text{^}-3\times1.004)}\right)$$

0.818 = $((0.601-(0.037\times\Delta T)/\big(0.603-0.037\ (\Delta T)\big)$

0.818 = (0.601 – 0.037× $\Delta T) = \ \ (0.601-0.037(\Delta T))$

$$\Delta T = 2yrs$$

APPENDIX 2

CASE 2

CATHODIC PROTECTION : ANODE LIFE

Length of pipe = 1000m

Wall thickness =28.575 $\times 10^{-3}$ m

Diameter = 914.4 $\times 10^{-3}$ m

Joint Length = 12.2 m

Temperature = 43^{o}C

Mean density = 0.02 amps.m^{2}

Temperature correction = 0.001 amp.m^{-2}.C^{-1}

Mean breakdown factor:

1) ISO 15589.2 - 25 yrs -1.6 %

2) ISO 15589.2 - 50 yrs -2.3 %

3)WWTS PL -50 yrs – 6.0%

4) Actual Design - 10%

Steel protection Voltage E_c = -0.9 V

Environmental resistivity ρ = 0.4 Ω.m

ANODE DATA:

Inner Diameter = D + 2t_c =992mm

Anode Thickness t_a = 70mm

Length =512mm

Half shell gap = 100mm

Anode material =7140 kg.m^{-3}

Anode utilization factor = 0.8

Anode capacity Ɛ =580amp.hr.kg^{-1}

Surface area of anode $= (\pi(D + 2t) - 2g) \times L)$

= 1.606m^2

Cross sectional area of anode = $(\pi(ID + t) - 2\, g_a)t$

= 0.204 m^2

Volume of anode $V_a = A \times L_a$

= 0.204 ×512

= 104.571 L

Net mass per anode $M_a = V_a \times \rho$

$= 104.5 \times 7140 \times 0.001$

$= 746.3$ kg

Surface area to be protected $A_{CM} = \pi DL$

$= \pi \times 922 \times 1000$

$= 2.873 \times 10^3 \, m^2$

Current demand for the area $I_{CM} = A_{CM} \times f_{Cm} \times t_f$

1) =1.747amps
2) =2.571amps
3) =6.915amps
4) =10.915amps

Anode current capacity $C_a = M_a \mathcal{E}_u$

$= 746.637 \times 580 \times 0.8$

$= 3.464 \times 10^5$ amp.hr

Anode service life $t_{af} = \frac{L.Ca}{I.n.Lj}$

1) 185.6 yrs
2) 129.11yrs
3) 49.49 yrs
4) 29.7yrs