DEVELOPMENT OF A COMPUTER PROGRAM FOR THE PREDICTION OF COATING DEFECT AREA IN OIL AND GAS PIPELINES

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CERTIFICATION

I certify that this research project was carried out by OLANIRAN, OLADAYO at the department of Metallurgical and Materials Engineering, Federal University of Technology Akure, under our supervision and it has not been submitted elsewhere for the award of a degree.

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DEDICATION

This thesis is dedicated to the loving memory of four very special people. My father, Mr Sam. A. Olaniran, my lovely brothers, Sunday Olaniyi Olaniran, Olawale Olalere Olaniran and Olatokunbo Olawumi Olaniran. I only wish they all could have lived to see this day perhaps, William Shakespeare was right when he said: "Whence comfort seems to come, discomfort swells" Rest in peace loved ones. I love you but God loves you more.

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"----------continue thou in the things which thou hast learned and hast been assured of knowing of whom thou hast learned them." ***II Tim 3:14***

ABTRACT

The study was to investigate the corrosion characteristics of pipelines in different oil and gas installations at NNPC, Shell Petroleum Company and Chevron Petroleum Company. Parameters affecting pipeline degradation and coating defect area were measured and these include: diameter of the pipeline, applied current, coating thickness, leakage resistance, potential gradient, soil resistivity and depth of burial of pipelines.

A data-driven non-linear regression model was developed between coating defect area(s) as a dependent variable and coating thickness (tc), leakage resistance (Cr) burial depth as independent variables. A similar model was developed between potential gradient (E) and coating defect area (S), coating thickness and burial depth. Based on the derived equations, a computer program (CODEAP) was developed using a q-basic programming language to simulate coating defect area in pipeline installations of the selected oil companies

The models were used to predict the coating defect area of various pipelines as well as the relationship between: coating thickness (tc) and coating defect area (S), coating thickness (tc) and potential gradient (E), coating defect area (S) and potential gradient (E) and leakage resistance (Cr) and potential gradient (E) at various burial depth and applied voltages using validating data. Those relationships were further presented graphically.

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"I find the great thing in this world is not so much, where we stand as in what direction we are moving (except the path we are taking). To reach the part of heaven, we must sail sometimes with the wind and sometimes against it – but we must sail and not drift nor lie at the anchor".

Oliver Wendell Holmes (1809-1894)

CHAPTER ONE

INTRODUCTION

Buried pipeline are exposed to corrosive soil environments and the stray currents of direct-current railway, and are protected against corrosion by protective coating or protective coating combined with cathodic protection (Suzuki et al, 1990). Once the pipeline is buried, its protective coating is often liable to damage by construction works near by. Corrosion being a deterioration of a material resulting from chemical attack by its environment (Smith, 1990), result in weakness of the steel pipe thereby making it easier and susceptible to vandalization, thereby leading to spillage. More importantly, vandalization and failures may present a hazard to platform personnel, and if failure leads to ignition of oil or gas on the installation, the consequences may be catastrophic with total loss of the installation and loss of life as recorded in some parts of Nigeria in the recent time. Oil spillage, as an aftermath of failure, spreads rapidly on the seawater, thereby affecting life especially fishes and seabirds, rendering seawater inhabitable and unexploitable, reducing seawater activities by man.

Investigation and data collection show that corrosion is the most frequently recorded failure mechanism leading to oil spillage. There is therefore a serious need for preventive measures to be carried out against corrosion on installation. According to the wall sheet journal, cost of corrosion loss to oil and gas producers are enormous. The cost is further increased because of deeper wells and more hostile environment and higher temperatures and corrosive sulphur gases (350^0C & H_2S). The petroleum industries spend million dollars per day to protect underground pipes and oilrigs. As direct or primary corrosion cost, we count cost for anti corrosive painting or other protection methods, the exchange of corroded equipment, which for other reasons could have been used longer. The use of expensive metals instead of carbon steel etc.. In addition, we have indirect or secondary costs e.g. as a result of shutdown in industries.

One would wonder why this material fails in service; it could be due to one of these reasons:

a. Abuse (including natural catastrophes)

b. Design deficiency

c. Material problem

d. Service condition

e. Operators condition

f. Environment

As it is widely acknowledged, it is easier and cheaper to tread the path of preventive measure rather than repair or replace failed equipment in a plant. Corrosion control on offshore oil production installation has become a matter of increasing importance and so deserves the appropriate attention to the economic consequences that will arise from its neglect.

In the recent years, most attention has been focused on the development of pipeline maintenance techniques. A simple high performance coating defect inspection technique (trade name the super coating defect inspection system and abbreviated SUPER CODIN) was developed by Zusuki, (1990).

Pipeline maintenance demands an early and accurate detection of external corrosion of buried steel pipe. Corrosion control therefore requires advanced technology and enormous efforts.

The conventional method of excavation poses many problems (excavation cost, inspection limited to the range of excavation, traffic congestion resulting from the excavation work.

A system was thus developed whereby loss of wall thickness due to external corrosion can be detected from inside the buried pipeline. A model was developed and used in simulation calculations. To validate its performance, the model was tested on a pipeline simulating an actual pipeline in service.

The test results demonstrate that the model satisfies the requirement of detection performance.

1.2 OBJECTIVES OF THE STUDY

The objectives are to:

1. Evaluate the corrosion characteristics of coated pipeline in some oil and gas installation
2. Develop a computer program for the prediction of coating defect area for oil and gas pipelines
3. Validate the developed program with actual data

1.3 CONTRIBUTION OF RESEARCH TO KNOWLEDGE

The research presented a mathematical model with a computer program that will enhance system performance monitoring by predicting the extent of surface defect area of pipeline coatings. This will help in accurate and timely prediction of coating defect in oil and gas production installations forestalling pipeline leakage and breakdown.

1.4 JUSTIFICATION

Offshore oil production spillage are not only caused by vandalization but also by wrong application of technology. It is easier and cheaper to tread the path of preventive measure rather than replace failed equipment in the plant.

CHAPTER TWO

LITERATURE REVIEW

2.1 CORROSION

Corrosion is a chemical reaction of a metal with its environment as a result of which electric current flow. The environment could be aqueous or non aqueous. Many corrosion reactions occur in what can be considered as dry environment. Corrosion can occur in the atmosphere where the presence of water vapour condensing on a solid surface, together with an ionic material from any available source, is enough to cause corrosion for the same reasons as if the metal were immersed. (Tretheway and Chamberlain 1995)

2.1.1 OXIDATION – REDUCTION REACTION

Corrosion reactions are electrochemical in nature, it is important to understand the basic principles of electrochemical reactions. A piece of steel metal when placed in a beaker of dilute hydrochloric acid, the steel dissolves or corrodes in the acid, and iron chloride and hydrogen gas are produced as indicated by the chemical reaction.

$$Fe + 2HCl \rightarrow FeCl_2 + H_2\uparrow \text{ ----------(1)}$$

This reaction can be written in a simplified ionic form, omitting the chloride ions as

$Fe + 2H^+ \rightarrow Fe^{2+} + H_2\uparrow$ ----------(2)

This equation consists of two half-reactions: one for the oxidation of the iron in the steel and other for the reduction of the hydrogen ions to form hydrogen gas. These half-cell reactions can be written as:

$Fe \rightarrow Fe^{2+} + 2e^-$ ----------(3) (oxidation half-cell reaction)

$2H^+ + 2e^- \rightarrow H2$ ----------(4) (reduction half-cell reaction)

Electrochemical corrosion reaction involves oxidation reaction that produces electrons and reduction reaction that consume them. Both oxidation and reduction reactions must occur at the same time and same overall rate to prevent a build up of electric charge in the metal. The disposition of the reaction product is often decisive in controlling the rate of corrosion (Tretheway and Chamberlain, 1995). They go into solution or are evolved as a gas and thus, not inhibit further reaction. In other case, an insoluble compound is formed that may cover the metal surface and be effective in reducing the rate of additional corrosion (PASIVATION)

2.1.2 POLARIZATION

The anodic reaction (the dissolving electrode) rises in potential when a current is drawn from the equilibrium potential. The cathodic potential fall from its equilibrium potential when a current is drawn from

the equilibrium (fig 2.1). The extent of this potential difference when measured in volts is termed POLARISATION (Tretheway and Chamberlain, 1995).

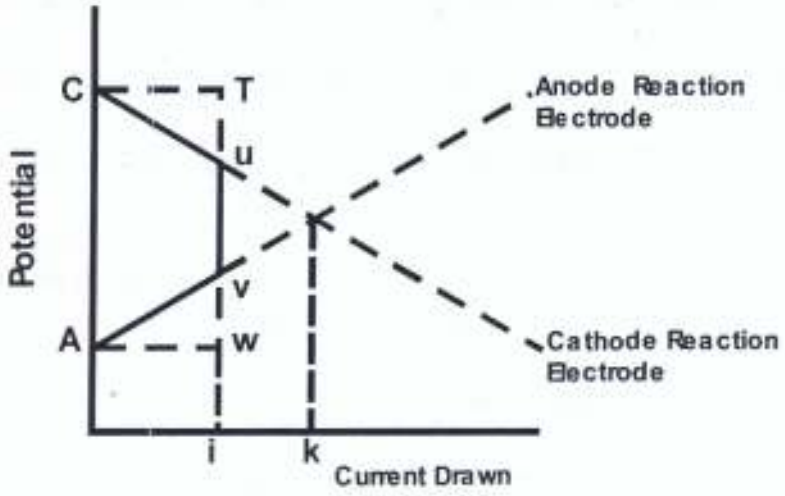


Fig:1 Polarisation of an electrochemical anodic and cathodic reaction.

Representing the anodic potential and cathodic potential by A and C, the external potential difference measured for a current I flowing is UV. The open circuit potential AC has dropped owing to a voltage drop across the cathode environment of 'TU' and anode environment of 'VW', making a total potential drop across the internal resistance of TU + VW. These potential drops are referred to as POLARISATIONS. Thus 'TU' represents the cathodic polarization and VW anodic polarization.

2.2 ELECTROCHEMICAL CORROSION RATE MEASUREMENT

Corrosion rate is the speed with which corrosion takes places in a particular metal with respect to time. The expression mills per year is the most desirable unit of expressing corrosion rates and it is readily calculated from the weight loss of the metal specimen during the corrosion test by the formula given below (Scully, 1990).

$$mmpy = \frac{534N}{DAT} \quad \text{----------(5)}$$

Where N = weight loss (mg)

D = density of specimen ($glcm^3$)

A = area of specimen (sq – in)

T = exposure time (hr)

In faraday's law, the rate of metal weight loss, which can be expressed in millimeters per year (mmpy), is directly proportional to current flow from the metal in the electrolyte. Thus,

$$mmpy = \frac{3.15 \times 10^7 \ ZI}{nfD} \quad \text{----------(6)}$$

Where: Z = atomic weight (gm/mole) of the metal (56 for steel),

n = electrical equivalents (2 = iron-ferrous-iron reactions)

F= faraday's constant (98,500 coulombs per equivalents)

D = density (gm/mm^3), I = current density (A / mm^2)

Mixed Potential theory forms the basis for the electrochemical methods used to determine corrosion rate. These are TAFEL

extrapolation and LINEAR polarization techniques. Mixed potential theory, postulated by Wagner and Trand in 1938 states that:

1. Any electrochemical reaction can be divided into two or more partial oxidation and reduction reactions
2. There can be no net accumulation of electrical charge during an electrochemical reaction.

2.2.1 TAFEL EXTRAPOLATION

This technique uses data obtained from cathodic or anodic polarization measurements. Cathodic polarization data are preferred since, these are easier to measure experimentally.

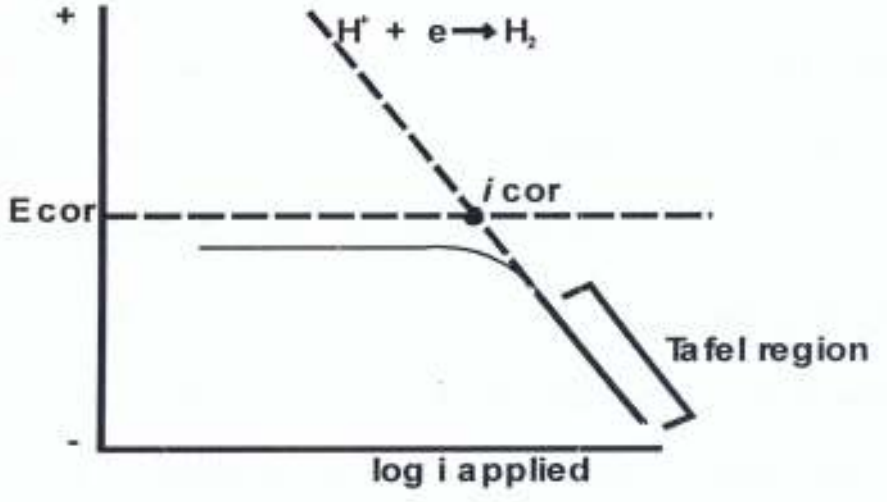


Fig 2: Applied current cathodic polarization curve of a corroding metal showing Tafel extrapolation

Considering the result obtained during the cathodic polarization of a metal m immersed in an air-free acid solution prior to the application of cathodic current, the voltmeter indicates the corrosion potential of the specimen with respect to the reference electrode. If the potential of the electrode is plotted against the logarithm of applied current, a curve shown above is obtained. The curve is non linear at low current, but at higher current (Fontana, 1986), it becomes linear on a semi logarithmic plot. In actual practice, an applied current polarization curve becomes linear on a semi logarithmic plot at approximately 50mv more active than corrosion potential. This region of linearity is referred to as TAFEL REGION. To determine the corrosion rate from such polarization measurement, the Tafel region is extrapolated to corrosion potential. At the corrosion potential, the rate of hydrogen evolution is equal to the rate of metal dissolution, and this point corresponds to the corrosion rate of the system expressed in terms of current density.

Under ideal conditions, the accuracy of Tafel extrapolation method is equal to or greater than conventional weight-loss methods with this technique, it is possible to measure extremely low corrosion rates and it can be used to continuously monitor the corrosion rate of a system.

2.2.2 LINEAR POLARISATION

The disadvantages of Tafel extrapolation method such as the difficulty in achieving reasonable accurate Tafel region due to interference from many extraneous effects and the inability to obtain only one reduction process can be largely overcome by using linear polarization analysis (Ross, 1977)

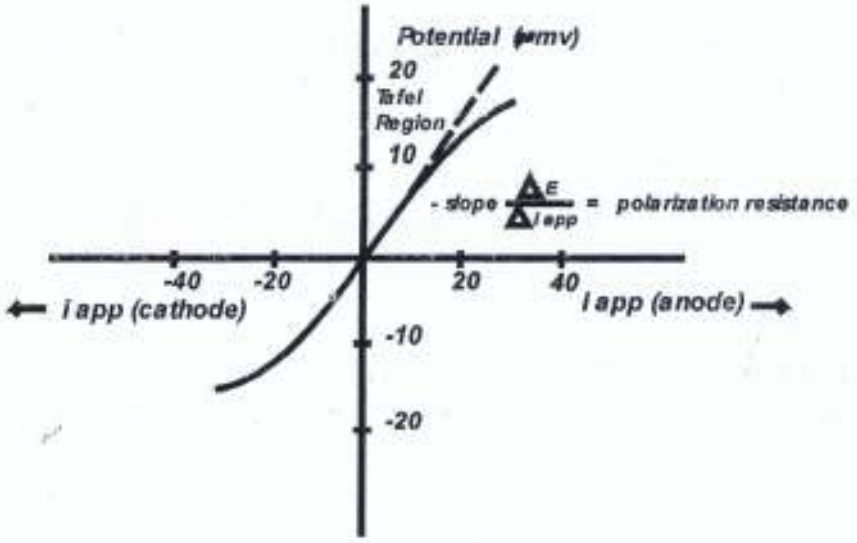


Fig 3: Applied current – linear polarization curve

Within 10mv more noble or more active than the corrosion potential, it is observed that the applied current density is a linear function of electrode potential as illustrated above. In this diagram, the corrosion potential is used as an over voltage reference point and a plot of over voltage versus applied anode and cathodic current is shown on a

linear scale. This plot represents the first 20mv polarization of the curve shown in the diagram above. The slope of this linear-polarization curve is related to the kinetic parameters of the system as follows (Scully, 1990)

$$\frac{\Delta E}{\Delta i \text{ app}} = \frac{\beta a \beta c}{2.3(i \text{ cor})\, \beta a + \beta c} \quad \text{----------(7)}$$

Where βa and βc are the Tafel slopes of the anodic and cathodic reactions respectively. The term $\frac{\Delta E}{\Delta i_{app}}$ is known as the "POLARISATON RESISTANCE and is given in ohms or volts / amperes. If the beta values for the reaction are known, corrosion rate may be calculated by substitution into the equation.

2.3 FORMS OF CORROSION IN OFFSHORE

Rusting of ordinary carbon steel is the most common type of corrosion. Other forms of corrosion that can occur on offshore structures are considered below.

2.3.1 CARBONDIOXIDE RELATED CORROSION FAILURE

If corrosion references are analyzed separately, it becomes apparent that the corrosion problems related to carbondioxide in the produced fluids (crude oil) have been a major source of failure in the production equipment pumps and tubular production pipe work between the well head and the separation vessels themselves.

The corrosive effects of carbonic acid, produced by the dissolution of carbondioxide gas in water phases cause the problems.

$$CO_2 + H_2O \rightarrow H_2CO_3 \text{ ----------(8)}$$

The overall corrosion reaction is represented by

$$Fe + H_2CO_3 \rightarrow FeCO_3 + H_2 \text{ ----------(9)}$$

The reaction rate is affected by temperature, pressure, PH, water composition and the velocity of the fluid, and although the non carbonate corrosion product formed may give some protection to the steel. This is removed at regions of high turbulence or velocity, producing a form of square sided deep pitting, often linear in nature, known as 'mesa type' corrosion (Fontana). This form of corrosion if often seen on the sides of down hole production tubing particularly upstream of joints and can produce what appears externally as random perforations sites of CO_2 corrosion (sweet corrosion).

2.3.2 HYDROGEN SULPHIDE RELATED CORROSION

The effect of hydrogen sulphide, either as a product of the formation or more directly due to the action of sulphate reducing bacteria (SRB), have been noted in all areas of the production system from the down hole equipment, through to the crude oil storage and export system (McCaslin, 1987)

It was deduced that SRB action was producing H_2S and the evolution of hydrogen during subsequent corrosion reaction was resulting in hydrogen embrittlement of the wire.

$$Fe + H_2S \rightarrow FeS + 2H \text{ ----------(10)}$$

Failures due to SRB activity have been noted in stagnant drain lines, in crude oil export system and in low parts inside inter storage tank transfer lines. Sulphide corrosion of non-ferrous component has also been observed. (Sour corrosion).

2.3.3 PITTING CORROSION

Pitting is a form of localized, non-uniform attack in which small areas of the surface are corroded with penetration of the alloy at these areas are usually proceeds in otherwise undamaged metals (Fontana, 1986). A deep-isolated hole caused by pitting is especially difficult to avoid, but improving the homogeneity of the metal and of the corroding medium is often helpful.

2.3.4 EROSION CORROSION

Erosion-corrosion is a form of accelerated attack on the alloy which is caused by the movement of seawater bringing about mechanical action i.e. erosion as well as corrosion arising from its electrochemical nature. It leads to the mechanical removal of protective films from the

surface of alloys and even removal of the metal itself if abrasive particles are entrained in the water (John, 1986).

Generally, the rate of attack increases with velocity of seawater. The effect may be general or localized, producing a grooved appearance and may have a pattern resulting from the direction of flow.

2.3.5 GALVANIC CORROSION

Galvanic corrosion is a type of corrosion that occurs because two dissimilar metals are in contact. It is the type of corrosion that is accelerated by the presence of electrically connected dissimilar metals (Fontana, 1986). Corrosion of the less corrosion-resistant metal is decreased. The less resistant metal becomes anodic and the more resistant metal cathodic and it corrodes very little or not at all in this type of couple.

2.3.6 CREVICE CORROSION

This is an intensive localized corrosion occurring within crevices and other shielded areas of metal surfaces exposed to corrosives. This attack is usually associated with small volumes of stagnant solution caused by holes, gasket surfaces, lap joints, surface deposits and crevice under bolt and rivet heads.

2.3.7 STRESS CORROSION

Stress corrosion refer to greatly accelerated corrosion that takes place in certain environments which metal contain internal tensile stresses. It is an unexpected failure that occurs repeatedly (Scully, 1990). A metal chosen for its corrosion resistance in a given environment is found to fail at a stress level well below its normal fracture stress. Rarely is there any obvious evidence of an impending failure, and because it can occur in component which are apparently unstressed, it is even more of a surprise even component are found defective.

Problems with pipes and tubes are due to hoop stresses, which result from the fabrication processes. Stress relieving heat treatments are thus a vital part of the control of SCC.

There is no single mechanism of SCC. A combination of significant factors may contribute to a given SCC failure. The main features of SCC are:

a. The requirement for tensile stress is beyond doubt. Environment sensitive cracking is the synergism of stress and corrosion; the absence of either eliminates the problems. The stress can be applied directly during the operational lifetime or it can be present in the component as a result of fabrication or installation process.

b. Alloys are generally more susceptible to SCC than pure metals except CU.

c. In the absence of stress, alloy is usually inert to the same specie in the environment, which would lead to cracking.

Stress corrosion is the cracking of metal under the combined effect of tensile stresses and a corrosive environment. Stress corrosion cracking is distinct and different from cracking caused by hydrogen embrittlement.

This corrosion cracking progresses in a direction perpendicular to the existing tensile stress (Peterson, 1991). The source of the stress is immaterial; it could be applied, residual from a welding or thermal. Almost no physical evidence of the formation of SCC will be visible, since the cracks are very fine until in the latter stages.

A common pit on the metal acts as a stress raiser. Corrosion at the pit of the node causes the SCC to start there. The corrosion is highly localized, and the failure looks like a brittle fracture. SCC is prevented by cathodic protection.

SCC plagues the oil industry where pipes in deep high-pressure wells require the use of high strength steels, which are known to be susceptible to SCC, particularly in the presence of H_2S.

2.4 CORROSION PREVENTION AND CONTROL

The magnitude of the monetary investment required to place an offshore platform in the ocean makes control of corrosion mandatory.

The overall corrosion protection system can represent as much a 10% of the total platform cost (Aruckiasamu, 1991).

In view of the fact that corrosion results from a reaction are interaction of a metal or alloy with its service environment the basic control methods are concerned with the treatment of the environment or selecting suitable resistant alloys,for durable applications.

a. The use of coatings (metallic or organic)

b. Selection of alloy that can resist a particular environment

c. Treatment of the environment with suitable chemicals (inhibitors)

d. Cathodic protection

2.4.1 COATINGS

Protection for periods varying from hours to years may be obtained by the formation of a surface layer, which is impervious to water, oxygen, and likely atmospheric contaminants by coatings (Liewellyn, 1992). The basic concept is simply to isolate the steel component or construction from the environment.

Example of coatings include non-metallic coatings (paints, porcelain, plastics, rubbers, bituminous coatings for protecting underground pipes and tanks), chemical coatings (anodic, chromate, phosphate coatings), metallic coatings (zinc, aluminum, cadmium) and greases together with additional materials such as wrapping tapes and grease paints which are used for special situations.

These coatings are applied by brushing, spraying, especially after surface blast cleaning and by hot dipping and cladding.

2.4.2 COATING APPLICATION

Before blast cleaning and application of the coating system, the pipe surface shall be free of all surface contamination oil, grease and other contaminants removed by detergent before blast cleaning (Smith, 1990). Salt contamination, chemical cleaning agents and remaining detergents are washed off using potable water.

PRE-TREATMENT PRIOR TO APPLYING COATINGS

Chemical and mechanical pre-treatments are given to surfaces before coating either to remove existing natural oxide films, corrosion products, or tarnish, or to remove factitious coatings such as protective oils and greases or oxide films produced by heat treatment and manufacturing processes (Higgins, 1993)

REMOVAL OF GREASE AND ORGANIC CONTAMINANTS.

In general these contaminants will be oils or greases applied to assist deformation. Where processes involving the use of large forces such as extrusion have been used; this grease may sometimes be carbonized and burned on to the surface.

Oil and grease solvent such as white spirit, paraffin, and chlorinated hydrocarbons are widely used to prepare surfaces for further treatments (Moore, 1991). The method employed range from wiping over with a solvent-soaked rag, through dipping into tanks of solvent, to degreasing by immersion in chlorinated hydrocarbon vapour and / or boiling liquid chlorinated hydro-carbons

The solvent reservoirs quickly become loaded with dissolved oil and grease which is in turn transfer back to the surfaces to be cleaned. immersion degreasing is best carried out using two tanks on the counter - flow principle (fig 2.4).

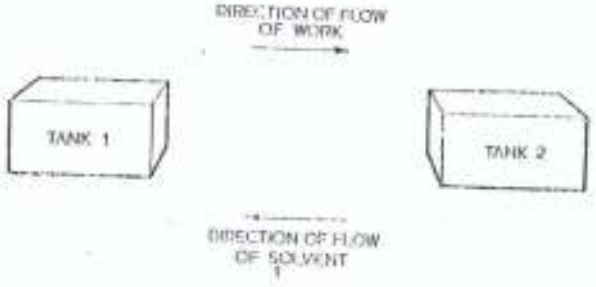


FIg. 4 Counter flow principle of cold immersion solvent degreasing.

VAPOUR DEGREASING. The equipment for industrial use (Fig 2.5) consists in essential of a tall vessel, usually constructed of galvanized sheet or plate. The bottom acts as a sump in which the liquid can be

boiled. Above the liquid level is placed a wire or perforated metal grille on which work can be rested so as to be in the middle zone between the liquid and the condenser coils. The sump can be heated by any convenient method such as gas, oil, steam, high- pressure hot water, or electricity. Both the sump and the cooling coils are fitted with thermostats to limit the maximum temperature of the liquor and the cooling water.

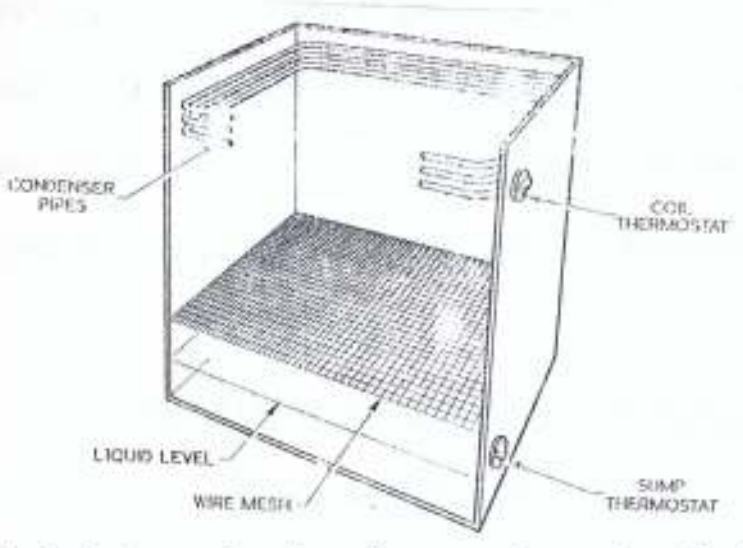


Fig 5 Cut-away drawing of vapour degreasing plant.

The vapour from the boiling liquor rises into the centre portion of the vessel and these condenses on the cold work (Mark, 1983). The liquid dissolves any soluble oils or greases present and runs back into the sump for redistillation. Any vapour passing the work is caught by the condensation coils and also returned to the sump.

2.4.2.1 EMULSION CLEANERS. The accumulation of grease in immersion and solvent cleaners leads to a redeposition of removed soil as

the drag-out liquid evaporates from the surface. In order to overcome this, emulsion cleaners or solvent emulsion cleaners were devised. These add strong emulsifying and wetting agents to the solvent, so that after immersion , the surface of the work can be water-washed and the grease and other residues may be removed in the form of an emulsion (Mark, 1983).

Depending on solvents and emulsifiers selected, these cleaners can be used cold, or diluted with water as a hot immersion process, or hot at considerable dilution in spray- washing machines. In every case the emulsion-cleaner stage is followed by one or more water washes.

2.4.2.2 MECHANICAL METHODS OF REMOVING RUST AND SCALE

WEATHERING. This is commonly employed method of removing mill-scale from heavy structural members.

FLAME DESCALING. This method uses a fish tail or bar-type oxy-acetylene burner to heat the scale layer and crack it off by differential expansion (Stoneley, 1999). It is an excellent method of descaling substantial structures and leaves a worm, dry surface on which to paint. The process employs a mixture of equal volumes of acetylene and oxygen, consuming about 15 ft^3 each per 30 in./min.

SHORT AND GRIT BLASTING. The basis of short and grit blasting is the mechanical projection of hardened steel shot or cut wire grit on to the surface to be cleaned. It can be completely mechanized or operated as a manual process. The grit is thrown at the work either by allowing it to drop on to resolving paddles or by feeding it into a stream of compressed air. In either case the shot and scale drop on to riddles which screen off the scale and broken shot, allowing the whole shot to return to a hopper for re-use. From time to time the shot or grit should be picked over and worn pieces removed.

Various pieces of equipment have been design for carrying out the process. Individual items may be grit blasted by introducing them into a cabinet through one wall of which projects a pair of heavy rubber gloves by means of which the operator holds the work-piece, turning it from side to side so as to expose all faces to be blasted, alternatively, the shot is delivered through a flexible pipe which can be held in the gloved hand (Stoneley, 1999) and directed as required (fig. 2.6).

loosened, and then washed away. Pastes may be allowed to dry and then removed by brushing. The action of the acid may be facilitated by wier brushing. Washing is not always used, especially if non-thickened solutions have been employed, and coating is to be applied as soon as the surface has dried.

SODIUM HYDRIDE DESCALING. This is most versatile method of scale removal, although, it is expensive to operate. It will work well on metals ranging from mild steel to high-nickel / chromium alloys. The process employs the intensive reducing activity of bath of molten caustic soda containing 1.5- 2.5 per cent of sodium hydride at a temperature of 350- 370^{0}c. The hydride is generated in the bath by the interaction of hydrogen and sodium; the hydrogen is derived from cracked ammonia, and the sodium is contained in a perforated steel box welded on to the inner side of the tank. The cracked ammonia is passed over the sodium by means of pipes, which enter at the top of the generating box and then dip below the level of the molten caustic soda.

The normal sequence of operation is:

Preheat→ Sodium hydride bath→ Drain→ water quench.

2.4.2.4 APPLICATION METHODS

The coatings can normally be applied in one of four ways.

i. **DIPPING INTO A LIQUID PLASTISOL.** The plastisol method of coating consists of dipping a heated and primed article into a tank of cold liquid p.v.c. The action of the heat causes the plastisol and polymer to cross link forming a gelatinous deposit. A subsequent curing operation complets the reaction, giving a tough resilient coating. The only material that is applied by the plastisol method is p.v.c. and it should be remembered that while this technique is ideally suited to anti-corrosive or protective coatings, it does not give such an attractive appearance as can be achieved with a powder technique. Tanks, pipes, or fabrications can be coated up to ½ in. thick in one operation.

ii. **DIPPING INTO A FINE POWDER.** The powder technique is used principally for polythene, nylon, penton, and some grades of p.v.c. It consists of dipping the heated article after the necessary metal preparation into a gas-agitated bed of fine powder. The article is subsequently heatsintered. Automatic machines have been developed to handle up to 10000 articles per day.

iii. **SPRAYING.** The high labour costs of spraying tend to make this method of application uneconomic when compared to dipping, but most thermoplastic materials can be applied by spraying if size or other features make it desirable. Some fluorocarbons, can be applied only by this method. Other typical examples of sprayed

coatings include the lining of tanks which are too large to dip or require a one- side coating only of nylon, penton or hard polythene.

iv. **FLAME SPRAYING.** The major advantage of flame spraying is that work can be coated on site. A powder of approximately 60 mesh size is agitated and forced through a flame in front of the pistol, which is surround by an inert gas shield. The powder is therefore heated by convection rather than by passage through the flame itself, which would denature it. The powder in the molten state falls on to the metal in the form of globules which are subsequently fused together by gentle passes of the naked flame. Great skill is required if the coating material is not to be embrittled by excessive heat and this is the principal limitation to the wide adoption of this process.

The most suitable method of application to be used in any instance is dependent upon many factors but, in general, it has been found that where both spraying and dipping can be employed, the cost of raw material saved by spraying only part of a component is more than offset by the extra hand work involved. Whereever possible, dipping is preferable as masking techniques.

2.4.3 MATERIAL SELECTION

More resistant alloys such as austenitic stainless steels, aluminum bronze are preferable in special circumstances where ordinary carbon steel would be unsafe and uneconomical (Tretheway and Chamberlain, 1995). The use of corrosion resistant alloys can be considered as an increase in the control of the anode dissolution. This result from the fact that either the anode reaction is rendered completely sluggish or in the formulation on the surface alloy of protective films.

2.4.4 CONTROL OF ENVIRONMENT

If the environment can be altered to make it non -corrosive, then clearly, this will reduce the deterioration of the metals exposed to it to control corrosion in near neutral aqueous environments is to remove oxygen (Chandler, 1985). Another method is to make the solution alkaline by treating them with suitable chemicals such a sodium carbonate.

Inhibitors are organic substances that dissolve in the corroding medium but are capable of forming a protective layer of some kind either the anodic or cathodic areas. Inhibition is used in many situations in aqueous solutions such as supply waters and cooling waters using seawater in condensers and heat exchangers.

Example of inhibitors are anodic type (chromates and phosphate), cathodic type (magnesium and calcium salts) mixed type (polyphosphates), pickling-inhibitors (alcohols, aldehydes, ketones, anines etc) and vapour phase inhibitor.

2.4.5 CATHODIC PROTECTION

This method makes the metal to be protected as the cathodic of the corrosion process. Since corrosion involve a flow or loss of electrons (Fontana, 1986), they are supplied to the steel to be protected from either of two sources:

a. Sacrificial galvanic anodes

b. Impressed current through insoluble electrodes

Then the anodic reactions will be suppressed, the potential will be lowered no current will flow between the anode and the cathode and hence corrosion will cease.

Cathodic protection offers the most effective for corrosion control. It is used universally in the offshore industry.

a. SACRIFICIAL ANODE CATHODIC PROTECTION

This is by introducing a more active metal (Sacrificial anode) such that the structure itself is made the cathode of a galvanic couple (Chamberlain and Tretheway, 1995). These anodes are bars, of metal made of aluminum, magnesium, zinc or alloys of these metals, and have a

negative potential below that of the metal to be protected. The anodes are bolted or welded to the metal structure to be protected.

A continuous and adequate current of electrons flow from the sacrificial metal through the welded or bolted joint into the metal to be protected, thereby assuring that it will be the cathode of the corrosion cell. A good sacrificial anode will develop insignificant anodic polarization during its service life; it will also have a low rate of dissolution. In a typical offshore structure there may be several anodes on a single brace due to the large size (Pickering et at, 1989). As part of the manufacturing process sacrificial anodes for offshore structure are generally cast about the steel pipe, and the latter are then welded directly to structural members.

b. IMPRESSED CURRENT CATHODIC PROTECTION

The driving voltage for cathodic protection in this type of system is provided by an external power supply. The current from a dc. source is delivered through auxiliary anode. The areas of steel that were originally anodic reach the same potential as the original cathodic areas (Scully, 1990), so the whole surface becomes a cathode of the new cell, thus stifling corrosion.

A range of materials used for auxiliary anode in marine environment includes scraps steel and cast iron, graphite, high-silicon iron, lead alloys, platinised type anode etc because of the large amount of

current which can be provided by a single impressed current anode, relatively few anodes are required in comparison to the sacrificial case, making it more advantageous.

2.5 PROTECTION FOR OFFSHORE CORROSION ZONES

There are three corrosion zones in offshore:

a. The immersed zone

b. The splash zone

c. The atmospheric zone

2.5.1 THE IMMERSED ZONE

Galvanic corrosion predominates in this zone. The immersed zone is protected cathodically. Either a system of sacrificial galvanic anodes or an impressed current system is used. Protection is directly influenced by the location of the electronic current source (Crawford, 1994), the total area to be protected, water salinity, water temperature, water velocity, tide and current, and shape of the surface.

2.5.2 SPLASH ZONE

Dissolved air in seawater causes metal surface areas near the sea surface to corrode more severely than surface areas at greater depth avoid horizontal bracing in the splash zone and also minimize the steel in this area since it is the most active corrosion zone. It is the most critical area

of protection because of alternate submerged and aeration (Stoneley, 1999).

Non-corrosive coverings are used sometimes in conjunction with increased thickness of steel members. The increased thickness of steel to offset deterioration over a long period of time is called a corrosion allowance.

The steel surface is sandblasted and painted with about 9ml of epoxy, phenolic, neoprene or vinyl coating. This keeps the seawater away from the metal surface stainless steel and monel are mostly used as leg wraps for splash zone corrosion protection.

2.5.3 ATMOSPHERIC ZONE

This zone has the least corrosion rate and is the most expensive to maintain on the basis of total expenditure over a period of time. Only coatings can be used for this portion of the structure. Heavy bodied coatings of epoxy mastic over zinc paint are used. In organic zinc silicate coating is widely used. Frequently inspection of coatings is required since full corrosion protection is achieved only when the coating is uninterrupted or continuous overall period.

2.6 PETROLEUM

Petroleum is a liquid combustible mineral occurring in the earth's sedimentary mantle (Omorogbe, 1992). It consists of a complicated

mixture of hydrocarbons (alkanes, cyclo-alkanes and alkanes) and compounds containing heteroatoms such as oxygen, sulphur and nitrogen in addition to carbon and hydrogen. The liquid petroleum is commonly called crude oil.

It is an oily liquid fluorescing in the light and its colour depends on the content and structure of the resinous substances in it. Dark (brown or almost black), light and even colourless petroleum are known.

2.6.1 CHEMICAL COMPOSITION

Petroleum is not a uniform material on molecular basis petroleum is a complex mixture of hydrogen and carbons plus organic compounds of sulphur, oxygen and nitrogen as well as compound containing metallic constituents, particularly vanadium, nickel, iron, magnesium, chromium, titanium, potassium, cobalt and calcium. Phosphorus and silicon have also been discovered in it (Craft et al, 1993).

The high proportion of carbon and hydrogen indicates that hydrocarbons are the major constituents of petroleum (15%) with other elements appearing as organic compounds. So therefore, the chemical component are grouped into two groups:

a. Hydrocarbon components

b. Non-hydrocarbon components

TABLE 1: CHEMICAL CONSTITUENTS OF PETROLEUM

1.	Carbon	87.0%
2.	Hydrogen	14.0%
3	Nitrogen	2.0%
4	Oxygen	1.5%
5	Sulphur	6.0%

2.6.2 OFFSHORE ENVIRONMENT – SEAWATER

Offshore simply means away from the shore or land i.e. sea or ocean which is the vast expanse of sea water that covers the greater part of the earth. Seawater is the only electrolyte containing a relatively high concentration of salts that occur commonly in nature covering two-thirds of the earth's surface (McCaslin, 1987). It is the most familiar and one of the most severe of natural corrosive agents i.e. It is characterized by its aggressive nature.

2.6.3 OIL SPILLAGE

Oil spillage has become a common hazard in the environment especially on locations of oil production installations both onshore and offshore.

The greatest pollution risk arises from mechanical damages to pipelines in waterways. The offshore locations where these pipes are put into service are constantly under influence of some unavoidable natural

forces such as waves swells, tidal and sea current, squalls and bad weather conditions, mechanical damages, pressure surges and most importantly, corrosion. Although, corrosion itself plays a minor part in total current leakage history, but cannot be emphasized. This is greatly attributable to the advance in both the science and application of coatings and cathodic protection.

2.6.4 OCCURRENCE / CAUSES OF OIL SPILLS

1. Corrosion of ageing pipelines (flow lines)
2. Failure or rupture in oil pipelines and hoses
3. Drilling accidents such as oil well blow out
4. Equipment failures and human operational errors at flow stations
5. Overflow of drilling mud
6. Depot leakage
7. Third party sabotage and shipping and terrestrial traffic accidents.

A high percentage of these spills occur in sensitive environments both on

offshore and onshore are in Nigeria especially in purely mangrove swamp zones and offshore areas of the Niger-Delta which consist the most productive biological areas.

2.7 PIPELINES MAINTENANCE

Pipeline maintenance demands an early and accurate detection of external corrosion of buried steel pipe.

The conventional method of excavation poses many problems (excavation cost, inspection limited to the range of excavation traffic congestion resulting from the excavation work, a system was thus developed whereby loss of wall thickness due to external corrosion can be detected from inside the buried pipeline.

2.7.1 PIPELINE INSPECTION

Protective coating of pipelines is being inspected on defects by the potential gradient survey method that conducts signal current to the coating defect area and located them from the change of potential gradient. Fig 3.5 & 3.6. The system used for this inspection is called super codins coating defect inspection system. (Suzuki etal 1994).

Super codins consist of a TRANSMITTER for applying signal voltage between the buried pipeline and ground electrode and conducting leakage signal current to the coating defect points of the pipeline, and a RECEIVER that measures the potential gradient produced by the leakage current.

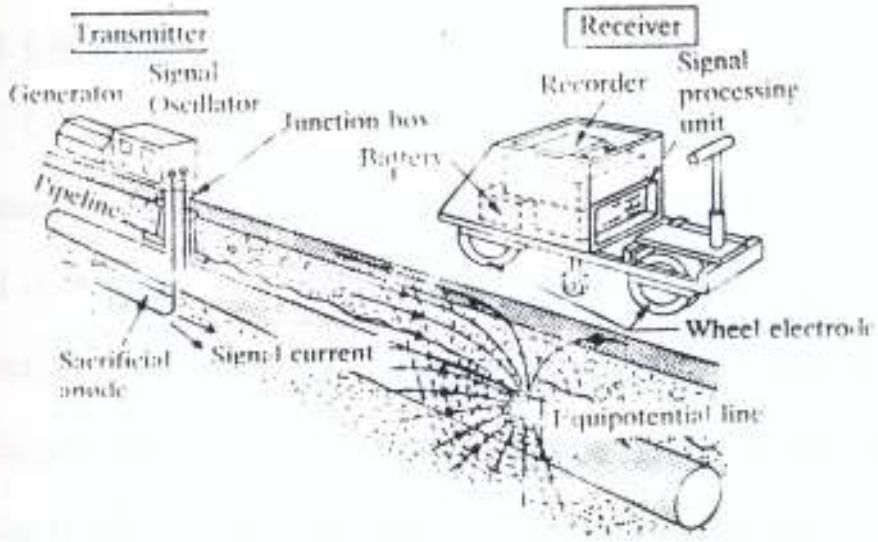


Fig 7: Super Codins System

The procedure involves wheeling of the super codins machine over the surface of the buried pipeline. The potential gradient remains uncharged (constant) as long as there is no presence of coating defect points. The receiver records a change of the potential gradient a soon as there is presence of defect area as the system continues to be wheeled on its wheel electrodes.

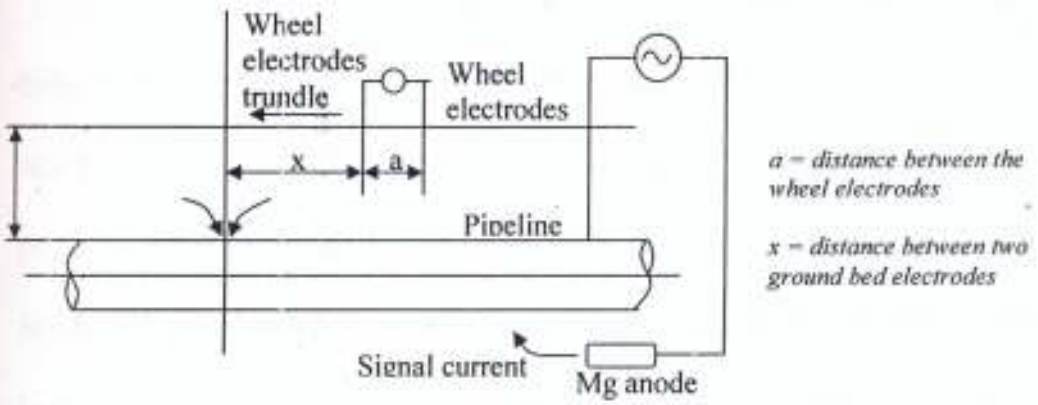


Fig 8 - Inspection Method with Wheel electrodes

2.7.2 CRITERIA FOR PROTECTION

Loss of ions from the anode ceases when the corroding system is polarized to the open - circuit potential of the anode. Consequently the usual criterion for protection is that the potential of the structure with respect to the sol just outside it should not be less negative than the open - circuit potential value. For pipelines where the labour of excavating or drilling in order to place the half-cell in the soil immediately above the pipe would be considerable, it is usual to place the half-cell in the surface vertically above the pipe (Farrer, 1957).

CURRENT REQUIREMENT

The amount of current required to protect a surface depend on a large number of factors, the most obvious of which are listed and discussed below.

COATING

The quality of the coating on a surface determines the amount of bone metal in contact with the electrolyte and also the amount of current, which will actually flow through the coating. The current required to protect a pipeline depends almost completely on the coating and all other factor are of secondary importance e.g. a well coated line of about 250km length has been brought to protection potential by 2A, whereas a similar bare live and require 1000A. (Morgan, J.H).

TYPE OF SOIL

The type of soil is important when coating quality is different, particularly with regard to resistivity and bacterial activity. Generally speaking the lower the sol resistance the larger the current required (Peterson, 1978). When the soil contains very active sulphate reducing bacterial initial current demand may be very high indeed, so that the attainment in the first instance of protective potential is not practicable.

OXYGEN ACCESS

This factor is associated with oxygen concentration in the electrolyte and degree of turbulence. The latter reduces the thickness of the boundary layer through which the oxygen must diffuse. In general this factor is more since the most corrosive types are generally waterlogged soils where oxygen access is in any event limited (McArthur, 1988) In highly turbulent oxygenated liquid current densities on uncoated metal of the order of 150mA/ft^2 may be necessary.

THE NATURE OF THE ELECTROLYTE

In the presence of high concentrations of cathod depolarizers, acid solutions, very large currents may be required to produce protection. The most important instance of acid solutions is a situation in which hydrogen ions can be discharged.

POTENTIAL DISTRIBUTION

The path of an element of current is from the surface of the anode to the surface of the structure under protection. The type of potential gradient involved is shown in Fig 2.7

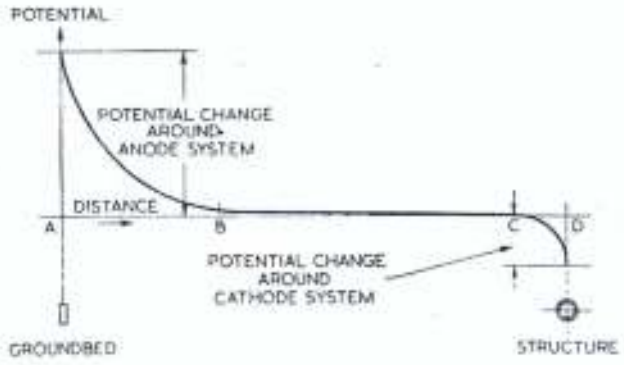


Fig 9: Potential distribution between ground bed and protective structure

The ground bed is made positive and the structure is made negative with respect to the bulk of the ground. The same current flows from the anode as flows to the cathode and since the cathode (the structure) normally has a vastly greater area than the anode (except for extremely well insulated structures) the potential gradients are much steeper around the anode. The total path of current flow may be divided into three sections: AB, which includes the large potential change around the

ground bed, BC, where the current is flowing through an extremely large cross section of soil so that the potential change is very small; and CD, the region where the cross section of flow decreases and the potential drop increases appreciably as the current element approaches the structure.

The potential between of A and B is normally in the range (depending on ground bed size and soil resistivity) 10-50v, and the potential CD, 1-2v (Preiser & Tytell, 1958).

The number of current sources required to protect a surface, and their distribution, are determined by the requirement that the minimum potential for protection must be attained at all points of the surface at the minimum cost. The potential distribution depends on:

i. General geometry of protected surface, electrolyte and anodes

ii. Resistivity of electrolyte

iii. Resistance of coating(s) at metal / electrolyte interface

iv. Resistance through structure by metallic path

2.8 ELECTRICAL INTERFERENCE

The current flowing through an electrolyte from an anode to a structure under protection produces a potential field in the electrolyte. If other structures (which are not part of the protection scheme) exist in the vicinity of either the ground bed or the protected structure field may

cause current to enter and leave the secondary structures (Nelson, 1988), at the point of current entry a measure of protection exists, and at points where current leaves increased corrosion will occur.

2.9 BONDING AND INSULATION OF PROTECTED STRUCTURES

The whole of the structure to be protected must be in low-resistance metallic contact, and in order to confine current flow to the sections which are to be protected the terminals of the protected structure must be electrically insulated from other structures to which it may be mechanically connected.

2.9.1 BONDING

Low resistance metallic bonding is essential and where this is not provided in the design is must be added. For example, if a pipeline is to be protected all section of pipe must be properly bonded by cables or metallic straps, and if jetty piles are not electrically continuous, reinforcing must be welded to give a low- resistance continuity. Conductance achieved by the presence of a highly conducting electrolyte between flanges of a pipe is not satisfactory as current will leave the metal near the flange and rapid internal corrosion of the pipe will be caused (Ewing & Hutchism).

2.9.2 INSULATION

Limitation of current to the section to be protected is desirable both to save electric power and also to prevent possible electrical interference at remote points. When a section of a line is insulated, the current flowing to the protected section may cause adverse potential shifts. Thee adverse effect can be eliminated by shunting the insulated flange with a resistance. Current flowing through the resistance is collected by the unprotected section of line, which experience a cathodic shift due to the current. The resistance is adjusted o that just enough current flows to eliminate the adverse effect on the unprotected side of the flange. (Fig.10)

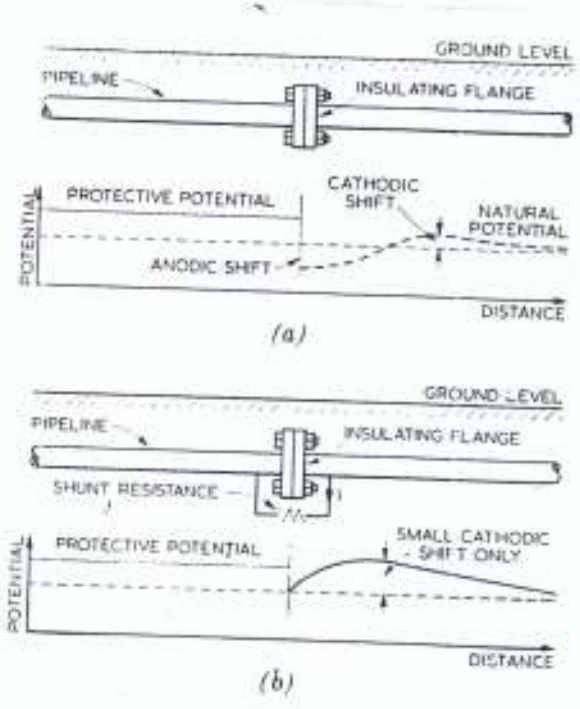


Fig 10: ***(a). Anodic potential shift on unbonded structure***
(b). Elimination of anodic shift by resisting bonding of unprotected structure

2.10.1 SOIL-RESISTIVITY SURVEY

Soil resistivity surveys carried out by the Wenner technique with an instrument such as a four-pin Megger can establish soil resistivities. (Fig 11) and indicate the probable corrosiveness of the soil. Variation in the soil resistivities may, however, simulate localized corrosion, and can cause long-line currents. It is therefore not possible to give any precise ruling as to the rate at which corrosion will occur under any particular soil condition (Fig 11) and the result of any survey must be taken as giving only a general indication of probability of corrosion. Chemical and other forms of industrial contamination of the soil can, however, significantly influence soil resistivities and corrosion characteristics, (Peterson), and it is inadvisable to place too much fourth in any results where such contamination may have occurred (e.g in the proximity of gas works and chemical plants).

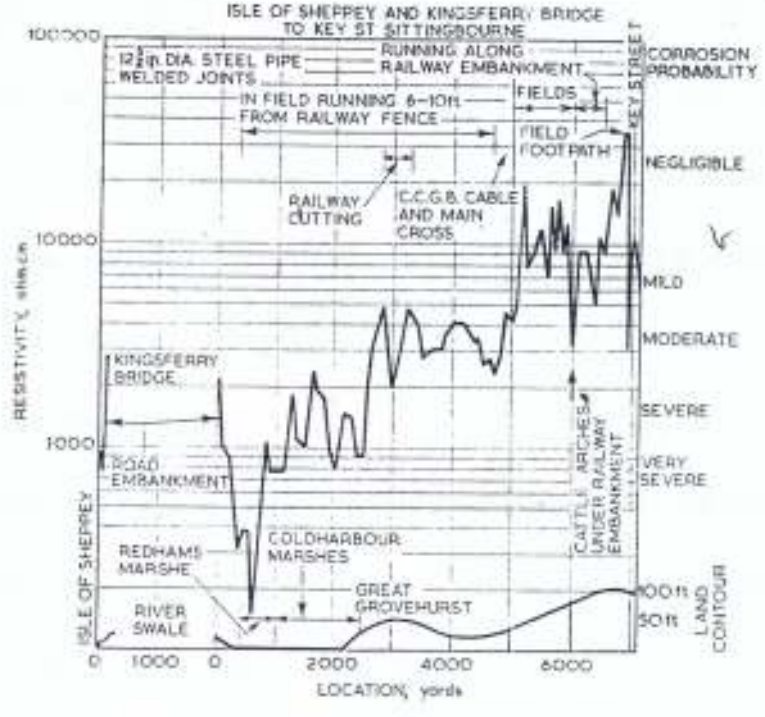


Fig 11. Typical soil resistivity survey

Soil - resisting surveys will nevertheless normally indicate whether cathodic protection is advisable, and whether impressed current or sacrificial schemes are preferable. It may as the result of survey, be considered desirable to apply total protection or to limit protection to certain area or 'hot spots'. The cost of protecting uncoating structures will, however, be high and the expense may prohibit complete protection.

2.10.2 GROUND BED INSTALLATION

When the anticipated current requirement have been established or deduced, the ground bed location must be settle (Parker, 1972). The ground beds should be of reasonable capacity depending on soil resistivities, and will have to be chosen after consideration of large-scale maps. Once the ground bed locations have be selected, the soil resistivities must be checked and it is advisable to run series of tests with a range of probe spacing to establish the resistivities of the substrata to ensure the probability of adequate current dissipation to more remote parts away from the ground bed

The method of intalling the ground bed (i.e vertical or horizontal anodes) should then be decided on. The following abridged formula is normally used for design (Peterson, 1978).

Resistance of a long horizontal rod

$$R_H = \frac{p}{2\pi L}\left(In\frac{4L}{d} - 1\right)$$ ----------(11)

Resistance of a vertical rod

$$Rv = = \frac{p}{2\pi L}\left(In\frac{8L}{d} - 1\right)$$ ----------(12)

Where:

R_H = Resistance of horizontal groundrod, in ohm.cm

Rv = Resistance of vertical groundrod in ohm.cm

P = Soil resistivity in ohm.cm

L = Length of rod or pipe (cm)

d = diameter of rod (cm)

The optimum size and number of anodes can then be determined and the anode spacing settled. This is normally about three times the length of the anode.

It is usually preferable from the point of new of cost and labour factors to install ground beds horizontal, but if drilling machines are available and soil conditions are suitable, vertical installation may be preferred.

CHAPTER THREE

3.0 MATERIALS AND METHODS

Questionnaires were administered and the information provided therein were used to investigate the corrosion characteristics of pipelines in different oil and gas installation of NNPC, Shell Petroleum Company and Chevron Petroleum Company. Parameters affecting pipeline degradation and coating defect area were measured and these include: diameter of the pipeline, applied current, coating thickness, leakage resistance, potential gradient, soil resistivity and depth of burial of pipeline.

3.1 PRELIMINARY INVESTIGATIONS

These form the basis of the research work. The acquisition of necessary and vital information helps in the investigation techniques.

On a number of visitation to NNPC, Ibadan, SHELL Petroleum Development Company, Warri and CHEVRON petroleum company, vital information useful for this research work were obtained. These include: various modes of failure investigation; major components involved in failure investigation; Types of corrosion related failure on offshore oil production. These are presented in Tables 2 to 4

TABLE 2: MODE AND PERCENTAGES OF FAILURES EXPERIECED IN VARIOUS SELECTED OIL COMPANIES

	Types of Failure	Percentage		
		NNPC	SHELL	CHEVRON
1.	Corrosion (all types)	31	32	30
2.	Fatigue	14	18	15
3.	Mechanical damage / overload	16	13	17
4.	Brittle fracture	7	9	6
5.	Frabricaton defect	8	10	7
6.	Welding defect	6	7	6
7.	Analysis and quality testing	10	9	9
8.	Others (vandalization)	8	11	10

TABLE 3: MAJOR COMPONENTS INVOLVED IN CORROSION INVESTIGATION AND THEIR PERCENTAGES

	Items	Percentage		
		NNPC	SHELL	CHEVRON
1.	Production pipe work and vessel	21	23	22
2.	Pumps and Compressors	17	18	16
3.	Down hole production equipment	14	15	15
4.	Drilling and wire line equipment	14	14	13
5.	Conductors and casings	13	11	14
6.	Cranes and lifting equipment	12	9	13
7.	Water injection equipment	9	10	7

TABLE 4: **TYPES OF CORROSION RELATED FAILURE ON OFFSHORE OIL PIPELINES INSTALLATION.**

Type of Corrosion related failure		Value		
		NNPC	SHELL	CHEVRON
1.	CO_2	10	9	9
2.	H_2S related	4	5	4
3.	Preferential weld corrosion	5	5	4
4.	Pitting	4	3	4
5.	Erosion	2	3	3
6.	Galvanic	1	2	1
7.	Crevice	2	1	1
8.	Impingement	1	2	2
9.	Stress corrosion	2	1	2
10.	Others	1	1	1

Further interaction with site engineers gives room for further investigation necessary to achieving the aim and objective of the research work. These include coating of the steel pipe and inspection of buried pipelines.

Protection for periods varying from hours to years may be obtained by the formation of a surface layer, which is impervious to water, oxygen and likely atmospheric contaminants by coatings (Scully, 1990). Such coatings are either formed by the application of greases or fats (which may usually be subsequently removed by the use of petroleum solvents), or by the use of organic polymers or rubber lax which can be stripped off (Williams, 1990).

Thin soft films of product are deposited in the cold (room temperature). Application is best by dipping or spraying because brushing may result in less complete coverage. All surface must be accessible for cleaning and coating (Scully, 1990).

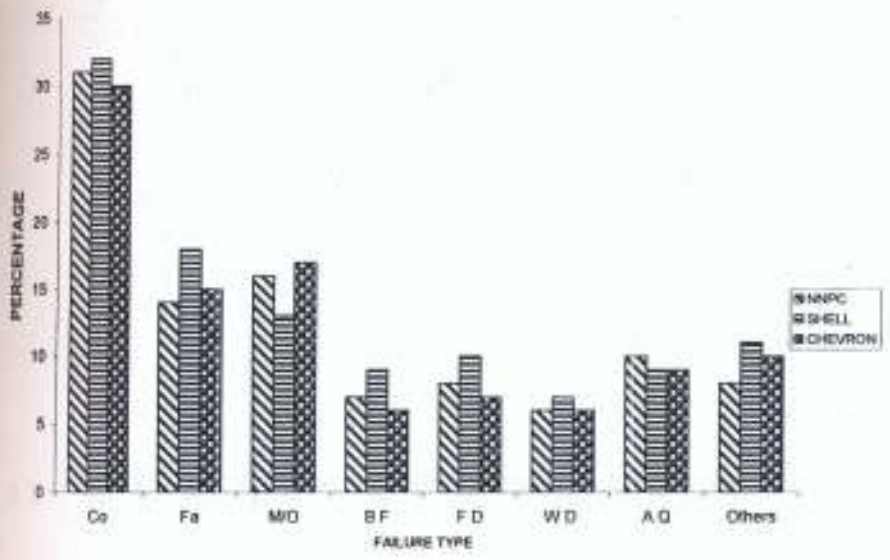


Fig 12: Mode and Percentages of failure experienced in various selected oil companies

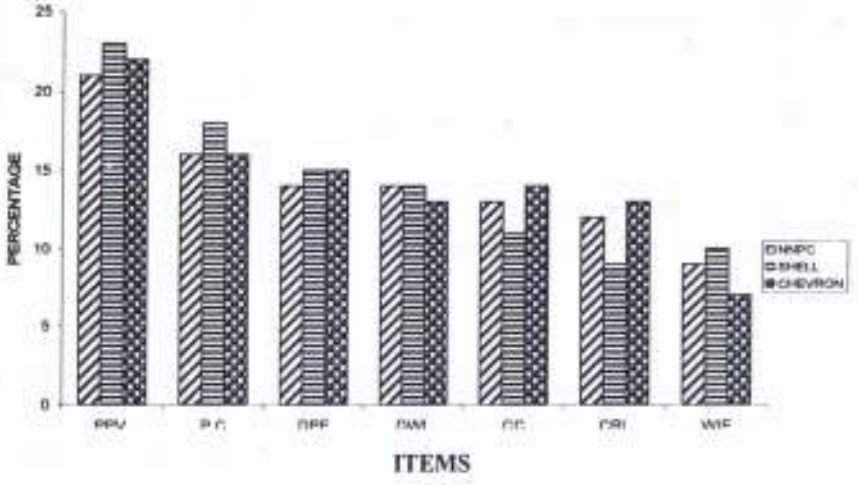


Fig 13: Major components involved in corrosion investigation and their percentages

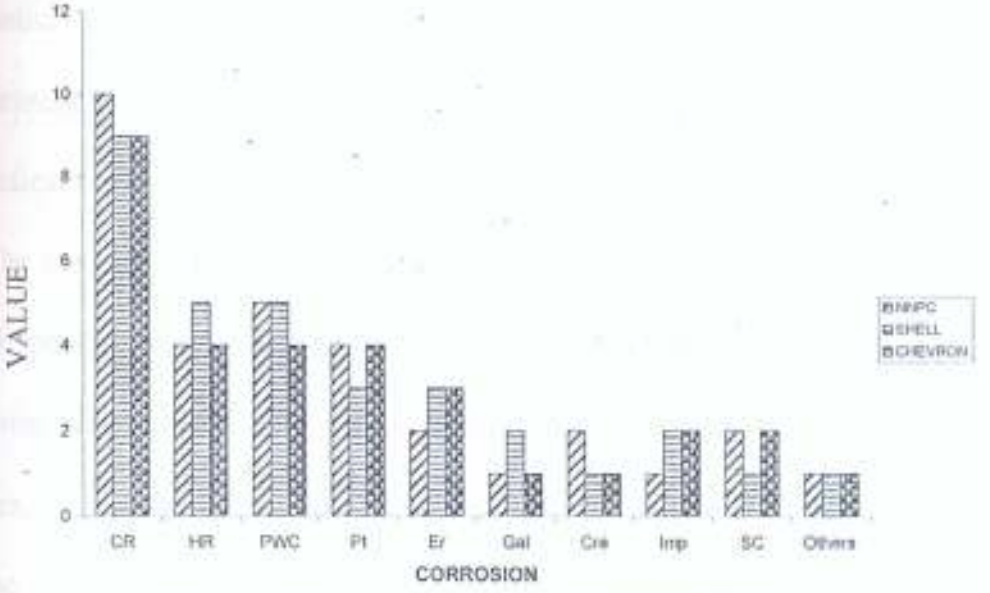
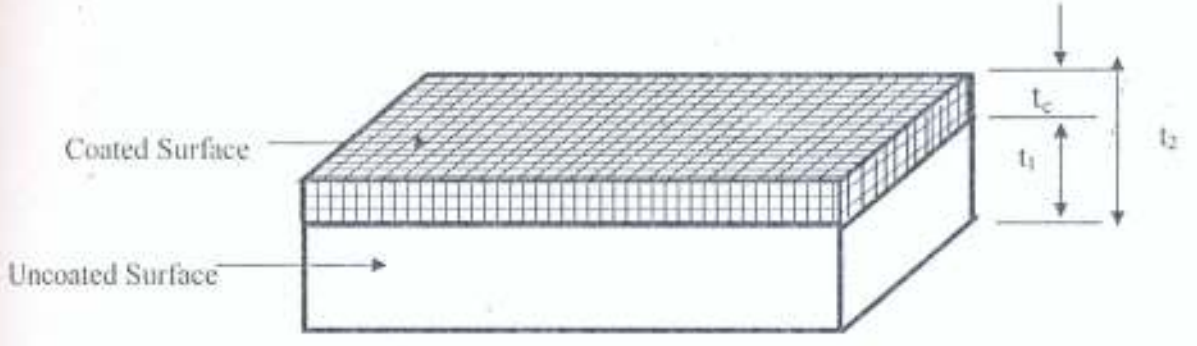


Fig 14: Types of Corrosion Related Failure in offshore oil pipeline installation

3.2 CALCULATION OF COATING THICKNESS



Where t_c = coating thickness

t_1 = thickness of steel pipeline before coating

t_2 = thickness of steel pipeline after coating

$$t_c = t_2 - t_1$$

Fig 15: SAMPLE OF COATED STEEL PIPE

3.3 MODEL DEVELOPMENT

Model can be described to be a simplified representation of a certain aspect of a real system. Mathematical model is a representation of

the essential part of an existing system (or a system to be constructed), which present knowledge of that in a usable form and is created using mathematical concepts such as functions and equations.

The main aim of formulating models in this work is to provide a basis to predict the defect surface area in oil and gas pipeline installations. The model was developed from the earlier work by Suzuki and others.

The simulation conditions are presented in Table 5 and the simulation model is presented in Fig 19.

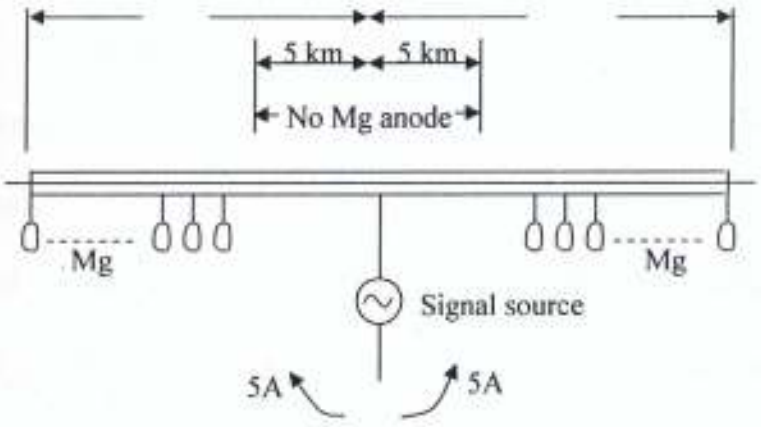


Fig 16 - Simulation Model

TABLE 5: PARAMETERS USED IN DEVELOPING THE COMPUTER PROGRAMS

Parameters that affect coating defects area		Condition		
		NNPC	SHELL	CHEVRON
1.	Size of Pipeline	700.0mmϕ 12.50mmWT	700.0mmϕ 12.5mmWT	695.5mmϕ 12.5mmWT
2.	Length of Pipeline	500.0km	400.0km	500.0km
3.	Resistivity of Steel Pipe	$6.22x10^{-6}\Omega m$	$6.20x10^{-6}\Omega m$	$6.50x10^{-6}\Omega m$
4.	Coating Resistance	1.40 $k\Omega m^2$	1.50 $k\Omega m^2$	1.50 $k\Omega m^2$
5.	Coating Thickness	5.0 μ m	5.0 μ m	5.0 μ m
6.	Anode Installation	6 within 5km	2 within 4km	4 within 10km
7.	Signal Current	6.0A	5.0A	5.5A

3.4 THEORETICAL CONSIDERATIONS

Principle and Application of coating defect inspection: The protective coating of pipelines may be inspected of defect by the potential gradient survey method that conduct signal current to the coating defect and locates them from the change of potential gradient (Suzuki et al 1990) This is characterized by a great ease of measurement and little interference from other structures.

Principle of potential gradient survey: A current source A when located at depth Zo, the potential of a given point P(x,y,z) in the ground can be obtained by the method of electrical images that imagines a similar current source A, as shown in Fig (17). If Q(Ω.m) is mean soil resistivity

and I (A) is current, the potential V is given by

$$V = \frac{\ell i}{4\pi}\left[\frac{1}{\sqrt{x^2+y^2+(Z-Zo)^2}} + \frac{1}{\sqrt{x^2+y^2+(Z+Zo)^2}}\right] \text{ (v)} \text{----------(13)}$$

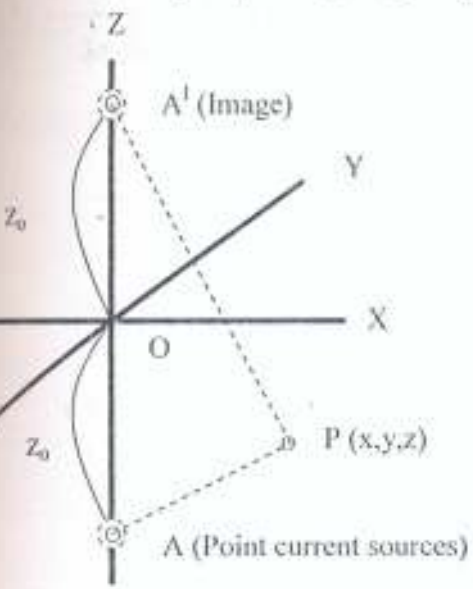


Fig 17: Representation of Coating Defect by method of electrical images

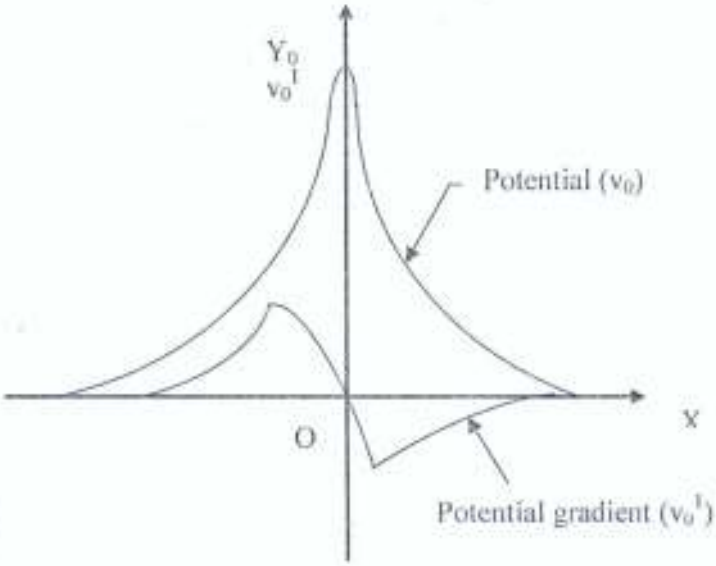


Fig 18: Potential and Current Distribution in Ground

In Fig (18), the dotted lines are equipotential lines of the potential V in the above equation and the solid lines crossing them in sight angles indicate the distribution of the current (i) in the above equation.

If y=0 and Z=0 are assumed in the above equation, the potential at ground surface Vo above the pipeline can be represent by the following simple form.

$$Vo = \frac{\ell i}{2\pi\sqrt{x^2+Zo^2}} \text{ (v)} \text{----------(14)}$$

The potential at ground surface Vo describes a parabola that becomes maximum right above the current source as indicated by the solid line in

Fig (17). Differentiation of equation (14) yields the potential gradient at ground surface Vo^1 as given by

$$Vo = -\frac{\ell I.x}{2\pi\sqrt{\left(x^2 + Za^2\right)^3}} \text{ (v/m)} \text{----------(15)}$$

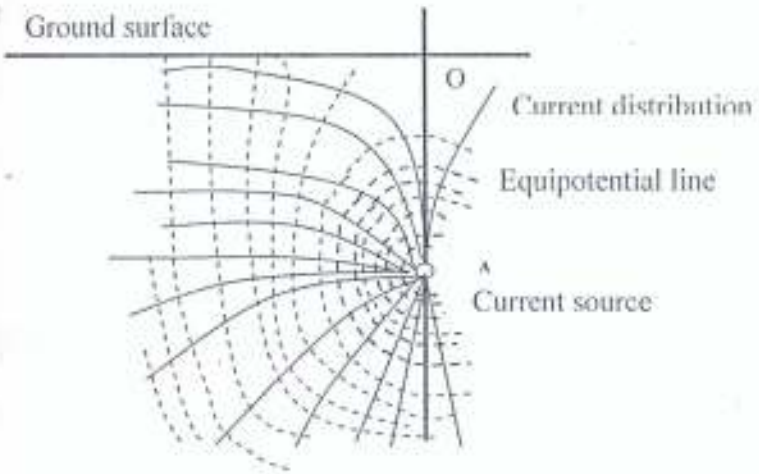


Fig 19: Potential and Potential Gradient at grounds surface

The leakage resistance Cr is given by

$$Cr = \ell\left(\frac{tc}{s} + \frac{1}{\sqrt{2\pi s}}\right)(\Omega) \text{----------(16)}$$

where ℓ = soil resistivity (Ω.m); tc = coating thickness (m); and s = coating defect area (m^2)

The maximum value E of potential gradient between two points 1m apart on the pavement is related to the current i as follows

$$E = \frac{\ell}{k} i \text{ (v)} \text{----------(17)}$$

where k is a factor that depends on the burial depth of the pipeline and is referred to a the (P $\frac{i}{\lambda}$) ratio. The potential gradient E and coating defect area S are related as follows:

$$E = \frac{VpS}{k\left(tc + 0.4\sqrt{s}\right)} \text{ (v)----------(18)}$$

3.5 SIMULATION MODEL

Mathematical model was developed from equation (16) and (18) to develop a computer program for the prediction of coating defect area of buried pipelines

From equation (16)

$$Cr = \lambda\left(\frac{tc}{s} + \frac{1}{\sqrt{2\pi s}}\right)$$

$$\frac{Cr}{\lambda} = \frac{tc}{s} + \frac{1}{\sqrt{2\pi s}}$$

$$\left(\frac{Cr}{\lambda}\right)^2 = \left(\frac{tc}{s}\right)^2 + \frac{1}{2\pi s}$$

Taking log of both sides:

$$\log\left(\frac{Cr}{\lambda}\right)^2 = \log\left(\frac{tc}{s}\right)^2 .\log\frac{1}{2\pi s}$$

$$\log\left(\frac{Cr}{\lambda}\right)^2 = \log\left(\frac{tc}{2\pi s^3}\right)$$

$$2\log Cr - 2\log\lambda = 2\log^2 tc - \log^2 2\pi s^3$$

$$2\log^2 tc + 2\log\lambda - 2\log Cr = \log^2 2\pi s^3$$

$$(2\log^2 tc + 2\log\lambda - 2\log Cr)^{\frac{1}{2}} = \log 2\pi s^3$$

$$\frac{(2\log^2 tc + 2\log\lambda - 2\log Cr)^{\frac{1}{2}}}{2\pi} = \log S^3$$

$$\frac{(2\log^2 tc - 2\log\lambda - 2\log Cr)^{\frac{1}{2}\frac{1}{3}}}{(2\pi)^{\frac{1}{3}}} = \log S$$

$$\frac{(2\log^2 tc - 2\log\lambda - 2\log Cr)^{\frac{1}{6}}}{(2\pi)^{\frac{1}{3}}} = \log S \quad \text{----------(19)}$$

$$\frac{(2\log\ tc + 2\log\lambda - 2\log Cr)^{\frac{1}{6}}}{2\pi^{\frac{1}{3}}} = x$$

let $\therefore \log S = x$

$$S = \frac{1}{\log} x = \log^{-1} x \quad \text{----------(20)}$$

3.6 SYSTEM CONFIGURATION FOR PREDICTING THE COATING DEFECT AREA.

A computer program, Coating Defect Area and potential gradient named CODEAP was developed from equation 16 and 18. This computer program, CODEAP is presented in appendix I.

The prediction of the coating defect area by the program was enhanced. The program was able to evaluate the coating defect area of the steel pipeline at varying simulation conditions such as burial depth of the oil pipelines, leakage resistance etc. The model was able to establish for the three-selected companies: NNPC, SHELL petroleum company, and CHEVRON petroleum company, relationship between

Coating Thickness (tc) and Coating Defect Area (s); Coating Thickness (tc) and potential gradient (t); Coating defect area (S) and potential gradient (t); Leakage resistance (Cr) and potential gradient (E).

3.7 PERFORMANCE VALIDATION OF DEVELOPED PROGRAM

The performance of the system was experimentally validated by varying the burial depth, leakage resistance and applied voltage.

CHAPTER FOUR

RESULT AND DISCUSSION

4.0 ANALYSIS OF DATAS

Information on the questionnaire were presented on bar-charts for comparism among the selected oil companies: These include failure types, (corrosion, fatigue, mechanical damage, brittle failure and fabrication defect), Fig 12, components or equipments involved in failure investigation Fig 13, and various type of corrosion related failure in offshore oil and gas production pipelines installation, Fig 14.

The results of the computer program are shown in Appendix II, and presented on graphs as shown in Fig 20 to Fig 46

4.2 DISCUSSION

Effect of Coating Thickness (Tc) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 4.3703

The result analysis of appendix II.A, as the coating thickness (Tc) is increasing, the value of the coating defect area (S) is decreasing Fig 20. The first stepwise change in the value of the coating thickness ΔTc produces a resultant change in the value of the coating defect area. (ΔS)

A change of value of the coating thickness (ΔTc) from 0.1μm to 0.3μm produces a resultant change in the defect area given a 2.605254mm^2 for NNPC, 3.3338mm^2 for SHELL petroleum company and 3.82886mm^2 for CHEVRON petroleum company. While the optimal value gotten from the difference between the value of the coating defect area obtained from the first value of the coating thickness and the final value of the coating defect area obtained from the final value of the coating thickness.

$(\Delta S) = S_f - S_I$ ----------(21)

Where:

S_f = defect area obtained at final value of coating thickness

S_I = defect area obtained at initial value of coating thickness

The optimal value of the coating defect area for NNPC under the above condition is given as 3.629525mm^2, that of Shell is given as 3.6295258mm^2 and Chevron petroleum company is given as 4.129584mm^2

In the like manner, the potential gradient (E) is decreasing with increasing value of the coating thickness, Fig 21.

Effect of coating thickness (Tc) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 14.2566

From the result analysis in appendix II.B, it will be cleared that the same trend was followed i.e. as the coating thickness is increasing, the value of the coating defect area is decreasing but something is peculiar to values obtained at K = 4.3703 and when K is increased to 14.2566. The values of the coating defect area obtained were just the same. This implies that depth of burial has no significant effect on the coating defect area (S) but only on the potential gradient values. The values of the potential gradient obtained under this conditions for NNPC, SHELL petroleum company and CHEVRON petroleum company were decreasing jut like the former trend but here, they are of lower values Fig 23. Take for instance, at coating thickness (Tc) equals 0.9μm for NNPC, the defect area is left at 0.5724415mm^2 but potential gradient now changes from 1226.888(v) to 343.5289(v)

Effect of coating thickness (Tc) on coating defect area (S) and potential gradient E for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 38.9501.

Just like the previous ones, the results in appendix II.C, relates the variations of coating defect area (S) and the potential gradient (E) for

NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. The corresponding values of the coating defect area (S) for each value of the coating thickness remain the same i.e. not changing from the other values for all the selected oil companies but yet following the trend that the value keep reducing with increasing value of the coating thickness. The potential gradient was found to have greatly reduced with increasing burial depth. The variation of the potential gradient (E) with increasing value of coating thickness was equally found to be reducing as shown in Fig 25. Effect of Burial depth of pipe on the Relationship between the coating thickness, coating defect area and the potential gradient.

Comparing the results in appendix II.A_1, II.B_1 and II.C_1 it shows that the value of the coating defect area 'S' are the same for NNPC at different values of K (K_1, K_2, K_3 and K_4) which is given as 3.6295258mm^2 as the optimal where K_1 = 4.3703, K_2 = 14.2566, K_3 = 38.9501. This is a clear indication that burial depth has no influence on the value of the coating defect area 'S' but on the contrary, the value of the potential gradient decreases as the depth of burial of pipe increases.

In the same way, in appendix II.A_2, II.B_2 and II.C_2, show that the value of the coating defect area (S) for shell are the same for different values of K_1, K_2, and K_3 which is given as 3.6295258mm^2 but the optimal

value of potential gradient decreases with the increase in the depth of burial of the pipe.

Chevron in the same way from appendix II.A_3, II.B_3 and II.C_3 follow the same pattern, that is, the coating defect area is not affected as the values remain the same. This is shown by the optimal value of the coating defect area given as 4.129584mm^2 but the optimal value for potential gradient decreases with increasing depth of burial of the pipe.

Effect of leakage resistance (Cr) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 4.37039.

Appendix II.D gives the relationship between coating resistance (Cr), coating defect area (S) and potential gradient for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. An increase in the value of the coating resistance (Cr) produces an increase in the value of the coating defect area. Fig 29. A stepwise increase of the coating resistance (Cr) produces a coating defect area of 0.007883mm^2, 0.0078832mm^2 and 0.007883mm^2 for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. The optimal value for coating defect area are: 0.048964mm^2, 0.048965mm^2 and 0.0489639mm^2 for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. These

values are so close yet there were little differences which shows how great the value of coating resistance (Cr) affects the coating defect area.

The value of the potential gradient (E) is found out to be increasing with the increasing value of coating resistance (Cr) Fig 32.

Effect of leakage resistance on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 14.2566

Result analysis of appendix II.E gives the relationship between coating resistance (Cr), coating defect area (S) and potential gradient for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. The increase in the value of the coating resistance (Cr) produces an increase in the value of the coating defect area. Fig 30. Here it is found that the same values were recorded for coating defect area for corresponding values of the coating resistance for each of the company at different values of K. A stepwise increase of the leakage resistance (Cr) produces a coating defect area of $0.007883mm^2$, $0.0078832mm^2$ and $0.007883mm^2$ for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively just like when the value of K is 4.3703.

The potential gradient on the other hand keep increasing with increasing values of the leakage resistance Cr. Fig 33. Though here, the value of the potential recorded for corresponding values of coating

resistance are of lower value i.e. the value of the corresponding potential gradient recorded keeps falling with increasing depth of burial.

Effect of leakage resistance on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 38.9501

Appendix II.F relates the variation of coating defect area (S) and the potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. The corresponding values of the coating defect area (S) for each value of the coating resistance was found to be increasing with increasing value of the leakage resistance (Cr). Fig 31. The same values were found to be recorded for coating resistance for each of the company at different values of K. Still, a stepwise increase of the leakage resistance (Cr) produces a coating defect area of $0.007883mm^2$, $0.0078832mm^2$ and $0.007883mm^2$ for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively just like with the other values of K. The optimal value for the defect area are just still the same as with values recorded with other values of K.

The potential gradient, Fig 34 has greatly reduced with this value of K but found to be yet increasing with increasing value of the coating resistance.

Effect of burial depth (K) on the relationship between the coating resistance (Cr). Coating defect area (S) and the potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company.

The results in appendices II.D_1, II.E_1 and II.F_1 show that the value of the coating defect area (S) are the same for NNPC at different values of K, (K_1, K_2 and K_3) which is given as a stepwise increase of the coating resistance that produces a defect area of 0.007883mm^2 and the optimal value given as 0.048965mm^2. These remain the same for all values of K (burial depth). This implies, despite the increase in the value of the depth of burial of the pipe, there is no recorded change in the rate of change of the defect area (S).

On the other way, the value for optimal potential gradient keep reducing with increasing value of depth of burial of the pipe. This is given below:

For K_1, the recorded optimal value of potential gradient is 188.896(v), K_2, it was given as 52.8909(v), K_3, it was given as 19.3593(v)

This shows that potential gradient decreases as the depth of burial increases

Appendices II.D_2, II.E_2, II.F_2 follow the same trend; that is, the values of the defect area (S) for shell are the same for different values of K_1, K_2 and K_3 and the optimal value still remain as 0.048965mm^2.

On the contrary, the value of the potential gradient keeps reducing with increasing depth of burial. This is given below at various values of K.That is, at K_1, a value of 165.819(v) potential gradient was recorded at K_2, a value of 50.8313(v) potential gradient was recorded also and at K_3, a value of 18.605(v) potential gradient was recorded.

This is an indication that potential gradient (E) keeps falling / decreasing with increasing depth of burial.

Appendices II.D_3, II.E_3, II.F_3 also compare how depth of burial affects the coating defect area and the potential gradient for chevron. This also follows the trend as all other selected oil companies mentioned above. The value of the coating defect area (S) for chevron is the same for different values of K_1, K_2 and K_3, which is given as 0.048964mm^2. On the other way, the value of the potential gradient keeps decreasing with increasing depth of burial. This is also given below:

At, at K_1, a value of 172.538(v) potential gradient was recorded

K_2, a value of 52.8909(v) potential gradient was recorded

K_3, a value of 19.3593(v) potential gradient was recorded.

This also shows that depth of burial has no influence on the coating defect area but the value of the potential gradient decreases with increasing depth of burial of oil pipe.

Effect of applied voltage (Vp) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company petroleum company, and CHEVRON petroleum company petroleum company at K = 4.3703.

Appendices II.G shows the effect of the applied voltage on the coating defect area (S) and potential gradient (E). As the applied voltage increase, the coating defect area remain constant, this is shown in Fig 37, the value of the coating defect area remain constant as 0.658978mm^2, 0.6656191mm^2 and 0.6688845mm^2 for NNPC, SHELL petroleum company and CHEVRON petroleum company.

This could also be illustrated by calculation

First stepwise increase of the applied voltage (Vp) from 5000(v) to 5500(v) produces 0.00mm^2 coating defect area for all the selected companies.On the other hand, the value of the potential gradient (E) value is increasing with increasing value of the applied voltage (Vp). This is shown in Fig 39.

A first stepwise increase of the applied voltage from 5000(v) to 5500(v) produces a change of potential gradient of 150.237(v) for NNPC, 152.305(v) for SHELL petroleum company and 153.052(v) for

CHEVRON petroleum company respectively and the optimal value when the applied voltage changes from 5000(v) to 8000(v) produces potential gradient of 904.658(v) for NNPC, 913.831(v) for SHELL petroleum company and 718.314(v) for CHEVRON petroleum company respectively.

This implies that applied voltage (Vp) only have influence on the potential gradient (E) but not on coating defect area (S).

Effect of applied voltage (Vp) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 14.2566.

Appendix II.H relates the effect of the applied voltage on the coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively at K = 14.2566

Just like the first case when K = 4.3703, changes in the value of the applied voltage produces no change in the coating defect area because, the value of the coating defect area remain constant for all the changes in the value of the applied voltage, the value remain unaltered even remain as 0.6589378mm^2 for NNPC, 0.6656191mm^2 for SHELL petroleum company and 0.6688845 for CHEVRON petroleum company respectively and any change in the value of the applied voltage produce 0.00mm^2 change in the coating defect area.

The potential gradient on the other hand increases as the value of the applied voltage increases. Fig 41. A first stepwise increase in the value of the applied voltage produces 46.2198(v) change of potential gradient for NNPC, 46.6885(v) for SHELL petroleum company and 46.9175(v) for CHEVRON petroleum company, and the optimal value is given a 277.31(v) for NNPC, 280.1308(v) for SHELL petroleum company and 281.5052(v) for CHEVRON petroleum company respectively.

Effect of applied voltage (Vp) on coating defect area (S) and potential gradient (E) for NNPC, SHELL petroleum company and CHEVRON petroleum company at K = 38.9501.

Appendix II.I shows the effect of the applied voltage on coating defect area (S) and potential gradient E for NNPC, SHELL petroleum company and CHEVRON petroleum company respectively. Fig 39 show that changes in the value of the applied voltage produces no change in the value of the coating defect area as they all remain constant still given as $0.6589378mm^2$ for NNPC, $0.6656191mm^2$, for SHELL petroleum company and $0.6688845mm^2$ for CHEVRON petroleum company and any change in the value of the applied voltage produces $0.00mm^2$ change in the coating defect area.

On the other hand, the potential gradient increases as the value of the applied voltage increases Fig. 42.

A first stepwise increase in the value of the applied voltage produces 16.9174(v) change of the potential gradient for NNPC, 17.089(v) for SHELL petroleum company and 17.208(v) for CHEVRON petroleum company and the optimal value is given as 101.5049(v) for NNPC, 102.534(v) for SHELL petroleum company and 103.5214(v) for CHEVRON petroleum company respectively.

Effect of K (burial depth factor) on the relationship between the applied voltage (Vp), coating defect area (S) and potential gradient E.

From the result analysis of appendices II.G_1, II.H_1, II.I_1 (NNPC), it was seen that for any change in the value of the applied voltage, there is no change in the value of the coating defect area (S) for all the different values of K. This shows that K (burial depth factor) has no effect just like the applied voltage on the coating defect area (S), but on the contrary, the value of the potential gradient (E) keep reducing with increasing value of K, i.e. the optimal value of the potential gradient falls from 913.831(v) at K = 4.3703 to 277.31(v) at K = 14.2566 then finally reduces to 101.5049(v) when K increases to 38.9501, meaning that the deeper the burial depth of pipe, the lower the value of the potential gradient 'E' .In the same way, from appendices II.G_2, II.H_2, II.I_2, the optimal value of the coating defect area (S) remain constant all through the values of K for SHELL petroleum company but the value of the

potential gradient keeps decreasing with increasing value of K i.e. 913.831(v) at K = 4.3703, 280.1308 at K = 14.2566 and 102.5341(v) at K = 38.9501. This also shows that the deeper the burial depth of pipe, the lower the value of the potential gradient (E).

Appendices II.G_3, II.H_3,' II.I_3 (CHEVRON petroleum company) follow the same trend as above, that is, the value of the defect area (S) for CHEVRON petroleum company are the same for different values of K which is given as $0.6688845mm^2$ but the optimal value for potential gradient decreases with increasing depth of burial (K) of the pipe which is given by the value of the potential gradient (optimal) as 918.314(v) at K = 4.3703 then 281.5052(v) at K = 14.2566 and 103.5214(v) at K = 38.9501.

The value of the potential gradient decreases with increasing depth of burial (K) of the pipe.

CONCLUSION

Corrosion characteristics of coated pipelines of NNPC, Shell Petroleum Company and Chevron Petroleum Company were evaluated. This formed the basis of this research.

Computer program for the prediction of coating defect area for oil and gas pipelines; coating defect area and potential gradient, trade named CODEAP was developed using a q-basic programming language. The developed program was experimentally validated by varying the burial depth, leakage resistance and applied voltage.

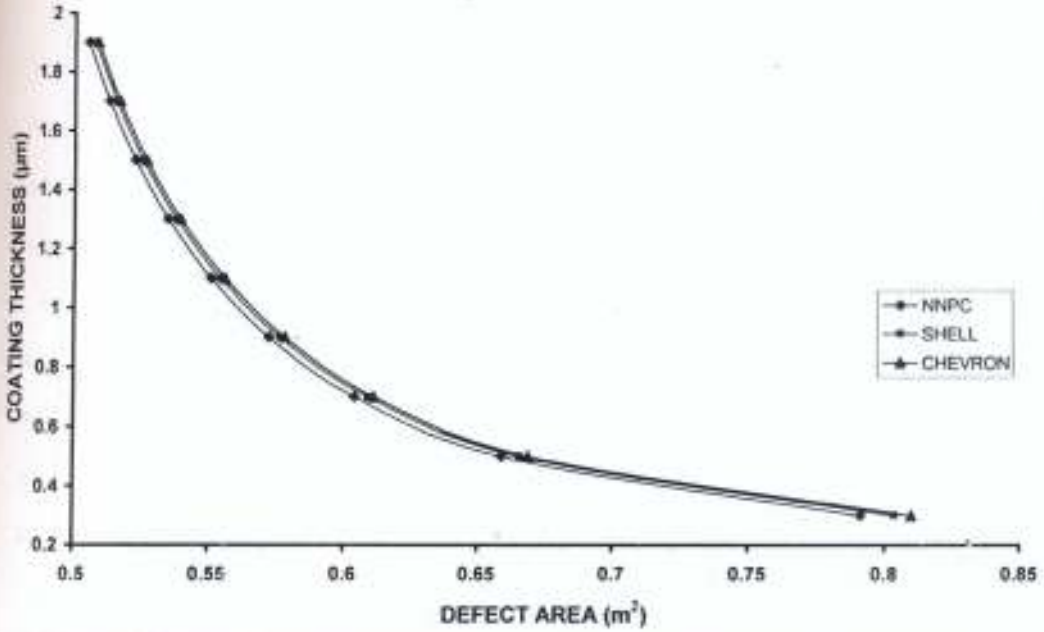


FIGURE 20: PLOT OF COATING THICKNESS AGAINST DEFECT AREA AT K = 4.37039

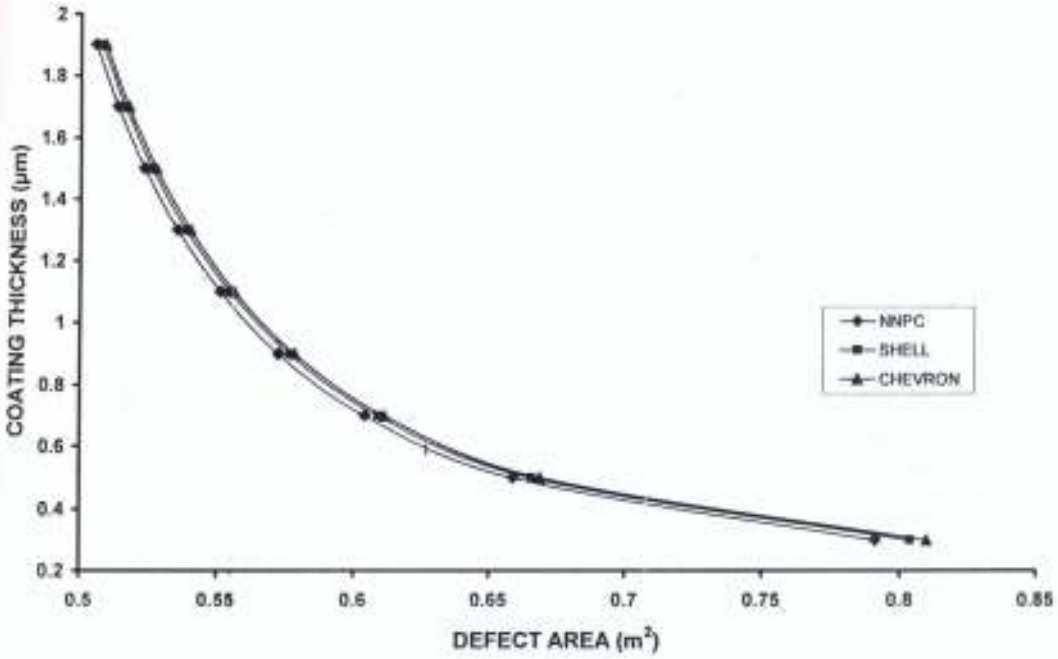
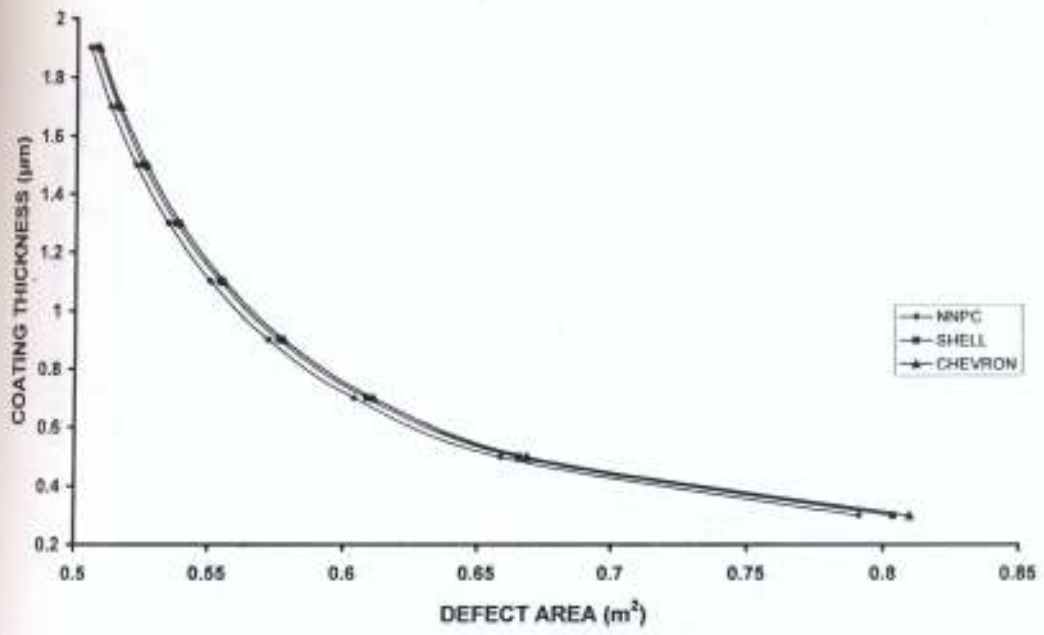
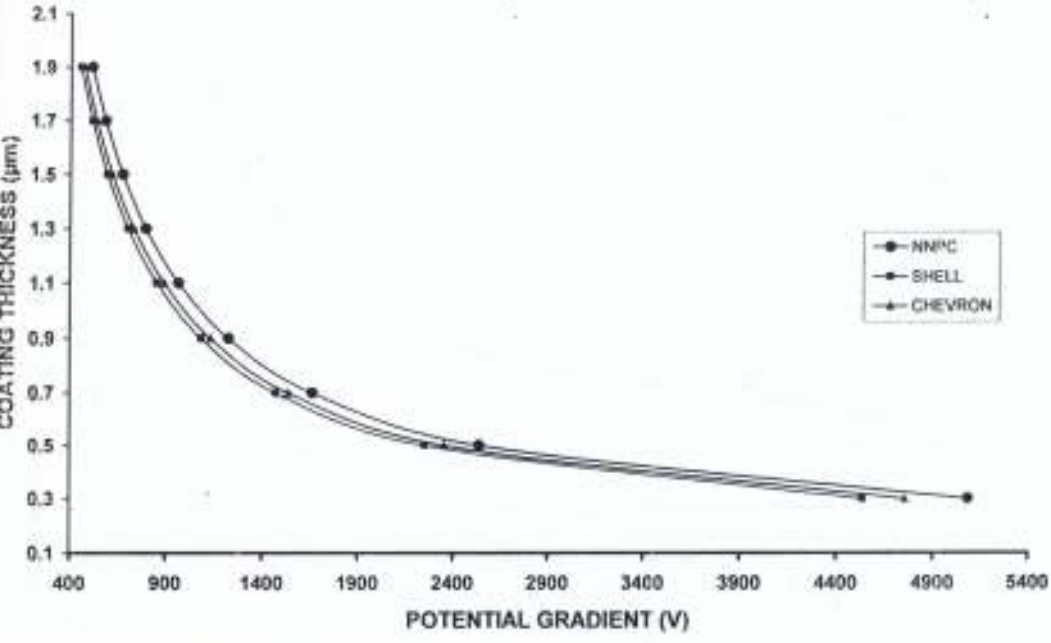


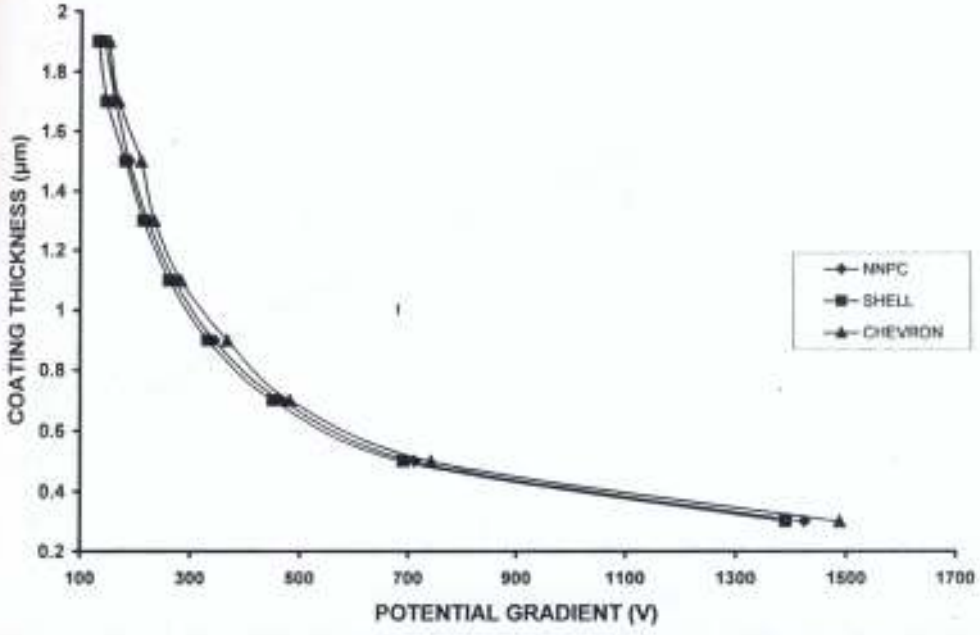
FIGURE 21: PLOT OF COATING THICKNESS AGAINST DEFECT AREA AT K = 14.2566



IGURE 22: PLOT OF COATING THICKNESS AGAINST DEFECT AREA AT K = 8.9501



GURE 23: PLOT COATING THICKNESS AGAINST POTENTIAL GRADIENT AT K = 7039



IGURE 24: PLOT OF COATING THICKNESS AGAINST POTENTIAL GRADIENT AT K= 1.2566

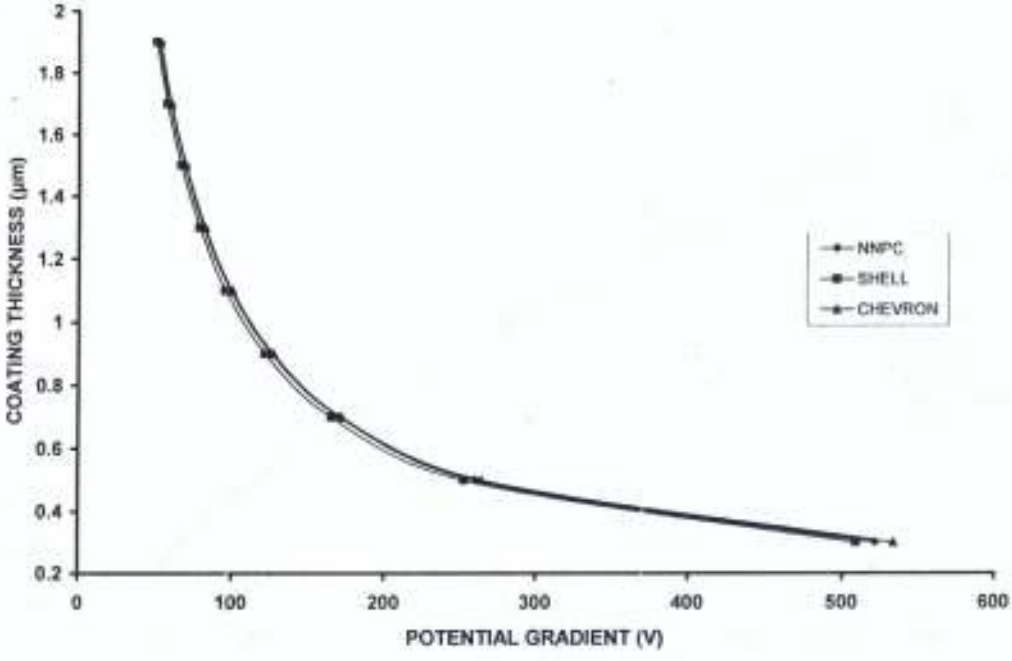
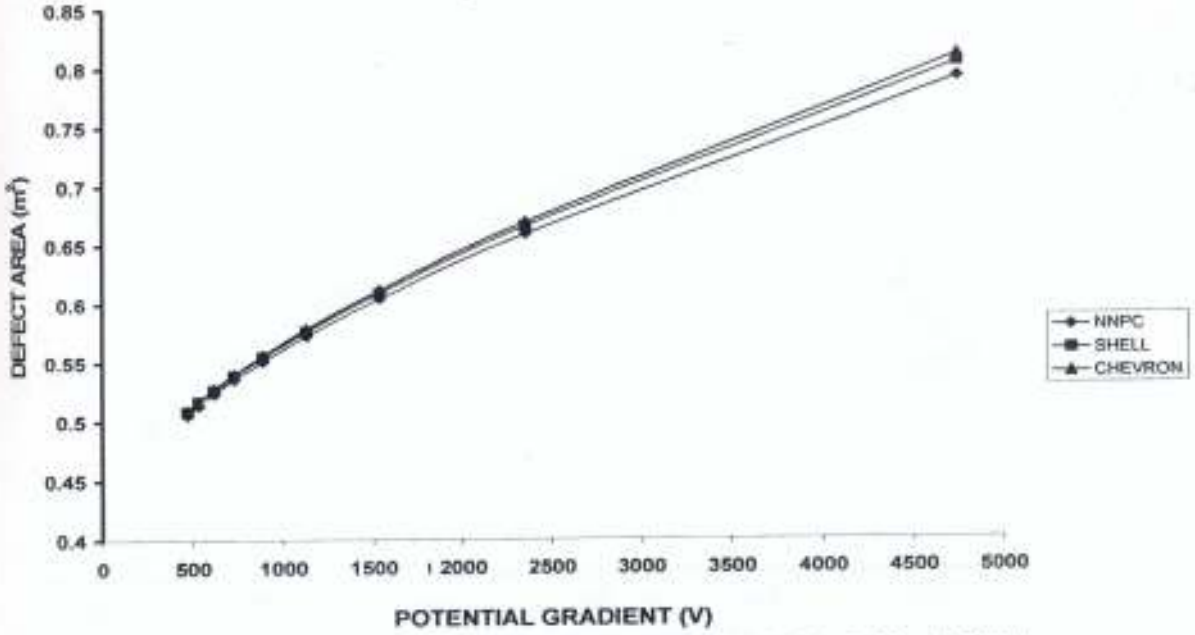
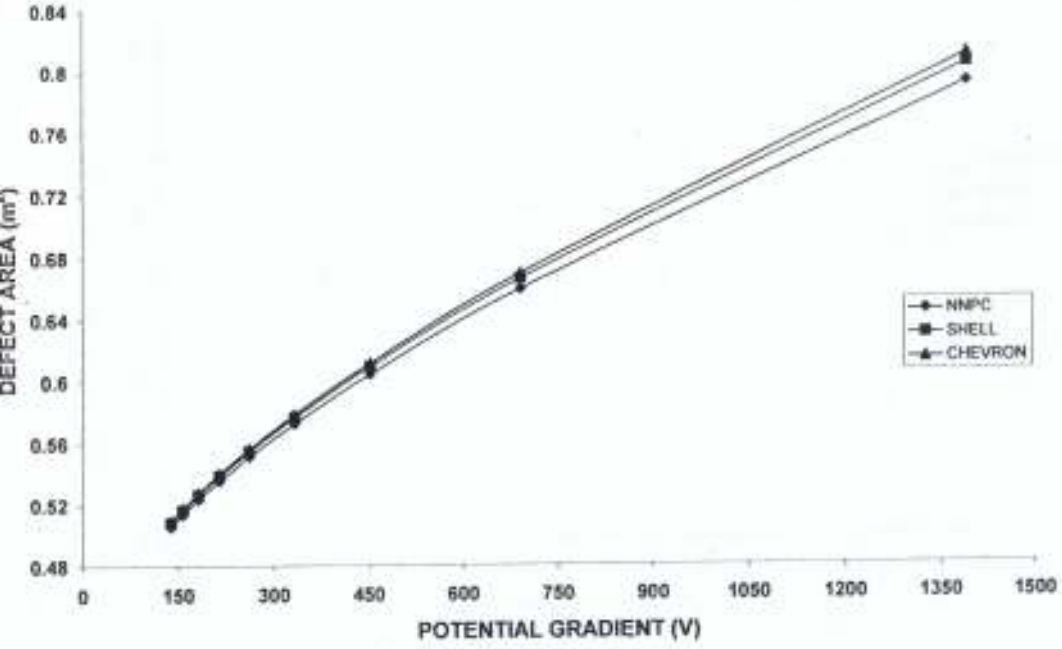


FIGURE 25: PLOT OF COATING TTHICKNESS AGAINST POTENTIAL GRADIENT AT K = 38.9501



IGURE 26: PLOT OF POTENTIAL GRADIENT VS DEFECT AREA AT K = 4.37039



GURE 27: PLOT OF DEFECT AREA AGAINST POTENTIAL GRADIENT AT K = 14.2566

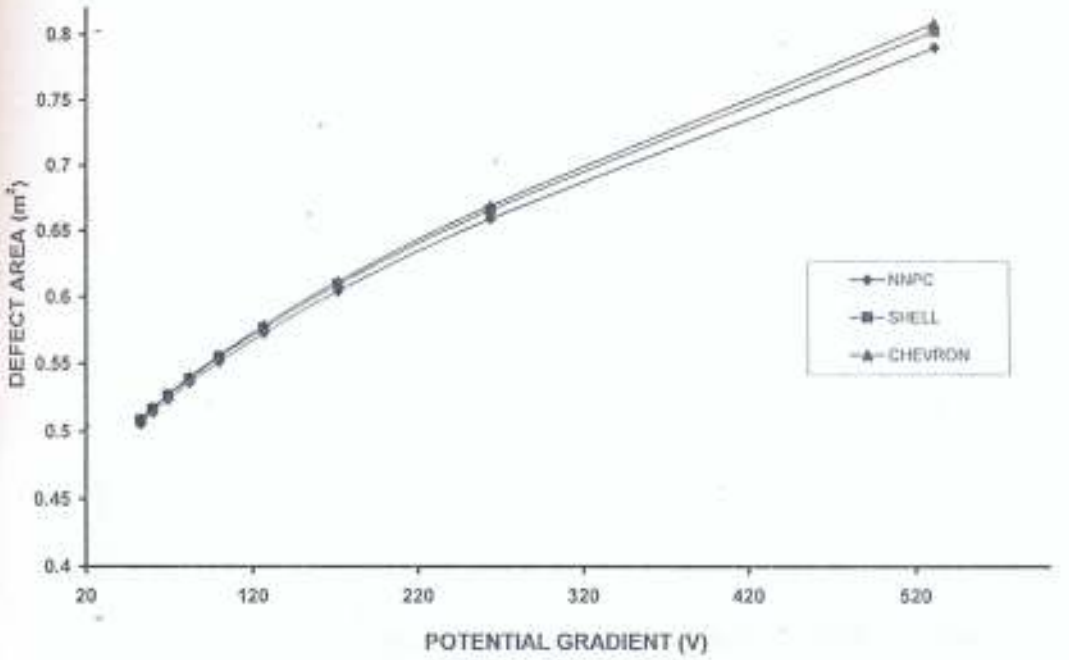


FIGURE 28: PLOT OF DEFECT AREA AGAINST POTENTIAL GRADIENT AT K = 38.9501

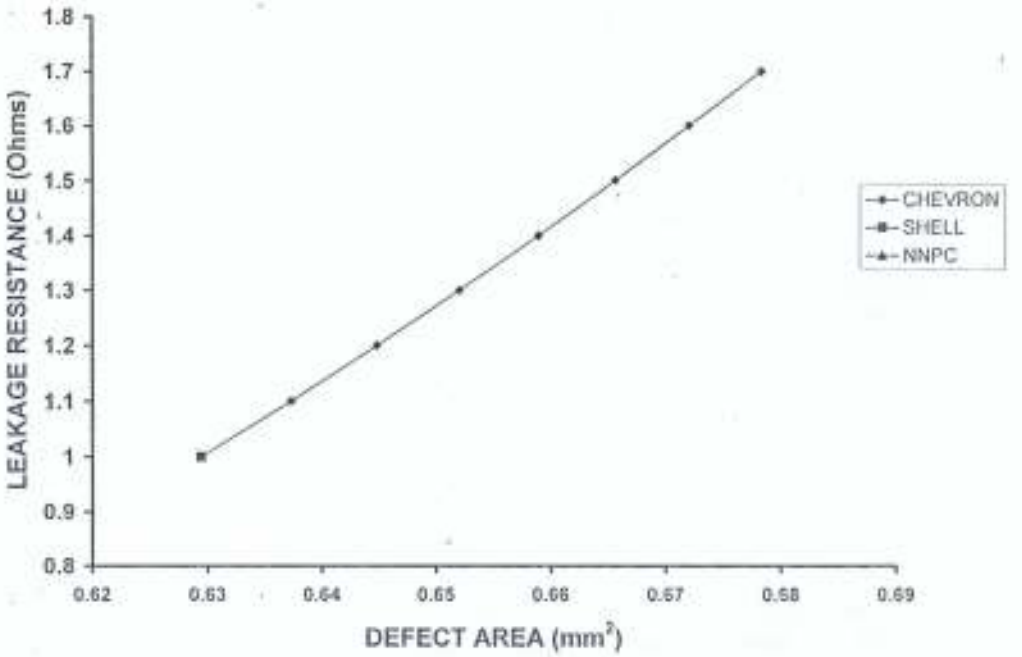


FIGURE 29: PLOT OF LEAKAGE RESISTANCE AGAINST DEFECT AREA AT K = 4.37039

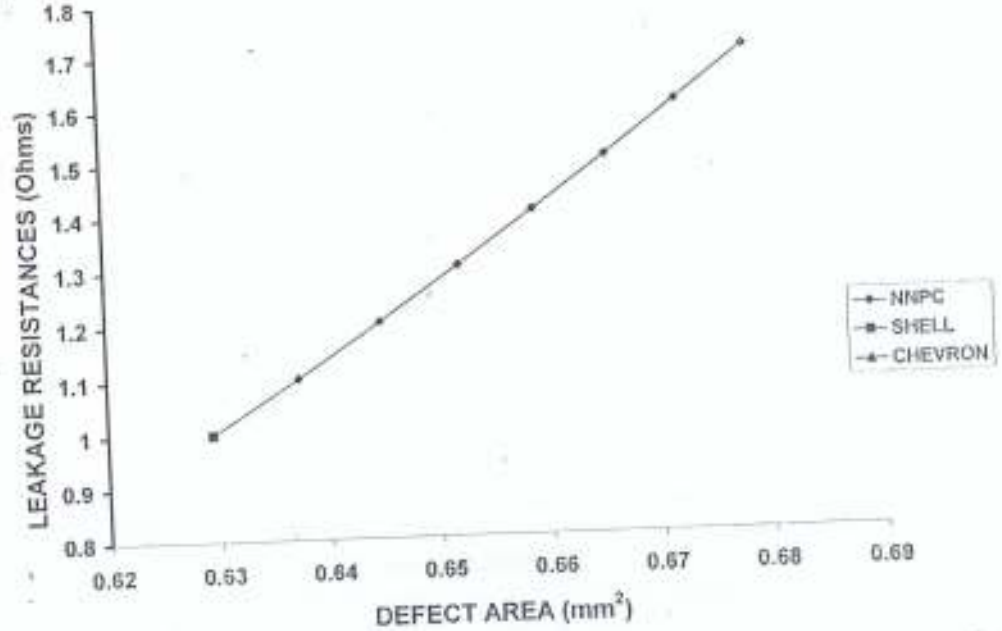


FIGURE 30: PLOT OF LEAKAGE RESISTANCE AGAINST DEFECT AREA AT K = 14.2566

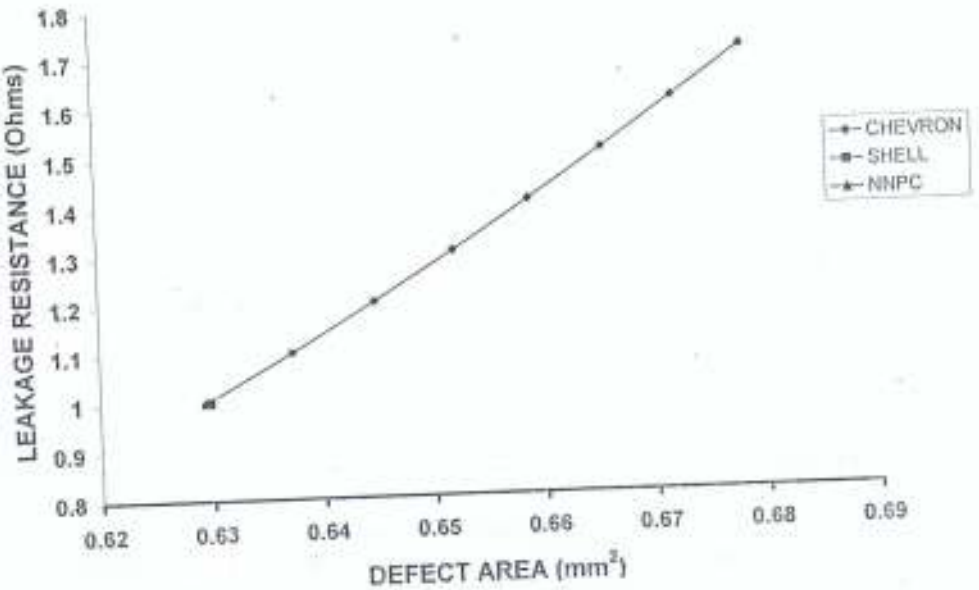


FIGURE 31: PLOT OF LEAKAGE REISTANCE AGAINST DEFECT AREA AT K = 38.9501

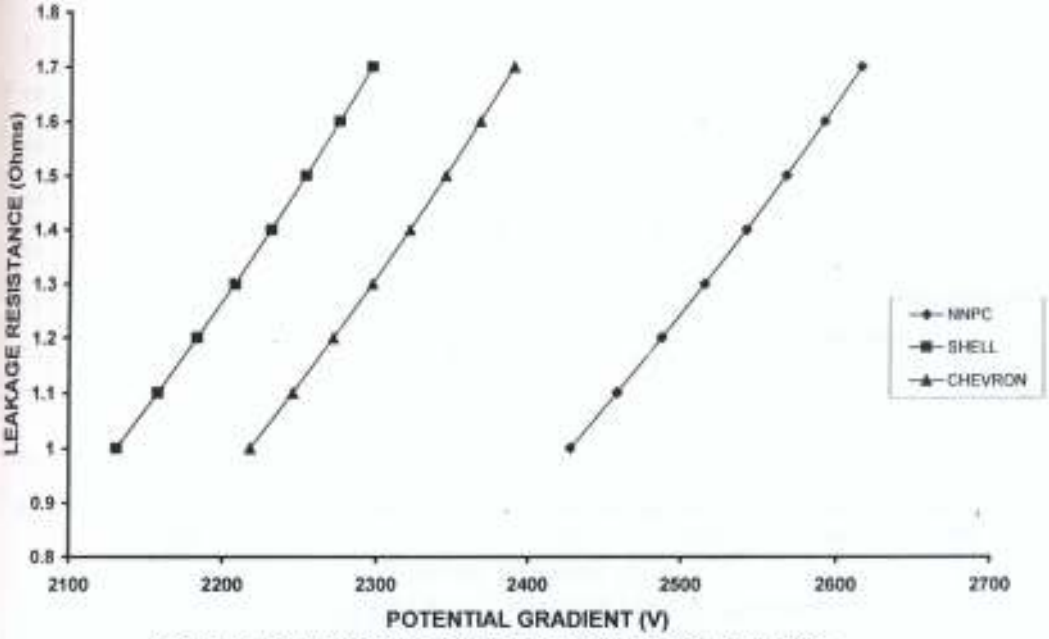


FIGURE 32: PLOT OF LEAKAGE RESISTANCE AGAINST POTENTIAL GRADIENT AT K = 4.37039

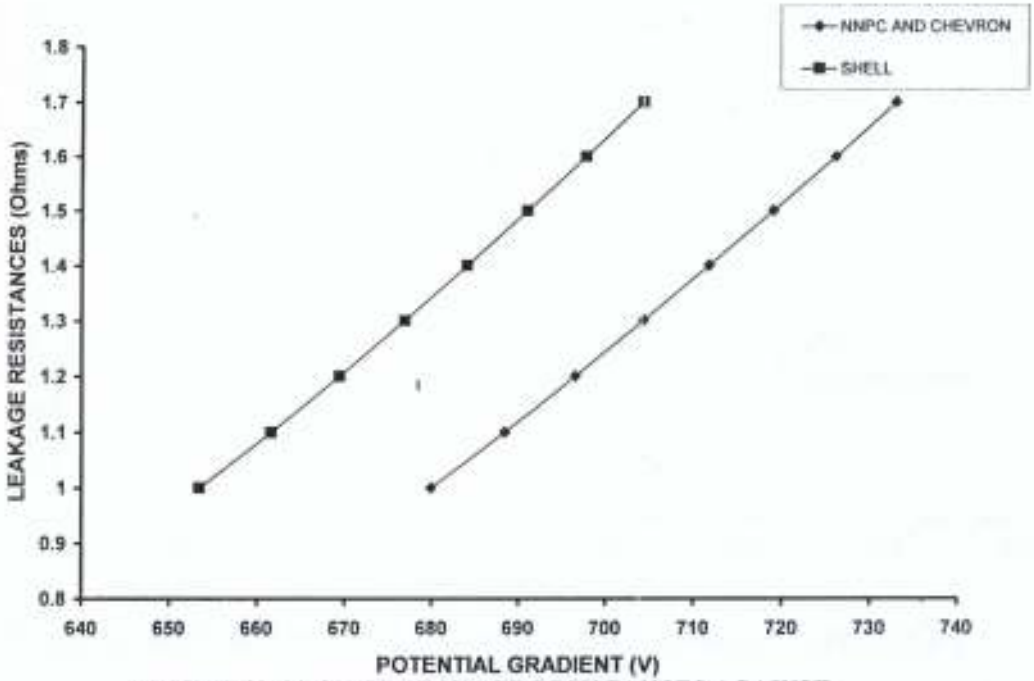


FIGURE 33: PLOT OF LEAKAGE RESISTANCES AGAINST POTENTIAL GRADIENT AT K = 14.2566

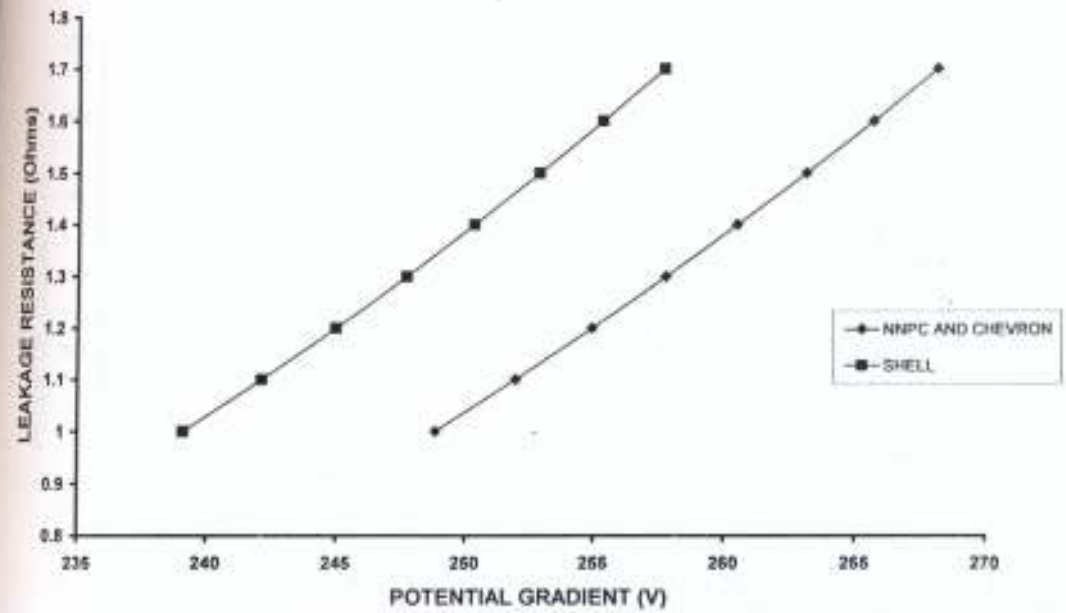


FIGURE 34: PLOT OF LEAKAGE RESISTANCE AGAINST POTENTIAL GRADIENT AT K = 38.9501

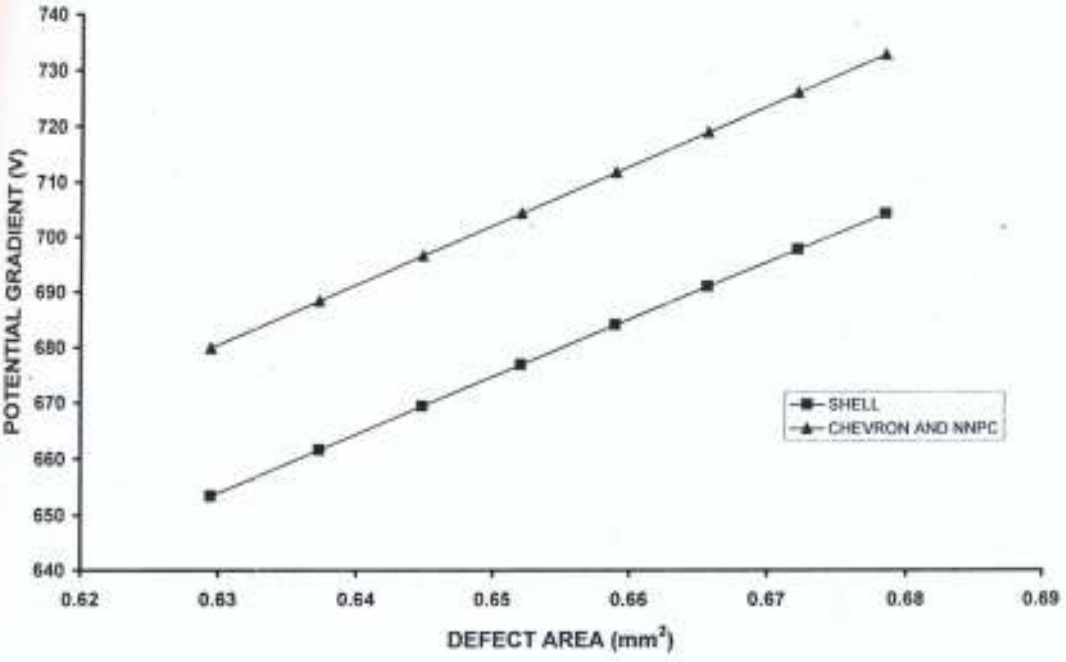


FIGURE 35: PLOT OF POTENTIAL GRADIENT AGAINSST DEFECT AREA AT K = 14.2566

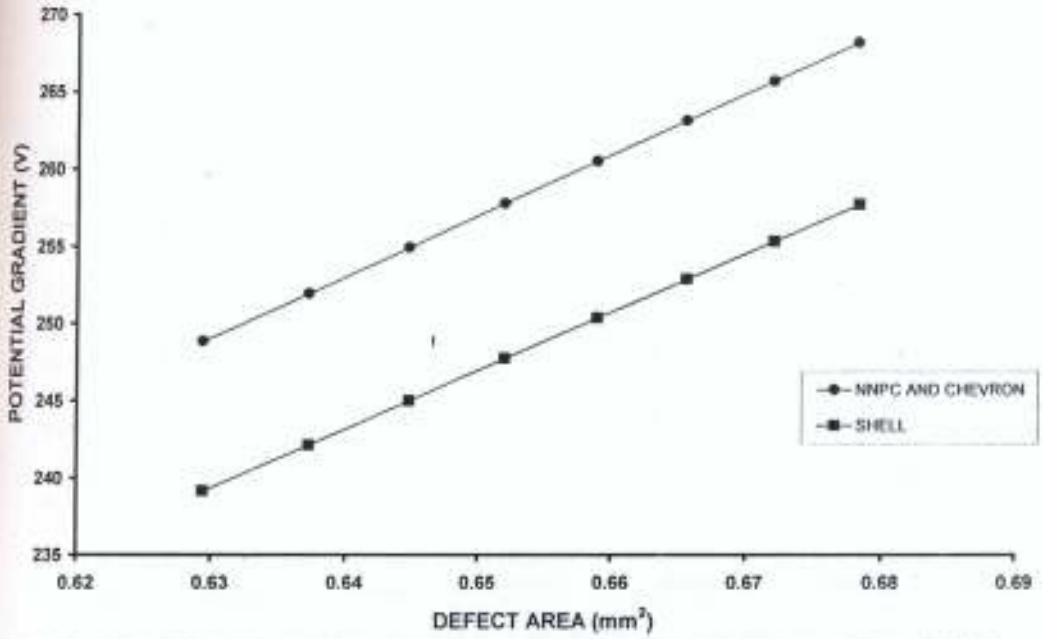


FIGURE 36: PLOT OF POTENTIAL GRADIENT AGAINST DEFECT AREA AT K = 38.9501

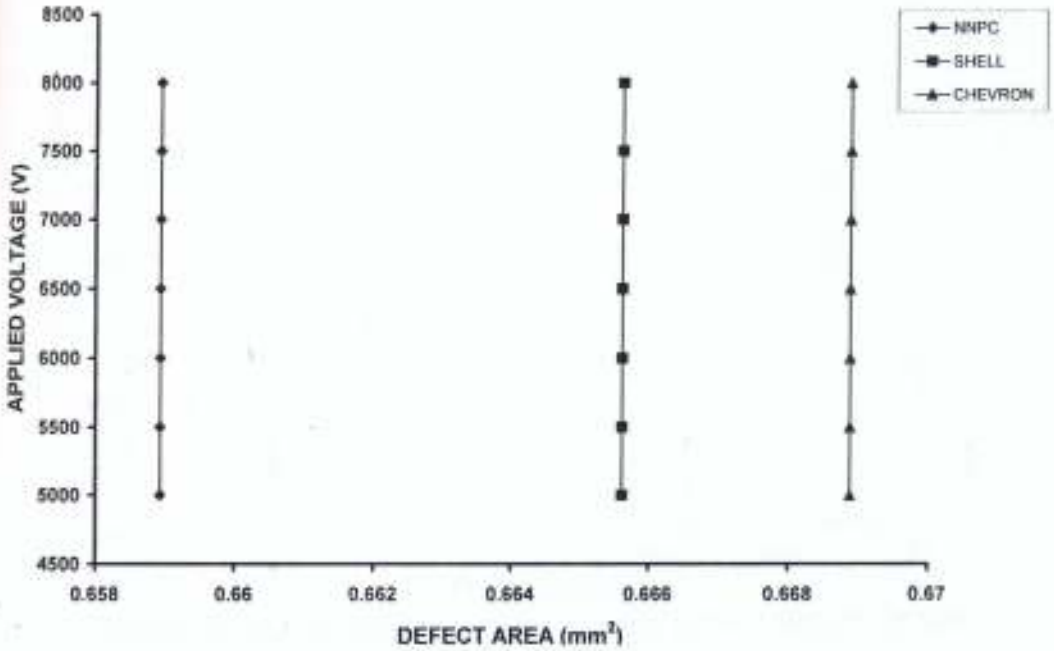


FIGURE 37: PLOT OF APPLIED VOLTAGE AGAINST DEFECT AREA AT K = 4.37039

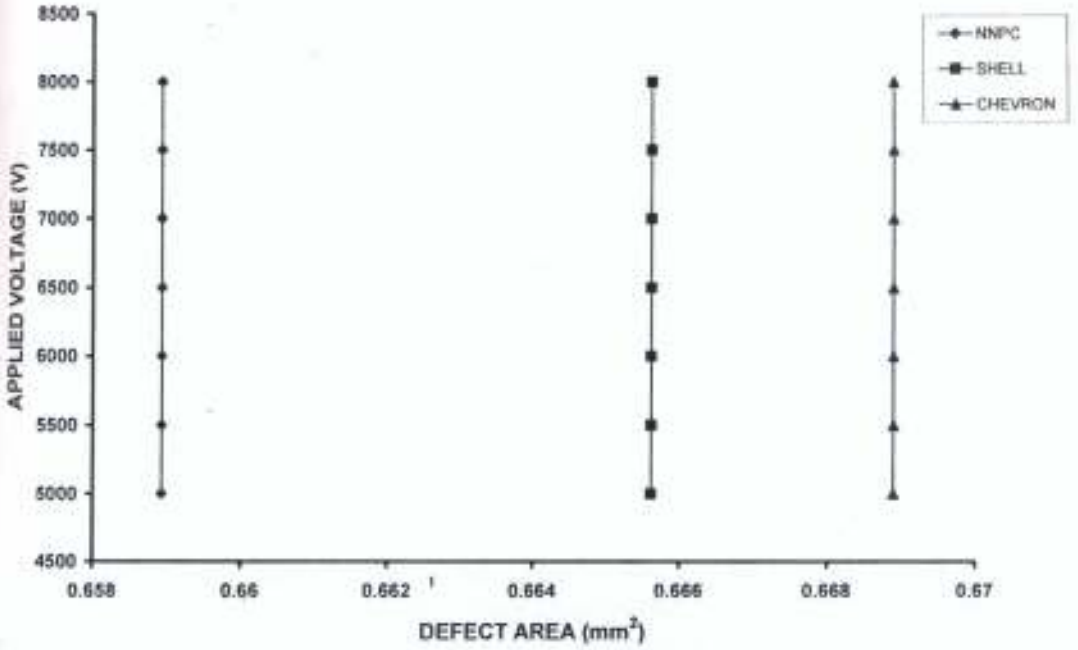


FIGURE 38: PLOT OF APPLIED VOLTAGE AGAINST DEFECT AREA AT K = 14.2566

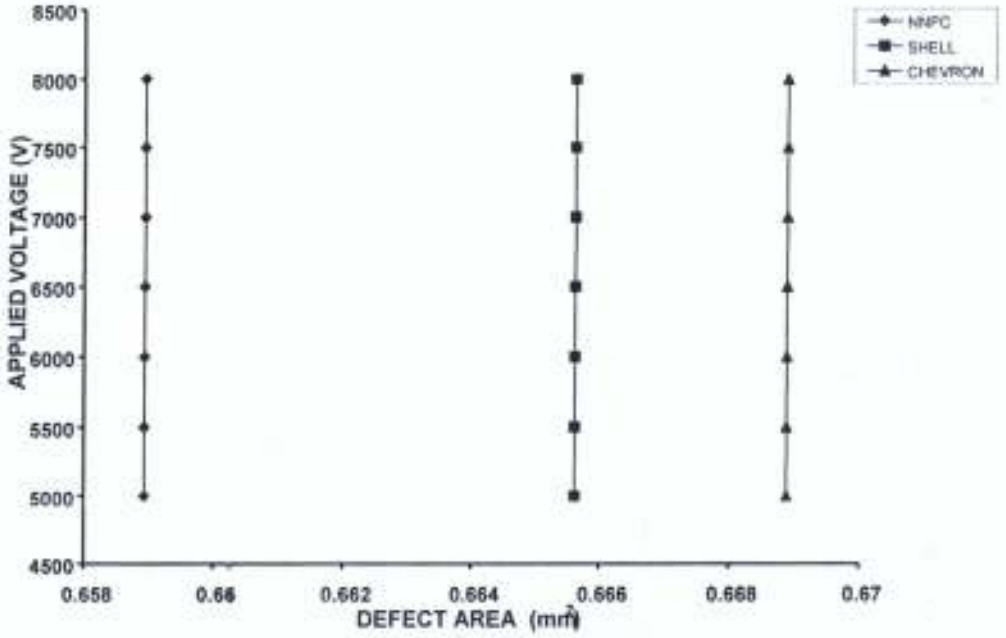


FIGURE 39: PLOT OF APPLIED VOLTAGE AGAINST DEFECT AREA K = 38.9501

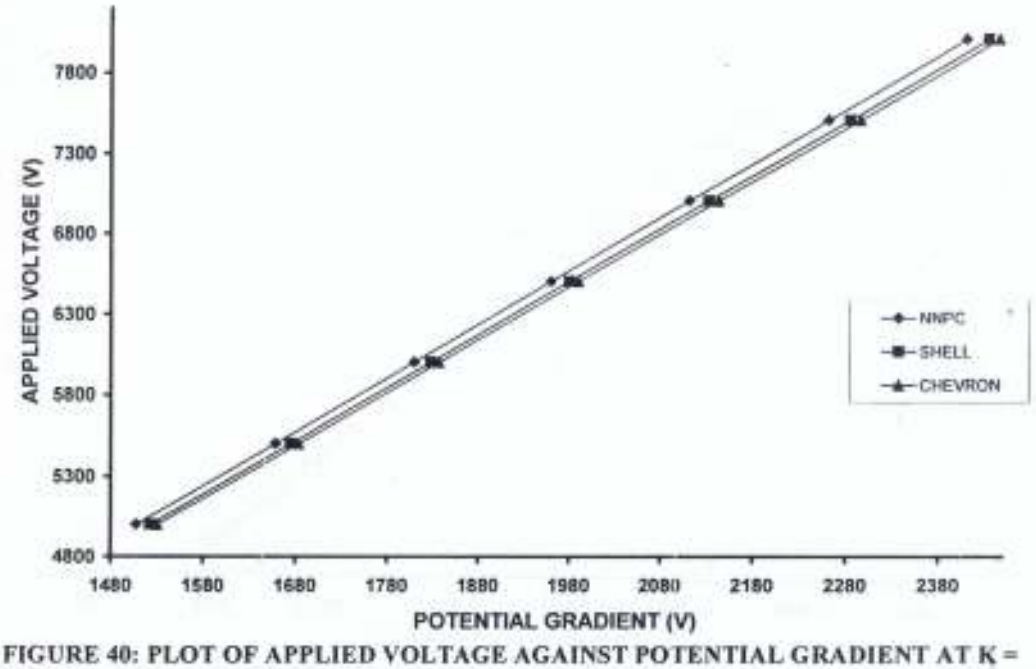


FIGURE 40: PLOT OF APPLIED VOLTAGE AGAINST POTENTIAL GRADIENT AT K = 4.37039

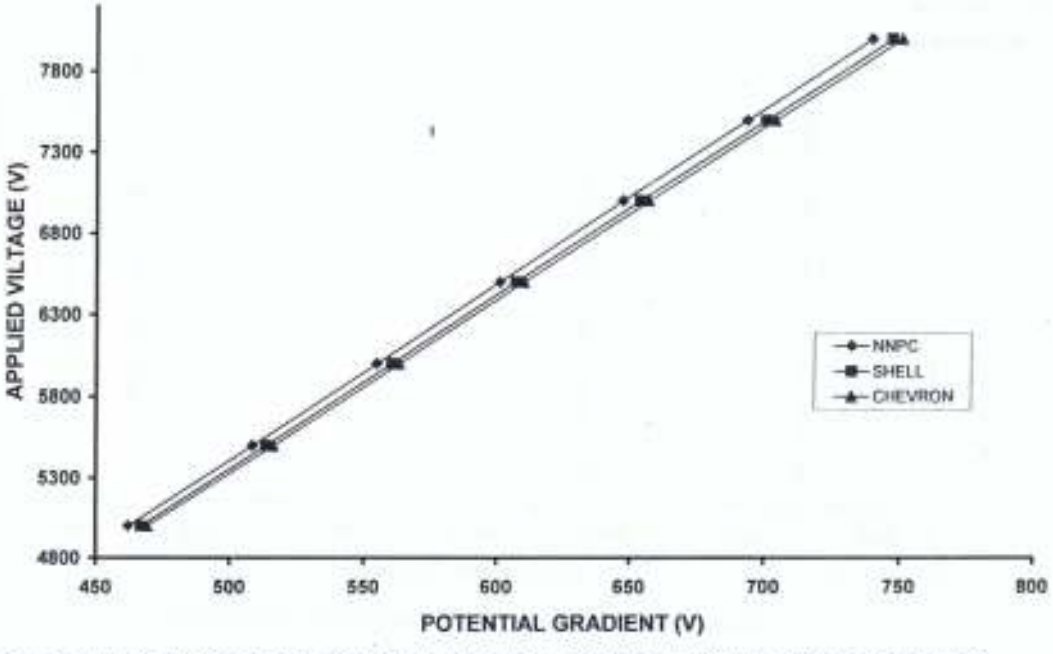


FIGURE 41. PLOT OF APPLIED VOLTAGE AGAINST POTENTIAL GRADIENT AT K =14.2566

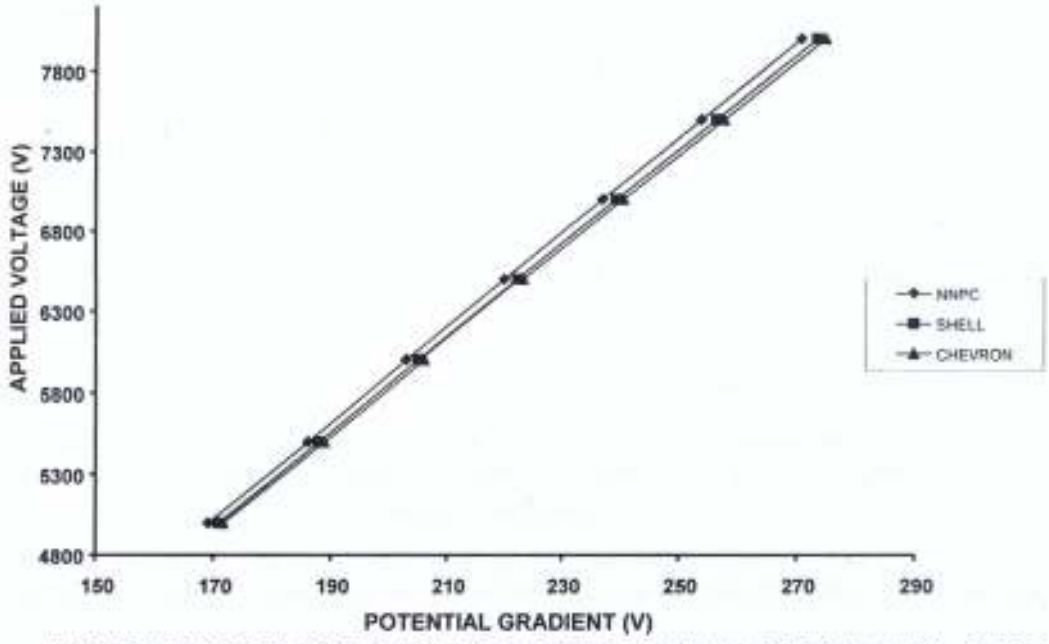
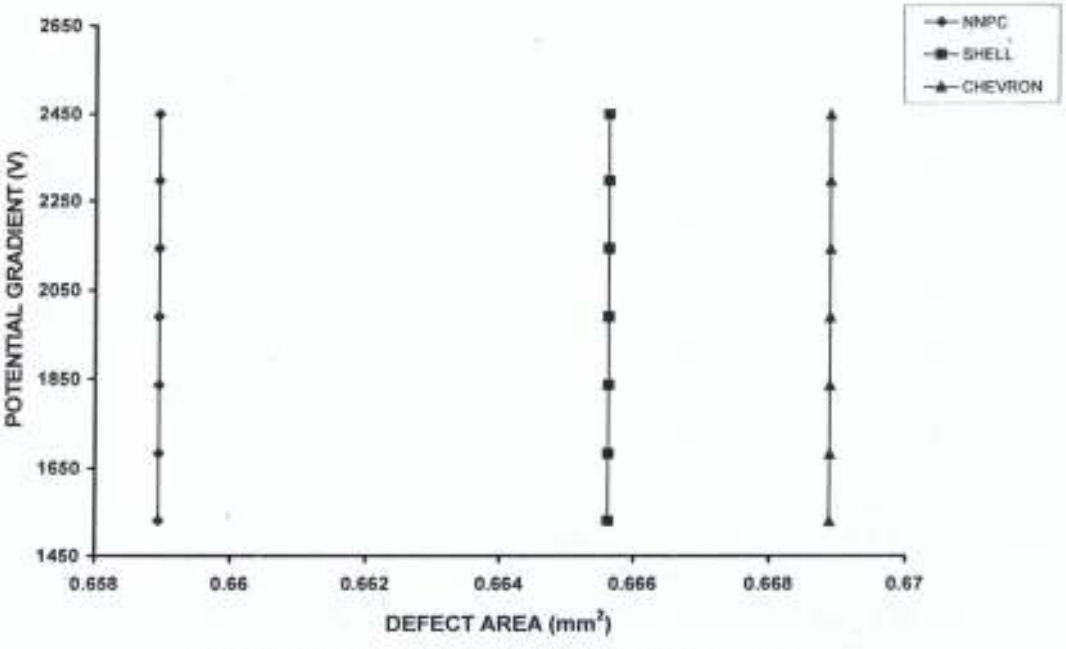


FIGURE 42: PLOT OF APPLIED VOLTAGE AGAINST POTENTIAL GRADEINT AT K = 38.9501



POTENTIAL GRADIENT, VS DEFECT AREA AT K = 4.3703

FIGURE 43: PLOT OF POTENTIAL GRADIENT AGAINST DEFECT AREA AT K = 4.3703

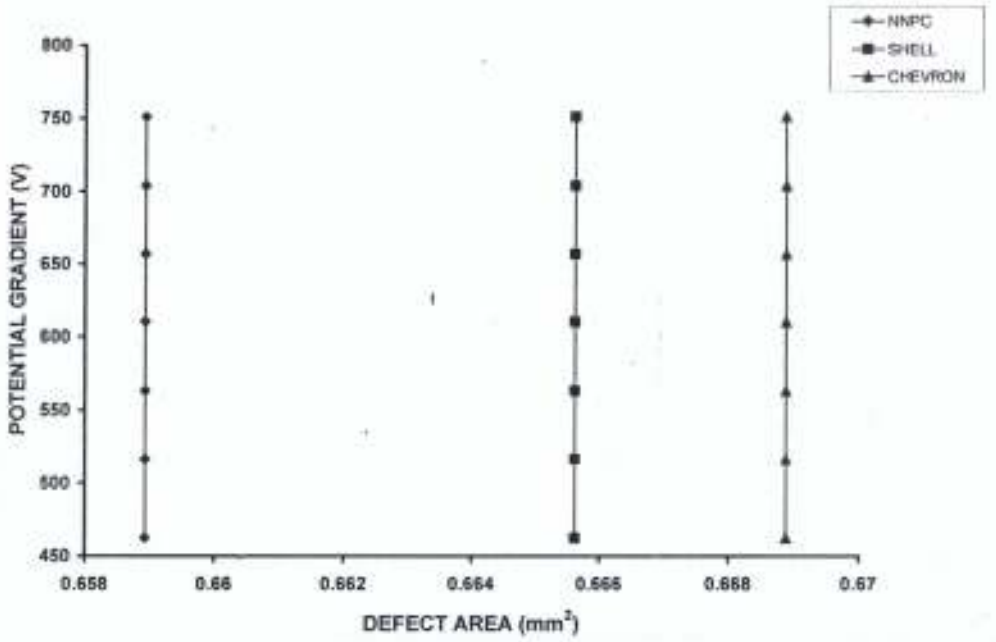


FIGURE 44: PLOT OF POTENTIAL GRADIENT AGAINST DEFECT AREA AT K =14.2566

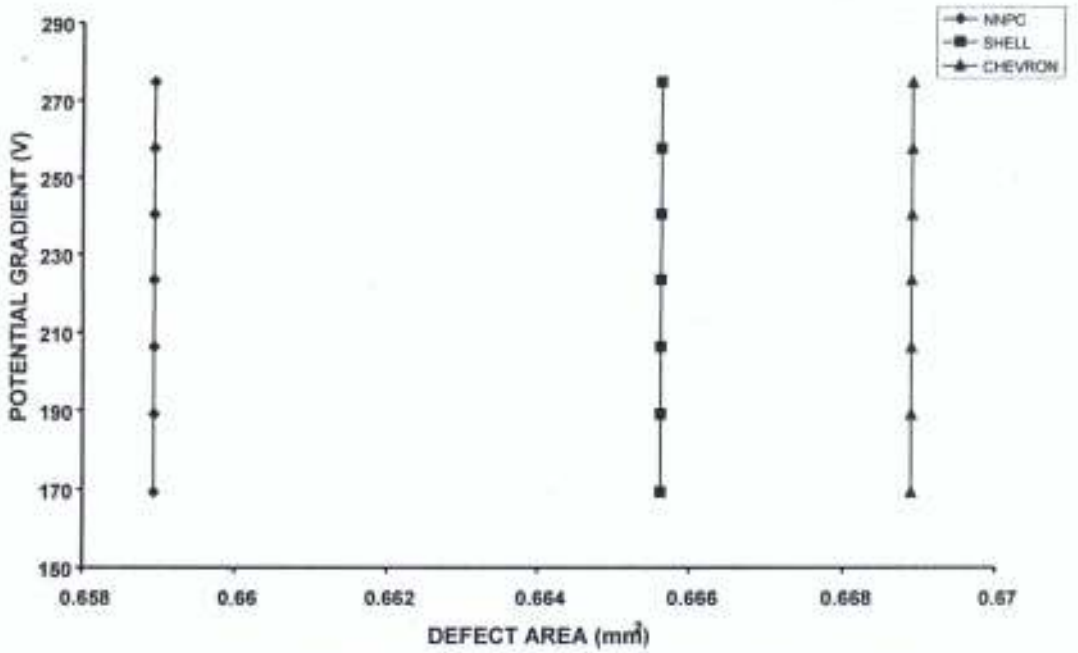


FIGURE 45: A PLOT OF POTENTIAL GRADIENT AGAINST DEFECT AREA K = 38.9501

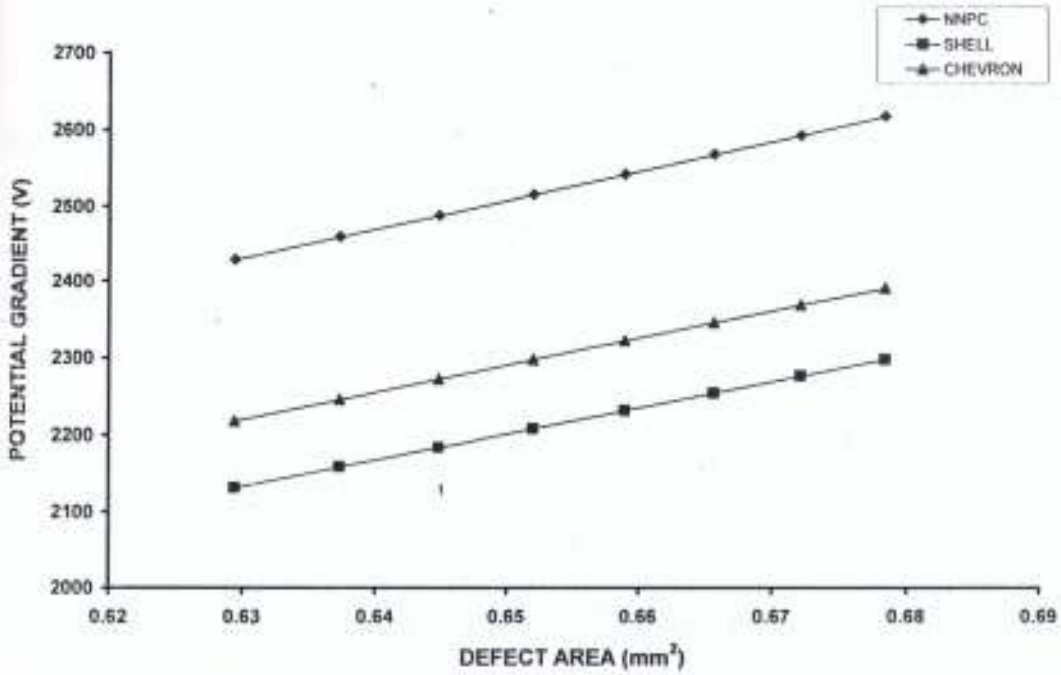


FIGURE 46: PLOT OF POTENTIAL GRADIENT AGAINST DEFECT AREA AT K = 4.37039

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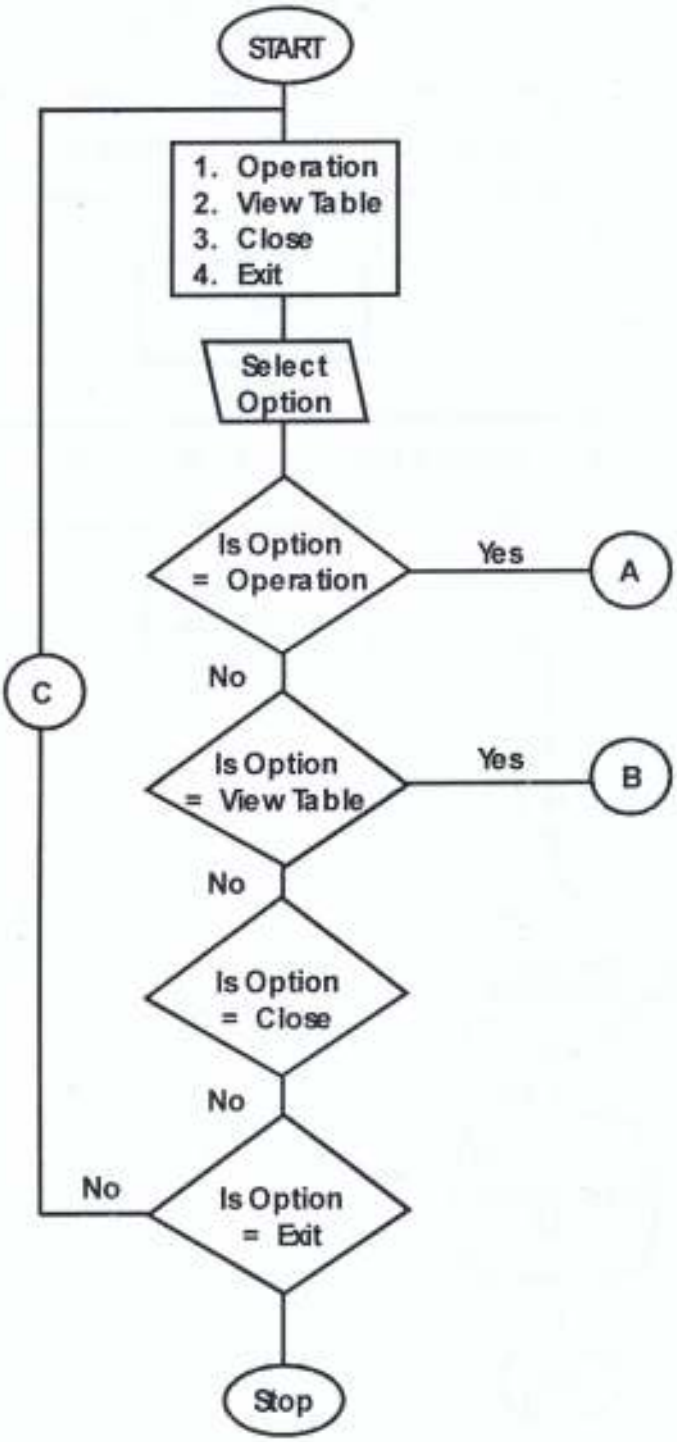
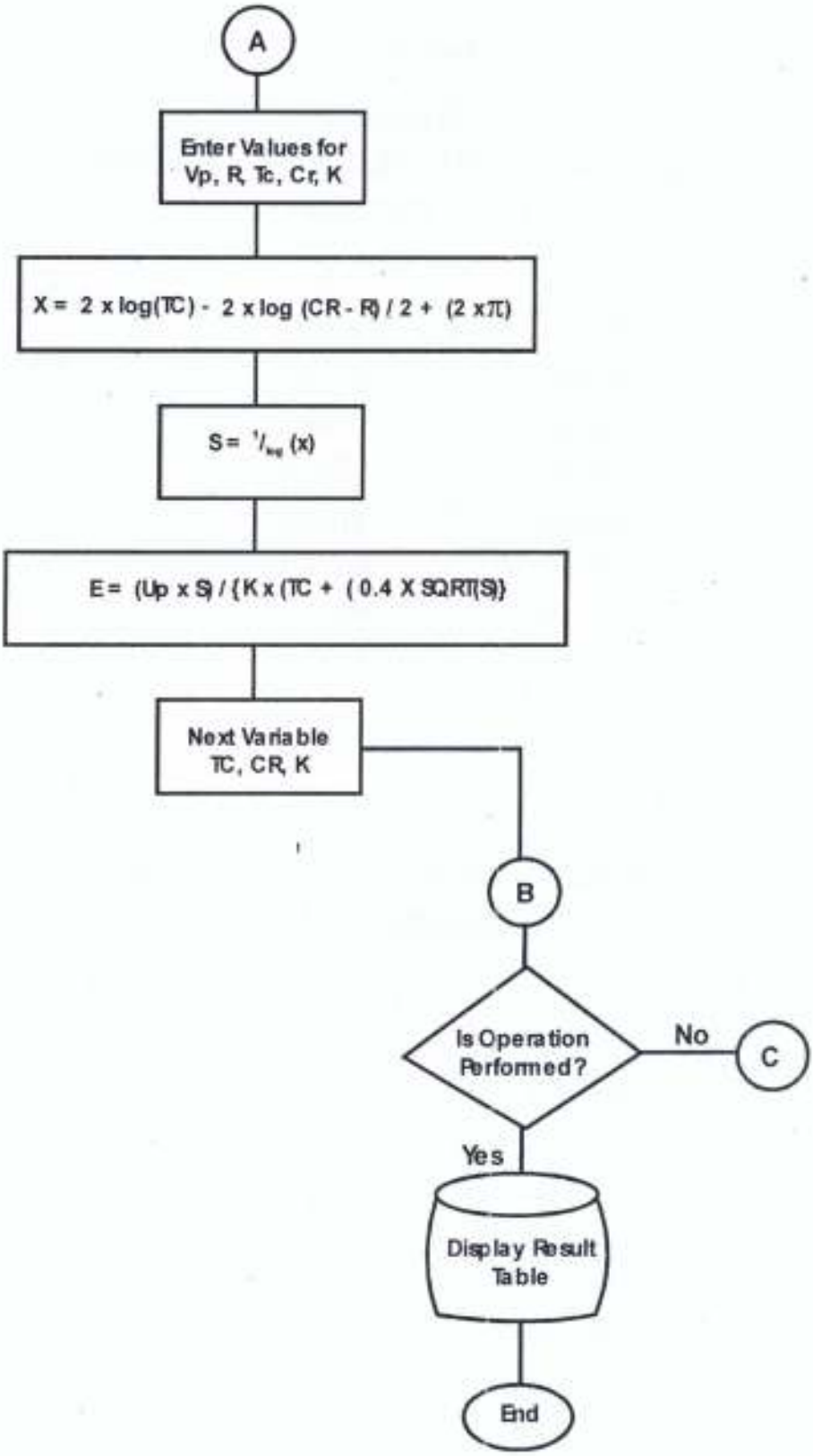
'*************************************************************************
' THIS PROGRAMM FINDS RELATIONSHIP BETWEEN
' COATING DEFECT AREA "S" AND POTENTIAL GRADIENT "E"
' FOR NNPC, SHELL AND CHEVRON AT VARYING COATING THICKNESS TC.
' GIVEN THE FOLLOWING VARIABLES:
' VP = SIGNAL POTENTIAL, K = BURIAL DEPTH, TC = COATING THICKNESS
' CR = COATING RESISTANCE, AND R = RESISTIVITY OF STEEL PIPE
'
 VP = 8400!: R = 6.22E-06: K = 157000!: CR = 1.4
INT TAB(33); "RESULT ANALYSIS"
INT TAB(33); "---------------"
INT TAB(30); "RELATIONSHIP BETWEEN"
INT TAB(30); "----------------------"
OR I = 1 TO 3
 IF I = 1 THEN 145
 IF I = 2 THEN 180
 IF I = 3 THEN 220
 PRINT
PRINT TAB(15); "COATING DEFECT AREA 'S AND POTENTIAL GRADIENT E FOR NNP
PRINT TAB(15); "-----------------------------------------------------
GOTO 260
LET CR = 1.5: VP = 7400!: R = .0000062
PRINT
PRINT TAB(15); "COATING DEFECT AREA S AND POTENTIAL GRADIENT E FOR SHE
PRINT TAB(15); "-----------------------------------------------------
GOTO 260
LET CR = 1.55: VP = 7700!: R = .0000064
PRINT
RINT TAB(15); "COATING DEFECT AREA S AND POTENTIAL GRADIENT E FOR CHEVR
RINT TAB(15); "-----------------------------------------------------
RINT TAB(10); "TC"; TAB(33); "S"; TAB(53); "E"
RINT TAB(10); "-"; TAB(33); "-"; TAB(53); "-"
OR tc = .1 TO 2 STEP .2
 X = 2 * LOG(tc) - (2 * LOG(CR - R)) / 2 + (2 * 3.142)
 s = 1 / LOG(X)
 E = (VP * s) / (K * (tc + (.4 * SQR(s))))
 PRINT TAB(8); tc; TAB(29); s; TAB(48); E
EXT tc
PRINT
PRINT "Press ENTER Key to cont..."
DO
LOOP UNTIL INKEY$ = CHR$(13)
EXT I
 FOR FT = 1 TO 3
   IF FT = 1 THEN VP = 1E-10: K = 1E-10: CR = 1!
   IF FT = 2 THEN VP = 2E-10: K = 100000!: CR = 1.3
   IF FT = 3 THEN VP = 3E-10: K = 200000!: CR = 1.6
   CLS
PRINT TAB(15); "COATING DEFECT AREA S AND POTENTIAL GRADIENT E "
PRINT TAB(15); "-----------------------------------------------"
PRINT TAB(10); "TC"; TAB(33); "S"; TAB(53); "E"
PRINT TAB(10); "-"; TAB(33); "-"; TAB(53); "-"
FOR tc = .1 TO 2 STEP .2
  X = 2 * LOG(tc) - (2 * LOG(CR - R)) / 2 + (2 * 3.142)
  s = 1 / LOG(X)
  E = (VP * s) / (K * (tc + (.4 * SQR(s))))
  PRINT TAB(8); tc; TAB(29); s; TAB(48); E
NEXT tc
PRINT
PRINT "Press ENTER Key to cont..."
DO
LOOP UNTIL INKEY$ = CHR$(13)
CLS
NEXT FT
```

APPENDIX I

THE ALGORITHM OF THE COMPUTER PROGRAM




A
Enter Values for Vp, R, Tc, Cr, K
X = 2 x log(TC) - 2 x log (CR - R) / 2 + (2 x π)
S = 1/sq (x)
E = (Up x S) / {K x (TC + (0.4 X SQRT(S)}
Next Variable TC, CR, K
B
Is Operation Performed?
No
C
Yes
Display Result Table
End

APPENDIX II

A. RESULT ANALYSIS WHEN K = 4.3703

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

Tc	S	E
.1	3.396384	65513.85
.3	.791133	5086.799
.5	.6589378	2542.089
.7	.6041527	1664.812
.9	.524415	1226.888
1.1	.5511088	966.409
1.3	.5354679	794.5229
1.5	.5233423	672.9935
1.7	.5135671	582.7263
1.9	.5054563	513.1523

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

Tc	S	E
.1	4.137442	70057.14
.3	.8036413	4535.879
.5	.6656191	2254.116
.7	.6090323	1473.204
.9	.5764318	1084.491
1.1	.5545616	853.6455
1.3	.5385569	701.4693
1.5	.5261662	593.9531
1.7	.5161883	514.1379
1.9.	.5079162	452.6462

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

Tc	S	E
.1	4.638688	81728.7
.3	.8098263	4756.09
.5	.6688845	2357.005
.7	.6114064	1538.904
.9	.5783683	1132.248
1.1	.5562345	890.9324
1.3	.5400518	731.9333
1.5	.5275317	619.6362
1.7	.5174547	536.2939
1.9	.509104	472.0982

B. RESULT ANALYSISWHEN K = 14.2566

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

Tc	S	E
.1	3.396383	18343.89
.3	.791133	1424.305
.5	.6589378	711.7855
.7	.6041527	466.1476
.9	.5724415	343.5289
1.1	.5511088	270.5948
1.3	.5354679	222.4666
1.5	.5233423	188.4383
1.7	.5135671	163.1635
1.9	.5054563	143.6828

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

Tc	S	E
.1	4.137442	21475.72
.3	.8036413	1390.454
.5	.6656191	690.9896
.7	.6090323	51.6043
.9	.5764318	332.446
1.1	.5545616	261.6814
1.3	.5385569	215.0324
1.5	.5261662	182.0738
1.7	.5161883	157.6068
1.9	.5079162	138.7567

C. RESULT ANALYSIS WHEN K = 38.9501

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

Tc	S	E
.1	3.396383	6714.27
.3	.791133	521.3272
.5	.6589378	260.5293
.7	.6041527	170.6204
.9	.5724415	125.7392
1.1	.5511088	99.04369
1.3	.5354679	81.42771
1.5	.5233423	68.97261
1.7	.5135671	59.72146
1.9	.5054563	52.59108

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

Tc	S	E
.1	4.137442	7860.588
.3	.8036413	508.9371
.5	.6656191	252.9175
.7	.6090323	165.2972
.9	.5764318	121.6826
1.1	.5545616	95.78119
1.3	.5385569	78.70663
1.5	.5261662	66.64304
1.7	5161883	57.68758
1.9	.5075962	50.78805

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

Tc	S	E
.1	4.638688	9170.168
.3	.8098263	533.6453
.5	.6688845	264.462
.7	.6114064	172.6689
.9	.5783683	127.0411
1.1	.5562345	99.96487
1.3	.5400518	82.12477
1.5	.5275317	69.52474
1.7	.5174547	60.17354
1.9	.509104	52.97062

D. RESULT ANALYSIS WHEN K = 4.3703

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

CR	S	E
1	.6294185	2428.208
1.1	.6373015	2458.619
1.2	.6448154	2487.607
1.3	.6520134	2515.375
1.4	.6589378	2542.089
1.5	.6656228	2567.879
1.6	.6720965	2592.854
1.7	.6783825	2617.104

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

CR	S	E
1	.629414	2131.508
1.1	.6372972	2158.204
1.2	.6448113	2183.651
1.3	.6520094	2208.027
1.4	.658934	2231.477
1.5	.6656191	2254.116
1.6	.672093	2276.04
1.7	.678329	2297.327

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

CR	S	E
1	.6294185	2217.936
1.1	.6373015	2245.714
1.2	.6448154	2272.191
1.3	.6520134	2297.555
1.4	.6589378	2321.955
1.5	.6656228	2345.512
1.6	.6720965	2368.324
1.7	.6783824	2390.474

E. RESULT ANALYSIS WHEN K = 14.2566

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

CR	S	E
1	.6294185	679.8987
1.1	.6373015	688.414
1.2	.6448154	696.5305
1.3	.6520134	704.3058
1.4	.6589378	711.7855
1.5	.6656228	719.0067
1.6	.6720965	725.9996
1.7	.6783824	732.7896

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

CR	S	E
1	.629414	653.4045
1.1	.6372972	661.5882
1.2	.6448113	669.3887
1.3	.6520094	676.8612
1.4	.658934	684.0497
1.5	.6656191	690.9896
1.6	.672093	697.7103
1.7	.678379	704.2358

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

CR	S	E
1	.6294185	679.8987
1.1	.6373015	688.414
1.2	.6448154	696.5305
1.3	.6520134	704.3058
1.4	.6589378	711.7855
1.5	.6656228	719.0067
1.6	.6720965	725.9996
1.7	.6783824	732.7896

F. RESULT ANALYSIS WHEN K=38.9501

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

CR	S	E
1	.6294185	248.858
1.1	.6373015	251.9748
1.2	.6448154	254.9456
1.3	.6520134	257.7915
1.4	.6589378	260.5293
1.5	.6656228	263.1724
1.6	.6720965	265.7319
1.7	.6783824	268.2173

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

CR	S	E
1	.629414	239.1605
1.1	.6372972	242.156
1.2	.6448113	245.0111
1.3	.6520094	247.7462
1.4	.658934	250.3774
1.5	.6656191	252.9175
1.6	.672093	255.23774
1.7	.678379	257.7659

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

CR	S	E
1	.6294185	248.858
1.1	.6373015	251.9748
1.2	.6448154	254.9456
1.3	.6520134	257.7915
1.4	.6589378	260.5293
1.5	.6656228	263.1724
1.6	.6720965	265.7319
1.7	.6783824	268.2173

G. RESULT ANALYSIS WHEN K=4.3703

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

VP	S	E
5000	.6589378	1507.763
5500	.6589378	1658.54
6000	.6589378	1809.316
6500	.6589378	1960.092
7000	.6589378	2110.869
7500	.6589378	2261.645
8000	.6589378	2412.421

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

VP	S	E
5000	.6656191	1523.051
5500	.6656191	1675.356
6000	.6656191	1827.661
6500	.6656191	1979.967
7000	.6656191	2132.272
7500	.6656191	2284.577
8000	.6656191	2436.882

(3) **COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON**

VP	S	E
5000	.6688845	1530.523
5500	.6688845	1683.575
6000	.6688845	1836.628
6500	.6688845	1989.68
7000	.6688845	2142.732
7500	.6688845	2295.785
8000	.6688845	2448.837

H. RESULT ANALYSIS WHEN K=14.2566

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR NNPC

VP	S	E
5000	.6589378	462.1984
5500	.6589378	508.4182
6000	.6589378	554.6381
6500	.6589378	600.8579
7000	.6589378	647.0777
7500	.6589378	693.2975
8000	.6589378	739.5174

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR SHELL

VP	S	E
5000	.6656191	466.8849
5500	.6656191	513.5734
6000	.6656191	560.2618
6500	.6656191	606.9503
7000	.6656191	653.6388
7500	.6656191	700.3273
8000	.6656191	747.0157

(3) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON

VP	S	E
5000	.6688845	469.1753
5500	.6688845	516.0928
6000	.6688845	563.0103
6500	.6688845	609.9279
7000	.6688845	656.9279
7500	.6688845	703.7629
8000	.6688845	750.6805

I. RESULT ANALYSIS WHEN K=38.9501

RELATIONSHIP BETWEEN

(1) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E)

FOR NNPC

VP	S	E
5000	.6589378	169.1749
5500	.6589378	186.0923
6000	.6589378	203.0098
6500	.6589378	219.9273
7000	.6589378	236.8448
7500	.6589378	253.7623
8000	.6589378	270.6798

(2) COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E)

FOR SHELL

VP	S	E
5000	.6656191	170.8902
5500	.6656191	187.9792
6000	.6656191	205.0683
6500	.6656191	222.1573
7000	.6656191	239.2463
7500	.6656191	256.3353
8000	.6656191	273.4243

(3) **COATING DEFECT AREA (S) AND POTENTIAL GRADIENT (E) FOR CHEVRON**

VP	S	E
5000	.6656191	171.7286
5500	.6656191	188.9014
6000	.6656191	206.0743
6500	.6656191	223.2471
7000	.6656191	240.42
7500	.6656191	257.5928
8000	.6656191	274.7657