MAINTENANCE OF PIPELINE SYSTEM

(Final Project Report)

Submitted for Partial Fulfillment of the

B-Tech. Degree

(APPLIED PETROLEUM ENGINEERING)

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CERTIFICATE

This is to certify that the project work on *"MAINTENANCE OF PIPELINE SYSTEM"* submitted to University of Petroleum & Energy Studies, Dehradun, by Ms. Nidhi Pandey and Seema Bedwal, in partial fulfillment of the requirement for the award of Degree of Bachelor of Technology in Applied Petroleum Engineering (Academic Session 2003 – 2007) is a bonafide work carried out by them under my supervision and guidance. This work has not been submitted anywhere else for any other degree or diploma.

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LIST OF CONTENTS

LIST OF FIGURES

PROJECT ABSTRACT

No matter how well pipelines are designed, constructed and operated, they are subject to deterioration, externally and internally, direct and/or indirectly. Consequently to ensure continued successful business operation, maintenance activities must be performed on the pipeline on a routine basis. There are also activities that concerns emergency situation such as the case of pipeline rupture due to unforeseen circumstances of environmental and geotechnical activities, third party damage etc. Maintenance activities can therefore be divided into two groups: routine maintenance and emergency response activities. Pipeline maintenance consists of:

- Routine monitoring such as:
    - Patrol and leak
    - Environmental protection, including vegetation management
    - Cathodic protection
    - Depth of cover
    - Encroachment assessment
    - Overall facilities integrity assessment to identify problem areas for focusing management efforts.
    - ROW maintenance
    - Pipeline failure and rupture.

There are also maintenance activities that are not usually routine in nature, but are preformed as consequences of undertaking routine management, such as excavation, to assess external corrosion damage. These include:

- Trenching and excavation
- Locating pipeline
- Blasting
- Foreign crossing
- Pipeline integrity assessment
- Pipeline repair and modification
- Welding

CHAPTER – 1

MAINTENANCE –A PERSPECTIVE

1.1 IMPORTANCE OF MAINTENANCE

Maintenance is an important part of the life-cycle of embedded systems, and must be considered from the design stage through the end-of-life stage of the system. Maintenance covers two aspects of systems - operation and performance. Maintenance is generally performed in anticipation of, or in reaction to, a failure. Maintenance is performed to ensure or restore system performance to specified levels. Improperly performed or timed maintenance can exacerbate problems because of faulty parts, maintainer error, or decreased profits. A systematic and structured approach to system maintenance, starting during the design process, is necessary to ensure proper and cost-effective maintenance.

Maintenance of any kind performed on a system is a consequence of the fact that systems (or components) deteriorate and fail. Any product or system that has maintenance directions or procedures has an implicit statement that there is a non-zero probability that the system could at some point operate outside its specified parameters.

General principles

The following aspects should be considered with respect to Maintenance Procedures:

- Human factors;
- Poorly skilled work force;
- Unconscious and conscious incompetence;
- Good maintainability principles;
- Knowledge of failure rate and maintainability; and
- Clear criteria for recognition of faults and marginal performance.

The following issues may contribute towards a major accident or hazard:

- Failure of safety critical equipment due to lack of maintenance;
- Human error during maintenance;
- Static or spark discharge during maintenance in an intrinsically safe zone;
- Incompetence of maintenance staff; and
- Poor communication between maintenance and production staff.

Repair or Replace

Economic benefits of disposal and repair are often approached most easily from an accounting point of view. If the cost of designing for maintenance is much higher than the cost of not doing so, and the applications in which the product will be used are such that replacement is feasible, then disposal may be a viable option. Considerations about the expected lifetime of the system must be taken into account as well. It may in fact be cheaper, over the expected lifetime of a product, to design for maintenance, instead of having to maintain inventories of replacements, which may never be used. On a system level, mechanical systems are virtually always repaired rather than disposed and replaced, because of the cost associated. Electronic systems are sometimes repaired, but often that repair is done through the disposal and replacement of a subassembly or component. Electronic components are virtually impossible to repair in a cost-effective manner, while larger numbers of mechanical components are. On a related note, regulatory agencies may require replacement of failed or degraded components, instead of repair, because of the failure modes associated with the components or their criticality in the system.

Personnel

The issue of who performs maintenance when it is necessary is an important one from the point of view of profits. There are endless variations on who can perform what maintenance how and when, but three common situations will be covered. The first approach is for the owner or user of the system to perform the maintenance themselves. In a safety-critical system, this may not be allowed unless the owner has special maintenance training or certification, or hires a suitably trained or certified third party to perform the maintenance. A second approach is for the producer of the system to have an in-house maintenance staff which performs all maintenance, either at the system's location or on the producer's premises. If the maintainers and the designers work closely together, this approach generally results in the highest quality maintenance. People knowledgeable about the design and functionality of the system are arguably best qualified to maintain it. A third approach is for a third-party to provide maintenance. Safety-critical portions of a system pose unique issues in maintenance. Safety-critical parts of a system may have requirements associated with them that virtually require (or exclude) certain types of maintenance.

Human Factors

Along with the considerations about the economic aspects of maintenance is the very real possibility that a condition that requires maintenance can be exacerbated by improperly performed maintenance, or human involvement. No matter what decisions are made about how and by whom maintenance is performed, human error needs to be carefully considered as a potential problem source.

Diagnostics

Built-in system diagnostics can be an invaluable troubleshooting aid when performing maintenance. Their use needs to be weighed against a variety of factors. Economics play a large role again. If the system will never be repaired, but only replaced, built-in diagnostics are useless except for indicating system failure, and for testing during development. Even there, their use is questionable given the cost of incorporating them in the design in the first place. If built-in diagnostics are available for troubleshooting, the question of how much information will be made available about their function arises. Perhaps it is economically advantageous to patent the diagnostic interface to the system and license or charge third-party service centers to use the diagnostic tools.

Major hazards

Major hazards could arise from the following:

- The lack of control of spares such that incorrect materials or items outside specification (e.g. non-flameproof equipment) are used in replacement of plant items leading to increased risk of loss of containment, fire or explosion.
- Failure to drain and/or isolate pipeline to dismantling causing release of flammable or toxic substances.
- Maintenance being performed incompetently (particularly alarm/action set points on instruments incorrectly set, alignment of couplings on pumps, motors running in wrong direction, safety features left disconnected/ dismantled, gaskets left out, bolts torqued incorrectly or bolts missing, non-return valves orientation incorrect, pipework/flexibles incorrectly connected/installed, pipeline spades/orifice plates left in/removed, relief valve springs over tightened, bursting discs orientation incorrect/left out).
- Scheduled maintenance not being undertaken as required or breakdown maintenance inadequate, leading to unrevealed failures of safety critical items.
- Lack of knowledge by maintenance staff of the working environment where maintenance is being carried out (i.e. lack of risk assessments, warning signs, method statements, emergency procedures), leading to ignition of flammable substances (e.g. heat sources such as cigarettes or welding, static and electrical discharge, use of non spark-resistant tools) or injury/fatality from incorrect personal protective equipment (e.g. respirators) being worn.
- Unauthorized staff performing maintenance functions.

CHAPTER -2

MAINTENANCE -- GUIDING PRINCIPLES

"The combination of all technical and administrative actions , including supervision actions , intended to retain an item in, or restore it to , a state in which it can perform a required function"

This definition has a number of components:

- *"Item":* this term include all hardware and associated software such as equipment, components, devices, systems etc or what is also called physical assets.
- *"Performed a required function" :* maintenance is concern with insuring that equipment can perform the functions that are required of it . these functions are a combination of design, which defines the limit of use and of its actual operation , which describes its actual use .
- *"to retain an item in , or to store it , to a state"* : the purpose of maintenance is either to perform an action that will keep equipment performing as required by doing preventive maintenance (to retain) , or to restore it when it has failed by doing corrective ,maintenance .
- *"combination of all technical and administrative actions , including supervision actions" :* maintenance is not only the execution of maintenance task but also administrative action , such as planning and scheduling , and supervisory action such as hiring and training skilled personnel .

2.1 TYPES OF MAINTENANCE

Maintenance operations have been categorized based on their frequency and their motivating factors. Four of the most common types given below are as follows- predictive, preventative, corrective and fault-finding.

(a) Predictive maintenance involves a series of steps prior to actually performing maintenance. It begins with sampling physical data over time, such as vibration or particulate matter in oil. Analysis is then performed on the collected data to create an appropriate maintenance schedule, and maintenance is performed according to the schedule. This type of maintenance analysis works well for mechanical systems because the failure modes are well understood. Additionally there is historical data useful for creating and validating performance and maintenance models for mechanical systems.

(b) Preventative maintenance refers to maintenance performed when a system is functioning properly to prevent a later failure. Generally, it is performed on a regular basis and the maintenance will be performed regardless of whether functionality or performance is degraded. The frequency of the maintenance is generally constant, and is usually based on the expected life of the components being maintained, but there is not necessarily any monitoring occurring at the same time (as there would be in predictive maintenance).

(c) Corrective maintenance refers to maintenance done to correct a problem when something has failed, or is failing. The need for corrective maintenance can be beneficial or detrimental depending on the product and the profit model used during the design phase of the product. On the most obvious level, corrective maintenance is detrimental to operation because it means that something failed, and the system is (probably) not available during the time needed to perform the maintenance. On the other hand, it may be that the economics and planned functionality of a system are such that using a cheaper, replaceable device for which failure is anticipated, makes sense.

(d) Failure-finding maintenance involves checking a (quiescent) part of a system to see if it is still working. This is most often performed on portions of a system dedicated to safety -- protective devices. This is an important type of maintenance check to perform because failures in safety systems can have more catastrophic effects, if other parts of the system fail.

2.2 TECHNICAL STANDARDS AND SAFETY ACT FOR OIL AND GAS PIPELINE SYSTEMS

(a) Activation of pipeline

(1) No person shall activate a pipeline unless the pipeline is licensed and a certificate holder for the purpose has ensured that the pipeline meets the requirements of this Regulation.

(2) A transmitter or distributor shall ensure that a pipeline is not activated unless the requirements of regulation have been met.

(b) Use of oil and gas pipelines

(1) Before using an oil pipeline, an operating company shall, except with respect to routine maintenance, obtain a declaration from a professional engineer declaring that the design, construction, installation, replacement, extension, reclassification and testing of the pipeline have been carried out in accordance with the Regulation.

(2) An operating company that has a gas pipeline having a diameter in excess of 219.1 millimeters or that is intended to operate at a pressure in excess of 860 kPa, that is constructed, installed, replaced, extended or upgraded, shall obtain a declaration from a professional engineer declaring that the design of and the construction specifications for the pipeline are in accordance with the Regulation.

(3) Subsection (2) does not apply to a service line, as defined in the code adoption document, with a diameter of less than 88.9 millimeters.

(4) Before using a gas pipeline, an operating company that has a gas pipeline installed or tested shall obtain a declaration from a person who is certified for that purpose under Fuel Industry Certificates declaring that the installation or testing was carried out in accordance with the Regulation.

(5) Before activating a pipeline that has been upgraded, an operating company shall obtain a declaration from a professional engineer declaring that the pipeline has been upgraded.

(6) An operating company shall file the declaration referred to in subsection (5) with the director, where the upgrading results in an operating stress level greater than 30 per cent of the specified minimum yield strength of the pipeline.

(7) The operating company shall retain the declarations obtained under subsections (1) to (5) for the life of the pipeline and shall make the records readily available upon request of the director.

(c) Unsafe condition

Where the director has reason to believe that an unsafe condition exists in a pipeline, an operating company shall uncover any part of the pipeline at the written request of the director.

(d) Application for license

(1) An application for the following licenses or their renewal shall be made to the director in the form published by the designated administrative authority and shall be accompanied by the fee set by the authority:

1. A license to transmit gas.

2. A license to distribute gas.

3. A license to transmit oil.

(2) An operating company need not be licensed if its oil transmission pipeline system is less than 20 kilometers in length.

(3) A license or a renewal expires 12 months after it is issued.

(4) A license or a renewal shall state the date on which it is issued and the date on which it expires.

(5) An inspector may inspect the installations and repairs performed by or on behalf of an applicant for or holder of a license referred to in subsection (1) and the workmanship relating to those installations and repairs, to determine whether they comply with the Regulation.

(6) No license or renewal shall be issued until the applicant for or holder of the license has paid the fee set by the designated administrative authority for an inspection under subsection (5).

(e) Lost or destroyed license, etc.

(1) A person whose license is lost or destroyed shall apply for a duplicate or, where the name of the license holder has changed, shall apply for a new license.

(2) The director shall issue a duplicate license or, where the name of the license holder has changed, a new license, on receiving an application therefore and upon payment of the fee set by the designated administrative authority.

(3) The holder of a license whose address has changed shall notify the director of the new address within 30 days of the change.

CHAPTER – 3
PIPELINE MAINTENANCE

The huge investment in pipe, pumps, compressors, drivers, control systems, the other equipments and cost of down time make maintenance of pipeline system critically important. Various maintenance jobs involved are described below:

3.1 RIGHT-OF WAY

The pipeline right-of-way (ROW) is the area along the pipeline that has been legally permitted to be used by the pipeline company to construct, operate, and maintain the pipeline. The ROW runs the entire length of the line and is wide enough to allow for construction equipment and cathodic Protection equipment installed on the line and, in some cases, for access roads. Most ROWs vary greatly and can be from 10 to 100 feet wide. After the pipeline is built the ROW is returned to its original condition restoring fences across it, so that the use of the adjoining land is not obstructed. How often a right-of-way is inspected is determined by by several factors, including the size of the line, the class location of the line, the terrain where the line is installed, and the weather conditions since the last inspection. All of these factors are taken into account when determining how often a right-of-way should be inspected.

(a) Navigable water crossing inspection

All these water crossings should be inspected at least every five year. It is done to ensure the integrity of the pipeline and to determine the impact of the flooding, upstream construction, or other activities. It tells about the change in horizontal alignment of the pipe, the river bottom profile, verifying that the pipe has an adequate cover. Navigable waterways are defined as those subjected to commercial barge traffic. It includes –

- Pipeline location-- Pipeline can be located by the use of the existing drawing and probing/sonar equipment.

- Surface inspection -- Inspection of adjacent banks and ROW.
- Submarine inspection—A diver passes over each pipe at interval of 20 feet or less and diver follows the pipe section with continuous passes. The size and build up of debris against exposed or suspended pipe section, the condition of pipe and its coating the nature of river bottom at the pipe and any other under water condition that may appear to adversely affect the safety of pipeline crossing are also determined and reported. An under sea inspection device submersible can also be used for deeper and longer period.

(b) Methods of patrol

The pipeline ROW is patrolled by plane, by vehicle, or on foot. The frequency of aerial, vehicle, and foot patrols for liquid lines must satisfy the requirement of the pipeline regulations. The sum of all vehicle, foot, and aeria1 patrols must be at least 26 times per year and at least every 3 weeks for each pipeline ROW. Some conditions, such as floods, significant increases in third-party construction or agricultural activities, or evidence or threats of vandalism may warrant scheduling more frequent inspections. Some inspections occur more often according to the product and population density.

Types of patrolling

- **Aerial Patrol**—The most common form of information gathering is done by aerial patrol on a weekly or biweekly schedule according to DOT and company policy. During these patrols, we watch for and report developments or changes on and adjacent to the ROW that may result in need for maintenance or investigation. Soil erosion, stream bed changes, weathering of markers and signs, and growth of bushes and trees are gradual changes that will eventually require maintenance. Construction work near the ROW is noted and reported Because of the variety of geographic and physical circumstances, details of speed, altitude, weather, time of day, direction of flights, flight schedules, and other factors must be determined by the inspector .Photographs of observations arc encouraged where practical and should be used to document any leak or discharge, damage to the pipeline or ROW, or any special situations. The types of equipment normally required for aerial patrols include relevant pipeline maps, cell phone, a pager, and a camera.

- **Vehicle/Foot Patrol**-- A person who may walk or use a vehicle to inspect the line is called Linewalker. Although Aerial Patrolling has taken over much of line inspection, linewalkers are still needed in certain areas, such as densely populated areas where flying, at low altitude may not be allowed vehicle/foot patrol duties-include observing the ROW conditions, construction activity at or near the line, encroachment, line marker conditions, soil erosion, uncovered pipe, pipeline facility condition, leaks, and any other condition that would place the pipeline or public in danger. Vehicle and foot patrols are a good way to check the conditions clos1y. Reliable and useful information about specific situations is often obtained from on-site surveys by experienced maintenance crews. They observe conditions and make notes of conditions on every trip to or along the pipeline ROW.

(c) Reportable observations

The inspector checks the surface conditions on or adjacent to each pipeline ROW and reports appropriate observations. In cases other than emergencies, the report is written from the inspector's log. The notable conditions to be reported on petrol may include--

- **Emergency situations/evidence of release**—The definition of an emergency situation is a leak, evidence of a possible leak or activities that pose an immediate threat to the pipeline or to public safety. A possible leak observation might be petroleum on the ground, vapors in the air, wilted or dead vegetation over the pipeline, dead or sick animals near the pipeline, the smell of hydrocarbon, or petroleum sheen on water.
- **Environmental changes**—River bank erosion, excessive vegetation along the right of way, earth moment, trees or debris clogging waterways etc.

- **Damaged or exposed pipeline---** Pipeline damage may be discovered directly on aboveground pipe. Evidence of a leak is indicative of damaged underground pipe. Pipeline exposure may be caused by environmental conditions, such as weather or earth movements. Exposed pipe should be reported for inspection and reburial. Whenever exposed pipe is discovered, it must be inspected for evidence of external damage, corrosion, and the extent of the damage or corrosion.
- **Missing or damaged signs/marks**—sings and marks are required at all aboveground pipelines facilities, at all roads rail, and water crossings and at sufficient interval along the ROW to identify the pipeline location. The information on the sings or markers must be up to date and correct. Sings may become damaged by weather or other natural conditions, or they may be vandalized or stolen. During inspection patrols, any damaged, missing, improperly located or inaccurate sing must be reported and replaced according to company policy.
- **Encroachment**—the original activities along the pipeline are taken into account when starting pipeline operation and most of the ROW is restored to its original usage after pipeline construction. Unauthorized activities on the pipeline Row that may affect the pipeline are often spotted by patrols during line inspection and are reported to management. The unauthorized encroaching party is advised to cease activity until consent can e given by the company. The companies then investigate the activity and communicate with the encroaching party about the final resolution. If an immediate danger is posed by such activities, they must be stopped, and an emergency call must be made to the control center.
- **Vandalism**—evidence of activity around a block wall or any other place along the pipeline ROW might indicate a line tap, vandalism, or sabotage. All surface facilities, such as pump station and breakout tanks, should be provided with protection against vandalism or unauthorized entry. Fencing may be present and should be checked by patrols for damage.

3.2 IN-LINE INSPECTION

The purpose of an in-line inspection is to identify deposits, the presence and extent of corrosion, pipe deformation, and other anomalies. In-line inspection is one method used to assess the integrity of a pipeline. The first in-line inspection tools were designed to detect corrosion and pipe deformation. Inspection devices, propelled through pipe in the same way as scrapers, measure and record pipe metal thickness and indicate the effects of both internal and external corrosion. These devices are commonly called smart pigs, and the in-line inspection process is referred to as smart pigging. Tools other than pigs are available to address specific problems. In-1ine-inspection may involve running several tools through the line, one after the other. Different in-line inspection technologies exist for locating and identifying pipeline anomalies. The accuracy and reliability of each inspection tool will vary with the type of tool, the overall condition of the pipeline and other factors.

Types of pigs

Pigs are designed to travel through the pipeline, pushed by the pressure of the flowing product in the line. Generally, pipeline pigging tools fall into two categories: cleaning tools and measurement tools. Typically, cleaning pigs are simple arrangements of brushes, scrapers, and cones. In contrast, pigs using in-line-inspection technology, or smart pigs, are equipped with sensors and flexible arms connected to data recorders that record changing internal measurements and use battery power to operate these systems. Some have on-board transmitters that allow the operator to use a global positioning system (GPS) to track the progress of the pig as it proceeds along with the line.

- Cleaning tools
- Sizing tools
- Metal loss tools
- Crack detection tools

(a) Cleaning Tools

Buildup of contaminants and deposits in the pipeline can impair flow efficiency by impeding product flow. These deposits, if not detected and removed from the inner pipe surface, can lead to corrosion and eventual line failure. Cleaning pigs are used to remove accumulated solids and debris from the walls of the pipeline before they have a chance to cause severe damage to the system. Paraffin most often accumulates in crude oil pipelines; in gas pipelines, a substance formed by the solvents used with corrosion inhibitors must be removed. Cleaning pigs are also used to scour corrosion deposits and to remove water, corrosion products, microbes, and food for microbes. Cleaning pigs come in a variety of shapes, sized surface configurations to combat a number of pipeline conditions. Cleaning pig types include:

- Foam pigs
- Brush-equipped pigs
- Gel pigs
- Scraper disc and cone-equipped pigs

(b) Sizing Tools

Sizing tools are those inspection tools that help the operator determine if there have been any changes in the pipeline geometry. While performing the same basic function, each of the various types of sizing tool provides information of a somewhat different nature and at a different level of detail. Sizing tools include caliper tools, pipe deformation tools, geometry tool and gauging tools.

(c) Metal-Loss Tools

Metal-loss tools are designed to detect corrosion caused metal loss from the pipe. The two types of metal-loss tools used in the pipeline industry are:

- Magnaflux Tools
- Ultrasonic Tools

(d) Crack-Detection Tools

In-line crack-detection tools have recently been developed to detect longitudinal cracks and crack-like features, such as stress corrosion cracks, long seam cracks, weld failures, and narrow axial external corrosion. These tools use either ultrasonic shear waves or circumferential (transverse) magnetic flux technology.

- Shear Wave Tools
- Magnetic Flux Tools

Selecting the Pig

The type of pig selected and the specific configuration for the pig are determined from a number of criteria, including:

- **Purpose**
  - Type, location, and volume of substances to be removed
  - Type of information to be gathered

- **Line contents**
  - Contents of the line during the pig run
  - Available drive pressure
  - Velocity of the pig
- **Characteristics of the pipeline**
  - Minimum and maximum internal line diameters
  - Absence of reduced port valves in the line
  - Check valves that allow the pig to pass
  - The bend radii of the pipe matching the pig
  - Known physical restrictions, such as dents that have been repaired
  - Other features such as valve types, branch connections, and the Elevation profile

Pipeline characteristics can be determined by running caliper tools (pigs), deformation pigs, or pigs with sizing plates. Pigs are typically chosen to negotiate a 1.5 diameter (D) bend or a 3 D bend. This is also somewhat dependent on the wall thickness of the pipe to be inspected. A pig that will pass a 1.5 D bend in standard wall pipe may not negotiate that same bend radius in heavier pipe. Pig launchers and receivers must be able to accommodate the type of pig being run.

Pipeline cleaning

During the pipeline cleaning runs a number of common solvents have been added and run in conjunction with the pigs to aid in the cleaning of these lines. These products help in certain aspects of the cleaning runs that they dissolve some of the materials that were trying to be removed from the interior surface of the pipe wall. With special fluids that are designed to breakdown, suspend solids, and reduce surface tension, the cleaning programs can be enhanced. Every day there is a considerable amount of time and money spent on making mechanical pigging runs in Pipelines, typically they are run for more than one reason:

- Cleaning the internal pipe wall surface
- Removing free solids and debris
- Gathering data about the integrity
- Applying some sort of chemistry to the inside surface of the pipeline.

By adding special fluids to this process, the effectiveness of these runs can be enhanced:

- Improving flow conditions
- Reducing differential pressures
- Removing more solids per run (more solids than 50 pig runs would achieve)
- Reducing the risk of pigs getting stuck;
- Optimizing chemical inhibition programs.

The flow efficiency of a pipeline is based on the internal diameter of the pipeline and the friction that the pipe wall surface applies to the product moving it through it. By pigging the pipeline routinely, the internal diameter of the pipeline can be maintained. A fluid to break down the contaminant and carry it out of the line is required. Also the presence of a contaminant on the pipe wall can create a reduction in efficiency even though the ID of the pipe has not been substantially reduced. The surface roughness of these materials can tend to apply friction to the product being transported through the pipeline and create a backpressure.

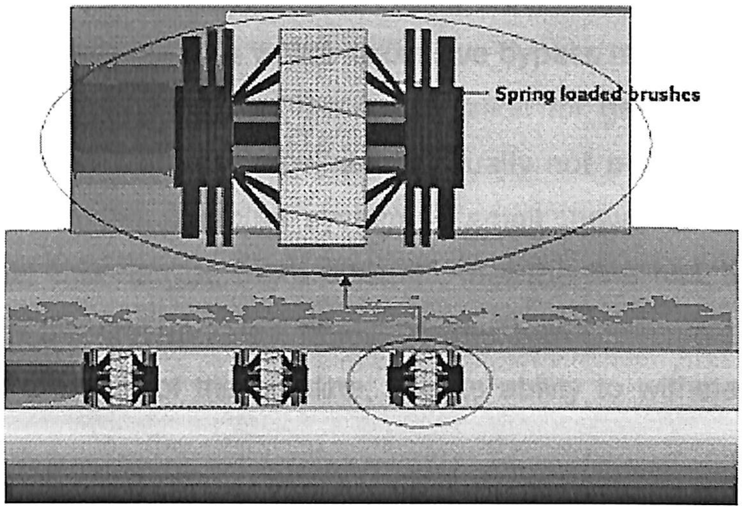

Fig.1--Cleaning and filling a new pipeline

They typically will be composed of a combination of a wiping/sealing surfaces made up of discs, cups or foam with brushes mounted on them made out various materials. Some pig designs will have controlled by-pass to try and keep some solids in suspension. By adding pipeline-cleaning compounds that have been specially formulated to address each of these issues, the physical limitations of the design of cleaning pigs can be overcome. As an added benefit these solutions can actually reduce the amount of friction on the pig allowing the pigs to have a longer effective life.

<u>Pigs and pigging in pipeline flooding/filling</u>

For hydrotesting a new line, the quality of the filling operation is of major importance. The specification for fill water is that less than 0.2% of the pipeline volume can be air after the filling operation is complete. The reason for this is that the compressibility of the air has a significant effect on the hydrotest operation, and can give error in result. For this reason, it is not generally possible to control flooding using only a single pig. It is usual to specify pigs that have good sealing characteristics, and to have two or more pigs in the train. This train will usually be designed in a relatively conservative way, since the costs of having to repeat the exercise may be significant.

Speed is an important consideration when filling a pipeline. Speeds that are too low or too high can lead to situations where excessive bypass may occur, compromising the ability of the pig train to meet the specification for gas content after filling is complete. Filling small diameter pipelines is usually not a problem as the volume output required from the pumping system is small; however when filling larger diameter pipelines this can be more difficult. After the line has been successfully flooded, the line is brought up to test pressure, to--

- Verify the strength of the pipeline, and its ability to withstand the operating pressure
- Verify that there are no significant leaks
- Find defects in equipment
- Relieve some of the stresses potentially induced during construction.

Pigs and pigging in pipeline dewatering

After the hydrotest is complete, the line may be left full of the (treated) test water for some time. At some stage prior to use however the pipe will need to have all of the water in it removed. For oil pipelines this is a straightforward process, generally performed as the final commissioning stage, i.e. production through the pipeline is used to force the water out of the line. For most oil pipelines the addition of small quantities of water to the first production is not likely to cause any significant problems. In this case more often than not, a single pig will be used as the interface between the water and the oil.

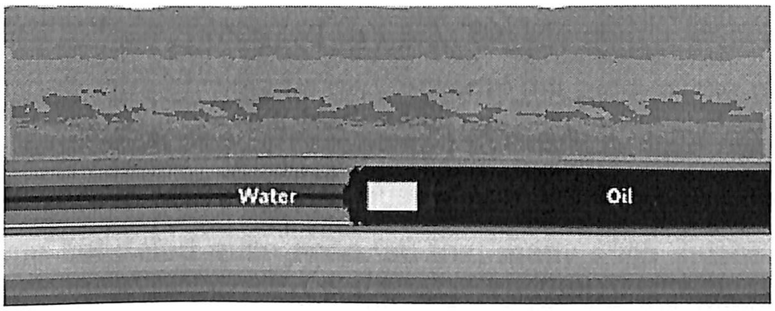

Fig.2 Dewatering of oil pipeline

For gas and process pipelines the situation is much more complicated. The presence of residual water in lines can have very serious consequences, as it can cause corrosion to occur, and as for the possibility that hydrates may form if water is present as the line is brought up to pressure. For this reason, the pig train used to dewater a line will usually consist of a number of elements, each with a specific aim. First will be a train of pigs designed to sweep as much water as possible out of the line.

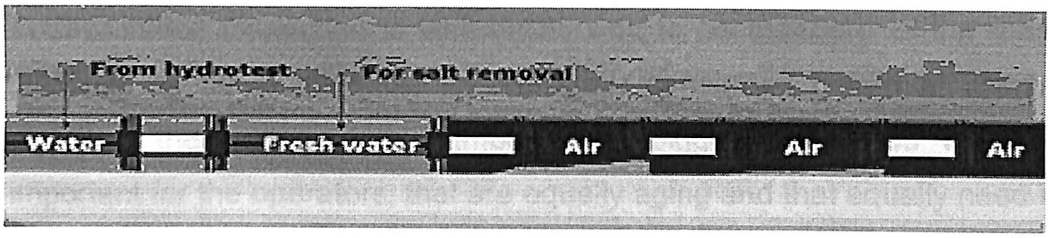

Fig. 3 Dewatering a gas pipeline

This train consists of a number of bi-directional pigs intended to sweep the bulk of the liquid out of the line. In cases where the water used to fill the line was sea-water, a slug of fresh water might be introduced into the line between the first two pigs in order to remove salt from the line. Again in this case, production pressure is not available to move the pig train and significant compression must be available in order to propel the pig train.

A number of techniques are used to reduce residual volume to an acceptable value. They include air drying and vacuum drying. Pigs have a role to play in air-drying as, very often; a series of foam swabs will be run in the line during air-drying operations. The first pigs pushed through may be bi-directional but most of the operation will be performed using bare foam pigs. These have a dual action: they swab water off the pipe wall by absorbing it; and they also push the water out in front of the pig. Bare foam pigs become saturated quite soon, so that many such swabs will usually be run. This will continue until it appears that the swabs are not effectively removing any remaining water, when a final stage of drying by purging the line with dry air or nitrogen will proceed without pigs.

An alternative to this in the final phase of drying is in running pig trains to batch hydrophilic chemicals through the line. The aim is to bring any moisture not removed from the line by pigs in contact with chemicals that will absorb water. Chemicals that are used for this purpose include methanol and glycol. Typically, slugs of methanol are placed in perhaps two batches in a train of four or five pigs, driven by nitrogen and with nitrogen between them .

Unpiggable pipelines

Today, in-line inspection is well on its way to be standard in the maintenance of pipelines as far as piggable pipelines are concerned. However, next to piggable pipelines there is a large number of un-piggable pipelines which are equally important for the operators, that are equally aging and that equally need inspection.

(a) What is an un-piggable pipeline?

A piggable pipeline is a pipeline that is designed to allow a standard inspection tool to negotiate it, which requires basically a more or less constant bore, sufficiently long radius bends and traps to launch and receive the pigs. This way, an un-piggable pipeline can be defined as not designed like this.

There are plenty individual reasons, why a pipeline can not be negotiated by standard inspection tools.

- Over- or under-sized valves,
- Repair sections in a different size,
- Short radius or mitered bends can make it impossible for standard inspection tools.

Within the pipeline industry the pipeline networks consist mainly of piggable pipelines and may be subject to regular in-line inspection. However, usually these networks have a certain percentage of un-piggable kilometers.

(b) Is there any way to achieve the benefits of in-line inspection on un-piggable pipelines as well?

First, there is the option to modify the pipeline in a way that it becomes piggable in the end. This option, however, is in most cases not easy. Modifications usually require to interrupt operation and replacement of the un-piggable elements and is, therefore, expensive or even impossible.

Second, the inspection equipment can be tailored to the existing conditions in order to overcome the situation that is considered un-piggable for standard inspection tools.

Third, it may be practical to modify both the pipeline and the in-line inspection tool. Under any circumstances it is necessary that the pipeline operator and the in-line inspection vendor analyses together such things like technical feasibility, cost and risk factors, schedules, alternative scenarios etc. Only at the end of these considerations there will be a plan that shows whether and to what degree the pipeline, the inspection equipment or both will have to be modified. Whether a cost-effective solution can finally be developed depends much on the flexibility and versatility of the in-line inspection technology available. The better an inspection tool can be tailored to the individual obstacles of the pipeline, the smaller will be the need to work on the pipeline. In the ideal case, a special tool will be engineered to the requirements of the pipeline and the pipeline will stay as it is.

3.3 PIPELINE DAMAGE INSPECTION

Monitoring pipeline integrity is generally defined as the process of keeping the pipeline system in satisfactory working order and keeping pipeline failures to a minimum. Minimizing system failures directly impacts the life cycle or the useful life of a pipeline system. Most pipeline companies have emergency reaction plans in place designed to allow them to respond to incidents and disasters in a timely and organized manner. These emergency plans are separate from the company's pipeline integrity plan that covers inspecting and servicing equipment and facilities and replacing worn items where needed. During the construction phase, protective coatings and, in some applications, casings are put into place as a first line of defense against damage to the pipe.

Types and sources of damage

Statistics show that several forces contribute to pipeline failures. Recognition of the type and source of damage may prevent the damage from recurring or becoming more serious.

(a) Construction Damage

Physical damage to pipelines is an ongoing danger, and pipeliners work hard to protect their assets. Construction machinery, when misused or employed without first completing all necessary notification requirements, can quickly cause great damage to a pipeline. Pipeline companies require that encroachment for construction on or near their ROW proceed in a very specific way so that the pipeline, people, and environment are protected.

One-Call Systems

Companies and individuals must strictly observe applicable safety guidelines when performing work directly above or near underground pipelines. One-Call notification systems are damage prevention programs for the use of contractors and others who perform any construction or excavation activities. Some of these activities include digging, blasting, boring, trenching, tunneling, backfilling, removing aboveground structures by explosive or mechanical means, and other earthmoving operations.

Persons or companies planning to engage in any of these activities are required to call the One-Call notification system number listed on a One-Call system marker and report their intent to perform excavation activities.

Locating Underground Piping

When work is to be performed above or near the underground pipe, the owner of the pipeline must locate and mark the pipeline and ROW so that they are plainly discernable to the persons planning construction or excavation work.

- Install temporary markers
- Confirm the depth of the cover.
- Use physical and electronic locating equipment (battery-powered locator often referred to as a stick locator).

The selection of tools and methods is made to fit the conditions at the locating site. In some cases, the soil must be removed in, to order to locate the pipe. Power equipment, such as backhoes and excavators, are not normally used until the exact location of the system is established because of the potential damage they can cause. Instead, a water-vac unit is used to remove soil from above a pipeline.

Using Heavy Equipment

Backhoes, dozers, and similar construction equipment are large, powerful vehicles that, if used properly, can safely and quickly expose under ground pipe by moving large amounts of cover from the pipeline.

(b) Potential Operations Damage

A number of widely recognized critical operating situations are inherent in the gathering, processing, storage, and distribution of petroleum products. Correct handling of these situations as they arise will prevent or minimize damage to the pipeline system and equipment and injury to personnel. Damage during the operation of the pipeline can be caused by:

- Mechanical or electrical failure
- System error

- Communication

- Programming
- Design specification versus current actual state

- Human error

These errors or failures can result in:

- Movement of the piping and its components
- Seal leaks
- High sump levels (overflow)
- Rupture disk failures
- Bulges in tanks Releases

(c) Third-Party Damage

Pipeline accidents are often a result of third-party damage caused by persons who have entered the ROW and initiated work without permission from the ROW owner. Third-party damage is often defined as any damage, whether intentional or inadvertent, to a pipeline system or to the ROW by someone other than the pipeline owner or an authorized contractor. This type of damage is regarded by most pipeliners as the primary cause *of* pipeline accidents and safety incidents.

To guard against the damage caused by third parties that encroaches on a ROW without notifying the appropriate authority, most companies have developed programs that include aerial, vehicle, and walking patrol inspections by trained and experienced employees.

Company Requirements

Pipeline companies holding ROW agreements with landowners are responsible for pipeline safety within the boundaries of the ROW. When other companies wish to work above the pipeline or on the ROW, they must secure the permission of the company holding the ROW agreement. In order to obtain this permission, the third party must agree to the requirements and policies of the company holding the original agreement.

Measuring Pipe Clearance

The Department of Transportation (DOT) requires a minimum of 12" between pipelines and any other underground structure except drain tiles. Individual companies may require more. One must determine clearance to ensure that separation between company assets and foreign assets is adequate to prevent electrical interference and physical contact between the two.

(d) Damage from Acts of Nature

Pipeline conditions must be checked following hurricanes, floods, earthquakes, tornadoes, lightning, mud slides, land slides, storms, and other acts of nature that have the potential for causing damage to the system. Many natural events can cause movement of the pipeline, which can result in cracking, leaks, or ruptures of the piping and its components.

(e) Blasting Damage

Each company has its own rules covering the proximity of blasting. Following any blasting close enough to have caused damage to the pipeline, a leak survey and a post-blast survey must be performed. The leak survey may involve atmospheric or visual monitoring or gas, detection equipment. The post-blast survey is a visual check of the pipeline ROW that covers the area that could have been affected by a blasting operation. Pipe segments upstream and downstream of the blast area must also be surveyed. Types of blasting include:

- Seismic
- Mining
- Road construction

The use of small directional charges helps to limit the impact to the pipeline, but after any blasting has taken place, pipeline maintenance personnel must perform a post-blast survey using the written and approved procedures published by their company. Post-blast surveys include performing leak surveys and monitoring for pressure loss.

Performing Leak Surveys

Leak surveys may employ a number of inspection methods, such as visual or atmospheric monitoring, or they may use gas detection equipment that can be used at ground level above the pipeline.

Monitoring for Pressure Loss

Pipeline maintenance personnel must monitor instruments for any indication of a pressure loss during or after blasting near the pipeline.

(f) Inspection following movement

Visually inspect the entire length of exposed pipeline to ensure that there are no wrinkles, gouges, or other apparent physical damage. Pay special attention to the newly induced longitudinally stressed areas at-the end of each section that moved. If damage is noted, assess the damage and follow appropriate company procedures. If no damage is encountered, visually inspect the entire length of exposed pipeline to ensure that the coating was not damaged during the move. If the coating is damaged, take the necessary steps to repair the coating. If no coating damage is encountered, inspect the ditch and backfill spoil to ensure that no materials capable of damaging the coating are present.

3.4 PIPELINE REPAIR

The need for pipeline repair can arise from emergency, routine pipeline maintenance, or pipeline modifications. When repairs are made in an emergency, the primary goal is to end the emergency and minimize damage pipeline repair may require that the pipeline be shut down, or a temporary bypass system may be used. Special fittings and machines can be used to temporarily bypass a section of pipeline without interrupting service .This may require cutting and welding on a pipeline operating at reduced pressure but still containing product.

Any weld made on an in-service pipeline is known as a hot tie-in. Pipeline repair techniques include:

- Repair standards Pipe sleeve installation
- Cutting out and replacing pipe Tapping
- Casing repair
- Weld repair
- Support structure installation and repair

(a) Repair standards

- Planning for limiting pipeline pressure during repairs.
- Planning for excavation activities, including pipeline locating and marking, One-Call notification, and provisions for pipeline and excavation support and excavating procedures.
- Arranging for qualified persons to evaluate the coating, pipe integrity, and corrosion when the pipe is exposed.

(b) Installing pipe sleeves

Pipeline defects are categorized by type and severity. Repair equipment and sleeving techniques are available to repair almost every type of defect. However, if physical or environmental conditions make sleeving impractical, the pipe may need to be replaced. Repair methods are determined by considering the defects to be repaired. This includes looking at the following factors:

- Size and shape of the defect

- Roundness of the pipe
- Presence of dents
- Presence of cracks
- Surface corrosion and interaction of corroded areas

Sleeves can be used for temporary and permanent repairs. In general, temporary repairs consist of mechanical leak clamps and bolt-on sleeves unless they are welded permanently in place. The use of sleeves for repairs is only possible when the damaged pipe is within the limits of pipeline deformity. Varieties of repair sleeves are available and are chosen to fit specific situations. Sleeves that may be used for repair include:

- Split sleeves Oversleeves
- Tight-fitting sleeves
- Clock spring reinforcement sleeves
- Weld plus couplings

(c) Weld Plus Couplings

Weld Plus couplings are safety welding couplings that are used when a section of pipe needs to be repaired on the pipeline. They are a reliable method of joining pipe when service must be restored to the pipeline immediately or when a butt weld is difficult or impossible to achieve. The couplings are used to join and seal the connections on each end of the new pipe section to the existing pipeline. They are one-piece assemblies that include seals on each end.

(d) Replacing pipe

Many pipelines have been replaced in the last 10 years with the priority and timing of replacements based on the condition of the pipeline and its ability to deliver a required capacity. As hundreds of pipe leaks are repaired every year and the number of leaks is increasing, the perception was that the pipeline system was deteriorating and that it may be risky to defer the replacements.

Possible factors which may affect pipeline service lives:

- Age, materials and other relevant data on pipelines

• Failure history
• Failure modes
• Decay curves
• Current demands
• Cost of replacements of “like for like” pipelines (dimensions and flow rate)
• Generate an optimized replacement program including year and total annual costs based on the prioritized replacement list and business impacts.

Optimizing replacement program

The determination of the optimal time for pipeline replacement was based on:
• Repair costs & Replacement cost
• Service Targets

The repair costs for each pipeline and pipeline segment were determined by using the average cost of each leak repair based on the historical records of leak repair costs in the current estimates. It was estimated that 80% of leak repairs do not require shutdowns. Due to the poor performance and quality of pipes, and the fact that the pipe wears away once a leak initiates, it is assumed that 100% of pipe failures would require a shutdown for repair. Any existing break pressure structures would remove and higher class pipe used.

As the basis for the replacement program is predominantly driven by only replacing the shorter length, functional location sections of the pipelines, the cost of each of these sections is in many cases quite small. In comparison, the preliminary & detailed design costs, construction project management and mobilization etc. is very high as a percentage for these small sections. In addition to this, the entire pipeline will be required to be redesigned in some instances. Taking these factors into consideration and adding in the cost of design and construction project management, the revised program of pipeline replacements is finalized. This revised program had the financial affect of significantly reducing the annuities for pipeline replacement in the foreseeable future. Shutdowns required to repair leaks to pipelines are generally unplanned shutdowns.

(e) Repairing Casing

Pipelines are commonly routed under roads and railways through metallic sleeves or casings. The metal casing must be isolated from the steel of the pipe in order to avoid interfering with cathodic protection and creating an environment for corrosion. To achieve isolation, the pipe is provided with circumferential, non-conductive spacers. Spacers, also called isolators, are electrical non-conductive devices used to separate a metallic pipeline from another metallic structure. Concrete-coated steel pipe may also be used as an isolator. When the pipe is inserted into the casing, the spacers hold the pipe and casing apart. A spacer is placed close to the ends of the casing to prevent contact caused by movement from soil settlement or other conditions. The ends of the casing are sealed around the pipe to prevent moisture or debris from entering the space between casing and pipe and providing contact. In some cases, the casing will be filled with a non-conductive fluid. This is usually done when a short cannot be corrected through normal repairs.

(f) Support Structures for above ground Pipe

When underground crossings are not practical, overhead crossings may be constructed. With overhead crossings, you must consider problems involving strength and flexibility of pipe and supporting structures not ordinarily encountered in pipeline construction. Strength requirements are variable because of wind and ice loads. Flexibility must be provided to accommodate dimensional changes in pipe and structures from temperature and load variations. Vibrations that cannot be completely eliminated provide other stresses on the pipeline. Maintenance of these crossings requires monitoring and reducing the effects of these stresses. A major part of this is the installation, replacement, and repair of support structures. Pipeline repairs are often necessary because of an emergency situation, which can be extremely hazardous and result in damage to the environment. If potential repairs are identified and performed ahead of time, these hazards and damage can be minimized. Repair procedures which may be needed include installing sleeves, clock springs or other composite repair, tap installation, and cutting out and replacing pipe.

3.5 PIPELINE LEAKAGE SURVEY

A leakage survey is performed by means of a visual inspection or by use of leak detection instruments that detect the presence of natural gas, propane, or other gases. If a leak does exist the inspector must be alert to an unexpected gas release or the possibility of fire or explosion. It is also necessary to understand the characteristics of the gas in the pipeline. An important characteristic is the explosive limits, or the range that will support combustion of a flammable gas. Each gas has its own range, typically 5% to 15% gas in air.

(a) Conducting a Vegetation Survey

Vegetation surveys are performed as a part of routine ROW inspections and as part of the job whenever maintenance personnel are working on the pipeline route. Vegetation and other surface conditions will be affected by the escape of gas or other hydrocarbon into the soil surrounding the pipeline.

(b) Surveying with a Combustible Gas Detector

A combustible gas detector is an instrument that is capable of detecting hydrocarbons at very slight concentrations. This instrument pulls a volume of the atmosphere being sampled through it to analyze for the presence of hydrocarbons.

(c) Surveying with a Flame Ionization Gas Detector

A flame ionization gas detector is capable of detecting leaking natural gas or other flammable gases. The survey may be performed by walking the pipeline route with the unit or by driving over the route with the unit mounted on the vehicle. This instrument is more sensitive than any other detector and may read down to one part per million.

Modern pipeline maintenance focuses on the prevention of damage and deterioration so that emergency leaks and repairs can be reduced.

3.6 PIPELINE INSPECTION AND NONDESTRUCTIVE TESTING

NDE testing activities used to find out the integrity of pipe welds. Weld joints are visually inspected before the welding is started, as welding proceeds, and after the welding is completed to ensure that a quality weld is produced and that all code requirements are satisfied. If at any point a weld fails to pass inspection, it must be repaired or redone to the satisfaction of the inspection criteria. It is important to be able to visually inspect all pipe or components that are to be installed in the pipeline system to ensure that they are not damaged.

(a) Inspect Root Passes

Each root pass of a weld must be thoroughly inspected to identify any defects. All defects in, the root pass must be repaired before welding is resumed because defects, especially cracks, in the root pass can crack out or propagate through entire finish weld.

The following explains how to inspect the completed weld. When inspecting a completed weld:

- Inspect the entire weld to ensure that it is free of slag and scale that could mask other defects.
- Inspect the entire weld to ensure that there are no cracks or inclusions.
- Ensure that the amount of porosity in the weld is within specified limits.
- Ensure that the tie-in of the weld metal to the base metal is smooth.
- Ensure that undercut if any is within specified limit and does not violate the minimum wall thickness of the base material.
- Heat affected zone should be inspected for any defect
- Inspect the all the welded area to ensure that it has no craters.

(b) Nondestructive examination and evaluation

Nondestructive examination (NDE) methods are used to test equipment and components without damaging them. Nondestructive examination consists of one or more types of tests that quantify defects or detect future failures. With NDE, it is possible to detect defects or changes that will lead to premature failure. The results can be used to find the real cause of the change or abnormality and correct the problem, not just the symptom.

- ***Liquid Penetrant Test***

This test is used to highlight the cracks and gaps which are not visible to naked eye in the surface of smooth or nonporous samples. The liquid penetrant seeps into surface cracks, porosity, delaminations, or shrinkage areas by capillary action. Liquid penetrant inspection involves wetting the surface of a test object so that the liquid flows over that surface to form a continuous and uniform coating and migrates into cracks and surface defects. The liquid is then washed off the surface, and a developer is placed on the surface. As the developer draws the penetrant out of the defects, it is stained by the penetrant and highlights the cracks-and surface irregularities to form a visual image of the flaw. This method is environmentally safe and can be conducted in any industry and pipeline ROW.

- ***Magnetic Particle Test***

When a magnetic field is generated in and around a part made of a ferromagnetic material, such as steel or iron alloys, and the lines of magnetic flux are intersected by a defect such as a crack, magnetic poles are generated on either side of the defect. Magnetic particle inspection works only for materials that can be magnetized, such as steel and nickel alloys. In a magnetic particle test, the sample is magnetized by an electrical current, and magnetic particles are applied over the surface. These particles can be applied either dry or in a liquid carrier, such as oil or water. The flaws on or just under the surface of the sample modify the magnetic field so that the particles outline the defect in a pattern and highlight the shape and location of the flaw. This method is very sensitive to minor surface cracks and flaws that are near the surface. The disadvantages are the limitation to magnetic samples and the inability to read deeper flaws in the sample.

- ***Ultrasonic Test***

Ultrasonic use high frequency sound waves to detect noise generated by plant equipment ultrasonic instruments thickness in materials or "listen" for turbulence in pipes to detect internal leaks and malfunction other ultrasonic test instruments send focused, amplified sound waves into solid materials and compare them with the return wave to find flaws such as corrosion ban welds or casting flaws bellow the surface. The frequency range for ultrasonic monitoring is from 20,000.Hz to 100 kilo Hz. The velocity depends on the medium not on the propertied of the wave form are like a bent reflected form surfaces refracted when they cross boundaries of a different surface and diffracted at edges or around obstacle .this beam when and diffracted at edges or around obstacles this beam when reflected back creates a signature that is interpreted as an image by ultrasonic monitor.

- ***Radiography***

Radiography is a non destructive examination method that uses a beam of radiation that penetrates the weldment. Radiation is very sensitive and can be used to inspect the density of almost any ferrous, nonferrous, organic or inorganic material. Some of the radiation energy is absorbed, and the intensity of the beam is reduced. The variation in the beam intensity is recorded on film. These variations are seen as differences in shading that are typical of the types and sizes of any discontinuities present. Radiography can detect both surface and sub surface discontinuities. Because of extremely powerful nature of gamma rays, much radiographic work is now done with iridium sources. The principle advantage of gamma ray inspection is the low cost and portability of the source. The radiography method is used to detect internal defects and to check for proper alignment of assembled parts. Radiation is also used extensively to examine welds, check wall thickness and examine the quality of casting and forging.

3.7 HYDROSTATIC TESTING

Although pressure testing is not done as a part of routine inspections, most pipeline owners check the integrity of their pipelines. The most common form of pressure testing is hydrostatic testing. Usually done during periods of slack demand, this type of test requires that the line be taken out of service and cut at specified intervals. In pressure testing, the internal pressure is increased to a level above the normal or maximum operating pressure (MOP) in a segment of the pipeline for a specified length of time. The pipeline segment is isolated from the pipeline. A liquid medium, usually water, is used to fill the line and provide the internal pressure. The pressure test is used to ensure that the piping will withstand operating pressures without leaking. If a leak is discovered during testing, the segment has failed the test and must be repaired and retested.

3.8 MITIGATION OF CORROSION

External corrosion was by far the leading cause of incidents in this study, representing 60% of the total. However, with the limited data sample, we were unable to isolate the cause. All buried metallic pipe must be properly coated and have a cathodic protection system designed to protect the pipe in its entirety.

Newly constructed metallic pipelines must be coated before installation and must have a cathodic protection system installed and placed in operation in its entirety within one year after construction of the pipeline. However, the operator must make tests no later than six months after installation to demonstrate that no corrosion control measures are necessary. If tests indicate that corrosion control is necessary, the pipeline must be cathodically protected. Cathodic protection requirements do not apply to electrically isolated, metal alloy fittings in plastic pipelines if the alloyage of the fitting provides corrosion control, and if corrosion pitting will not cause leakage. The operator must determine areas of active corrosion by (a) electrical survey, (b) where electrical survey is impractical, by the study of corrosion and leak history records, or (c) by leak detection surveys. Active corrosion means continuing corrosion, which, unless controlled, could result in a condition that is detrimental to public safety.

For master meter operators, all continuing corrosion occurring on metallic pipes (other than cast iron or ductile iron pipes) should be considered active and pipes should be cathodically protected, repaired, or replaced. For operators of small municipal gas systems, all continuing corrosion occurring on the distribution system in city limits (within 100 yards of a building intended for human occupancy, regulator stations, and at highway and railroad crossings) should be considered active and pipes should be cathodically protected, repaired, or replaced. Need to clarify what's needed.

(a) Monitoring

A piping system that is under cathodic protection must be systematically monitored. Tests for effectiveness of cathodic protection must be done at least once every year. Records of this monitoring must be maintained. Short, separately protected service lines or short, protected mains may be surveyed on a sampling basis. At least 10 percent of these short sections and services must be checked each year so that all short sections in the system are tested in a 10-year period. When using rectifiers to provide cathodic protection, each rectifier must be inspected six times every year. The intervals must not exceed 2½ months, to ensure that the rectifier(s) is properly operating. Records must be maintained. Operators must take prompt action to correct any deficiencies indicated by the monitoring.

(b) Electrical Isolation

Pipelines must be electrically isolated from other underground metallic structures (unless electrically interconnected and cathodically protected as a single unit).

(c) Test Points

Each pipeline under cathodic protection must have sufficient test points for electrical measurement to determine the adequacy of cathodic protection. Test points should be shown on a cathodic protection system map.

(d) Internal Corrosion Inspection

Whenever a section of pipe is removed from the system, the internal surface must be inspected for evidence of corrosion. Remedial steps must be taken if internal corrosion is found.

(e) Records

Operators must maintain records or maps of their cathodic protection system. Records of all tests, surveys, or inspections required by the pipeline safety code must be maintained.

Principles and practices of cathodic protection

Corrosion is the deterioration of metal pipe. Corrosion is caused by a reaction between the metallic pipe and its surroundings. As a result, the pipe deteriorates and may eventually leak. Although corrosion cannot be eliminated, it can be substantially reduced with cathodic protection.

An example of bare steel pipe installed for gas service. Note the deep corrosion pits that have formed. Operators should never install bare steel pipe underground. Operators should use either polyethylene pipe manufactured according to ASTM D2513 or coated steel pipe as new or replacement pipe. If steel pipe is installed, that pipe must be coated and cathodically protected.

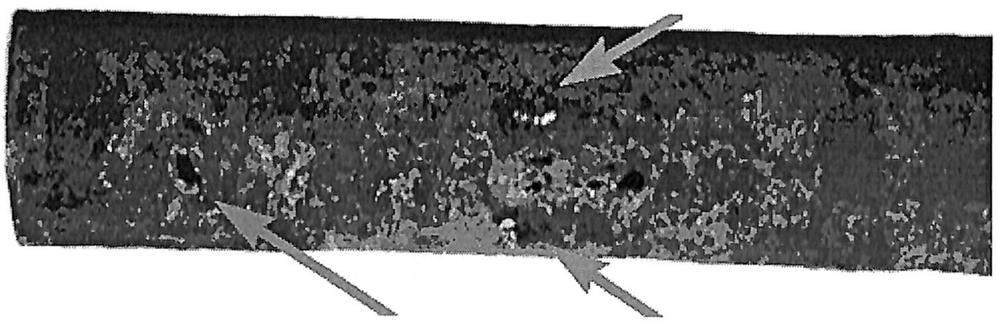

Fig.4 bare pipe -not under cathodic protection

Cathodic protection is a procedure by which an underground metallic pipe is protected against corrosion. A direct current is impressed onto the pipe by means of a sacrificial anode or a rectifier. Corrosion will be reduced where sufficient current flows onto the pipe.

Anode (sacrificial) is an assembly consisting of a bag usually containing a magnesium or zinc ingot and other chemicals, which is connected by wire to an underground metal piping system. It functions as a battery that impresses a direct current on the piping system to retard corrosion.

Sacrificial protection means the reduction of corrosion of a metal (usually steel in a gas system) in an electrolyte (soil) by galvanically coupling the metal (steel) to a more anodic metal (magnesium or zinc) . The magnesium or zinc will sacrifice itself (corrode) to retard corrosion in steel the pipe. Zinc and magnesium are more anodic than steel. Therefore, they will corrode to provide cathodic protection for steel pipe. Rectifier is an electrical device that changes alternating current (a.c.) into direct current (d.c.). This current is then impressed on an underground metallic piping system to protect it against corrosion.

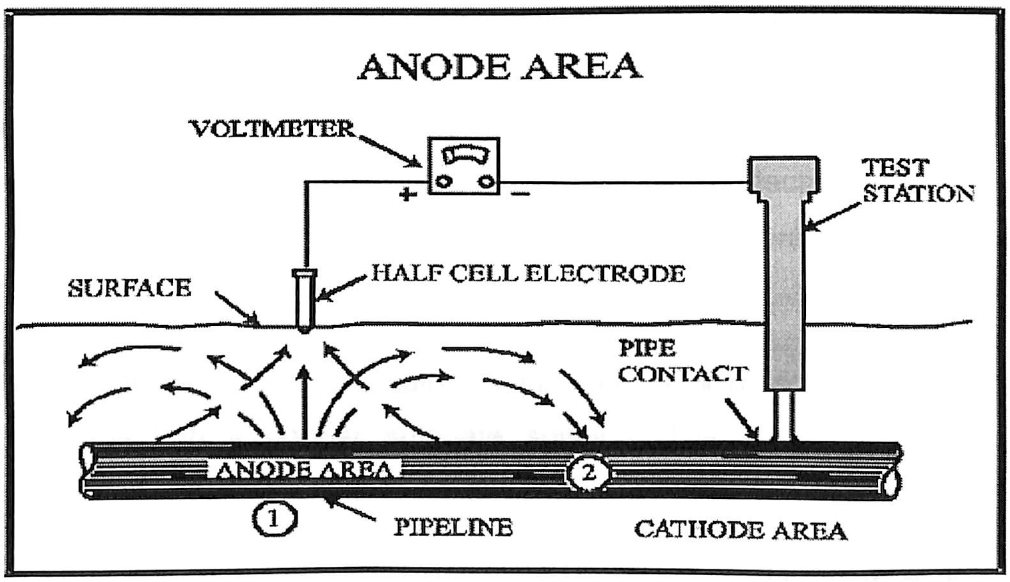

Fig.5 voltage potential

The voltage potential in this example is the difference between points 1 and 2. Therefore, the current flow is from the anodic area (1) of the pipe to the cathodic area (2). The half-cell is an electrode made up of copper immersed in copper-copper sulphate ($Cu-CuSO_4$).

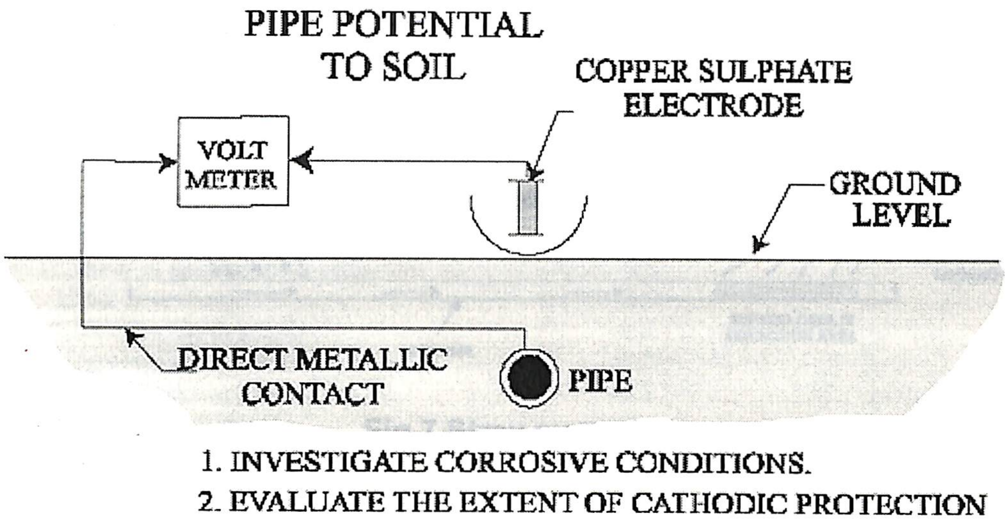

Fig.6 Pipe-to-soil

Pipe-to-soil potential is the potential difference (voltage reading) between a buried metallic structure (piping system) and the soil surface. The difference is measured with a half-cell reference electrode (see definition of reference electrode that follows) in contact with the soil. If the voltmeter reads at least –0.85 volt, the operator can usually consider that the steel pipe has cathodic protection. Also take into consideration the voltage (IR) drop that is the difference between the voltage at the top of the pipe and the voltage at the surface of the earth.

Reference electrode (commonly called a half-cell) is a device which usually has copper immersed in a copper sulphate solution. The open circuit potential is constant under similar conditions of measurement.

Short or corrosion fault means an accidental or incidental contact between a cathodically protected section of a piping system and other metallic structures (water pipes, buried tanks, or unprotected section of a gas piping system).

Stray current means current flowing through paths other than the intended circuit. If pipe-to-soil readings fluctuate, stray current may be present.

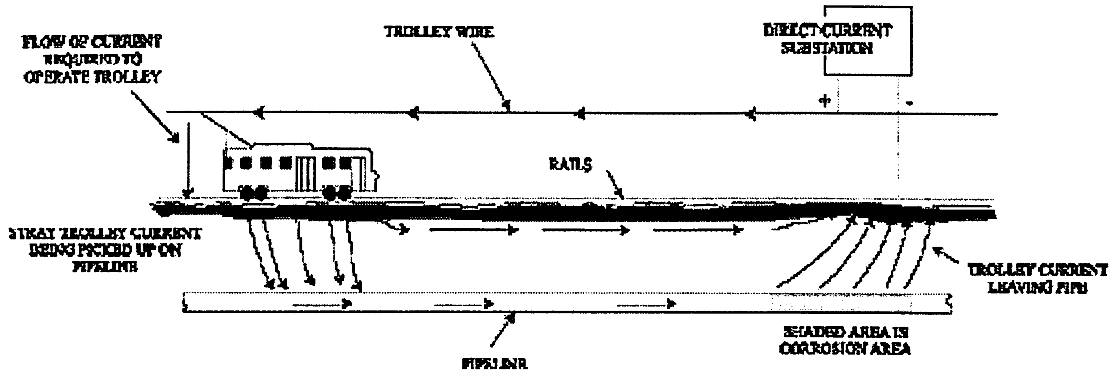

Fig.7 Stray current

This drawing illustrates an example of stray d.c. current getting onto a pipeline from an outside source. This can cause severe corrosion in the area where the current eventually leaves the pipe. Stray current corrosion means metal destruction or deterioration caused primarily by stray d.c. affecting the pipeline.

Galvanic series is a list of metals and alloys arranged according to their relative potentials in a given environment. Galvanic corrosion occurs when any two of the metals in TABLE 1 are connected in an electrolyte (soil). Galvanic corrosion is caused by the different potentials of the two metals.

TABLE 1

METAL	Potentials VOLTS*	
Commercially pure magnesium	-1.75	Anodic
Magnesium alloy (6% A1, 3% Zn, 0.15% Mn)	-1.6	
Zinc	-1.1	
Aluminum alloy (5% zinc)	-1.05	
Commercially pure aluminum	-0.8	
Mild steel (clean and shiny)	-0.5 to -0.8	
Mild steel (rusted)	-0.2 to -0.5	
Cast iron (not graphitized)	-0.5	
Lead	-0.5	
Mild steel in concrete	-0.2	
Copper, brass, bronze	-0.2	
High silicon cast iron	-0.2	
Mill scale on steel	-0.2	
Carbon, graphite, coke	+0.3	Cathodic

* Typical potential in natural soils and water, measured with respect to a copper-copper sulphate reference electrode.

Fundamentals of corrosion theory

In order for corrosion to occur there must be four parts: An electrolyte, anode, cathode, and a metallic return path. A metal will corrode at the point where current leaves the anode. Dissimilar soils may create an environment that enhances corrosion. There are two basic methods of cathodic protection: the galvanic anode system and the impressed current system.

Galvanic anodes are commonly used to provide cathodic protection on gas distribution systems. Impressed current systems are normally used for transmission lines. However, if properly designed, impressed current can be used on a distribution system.

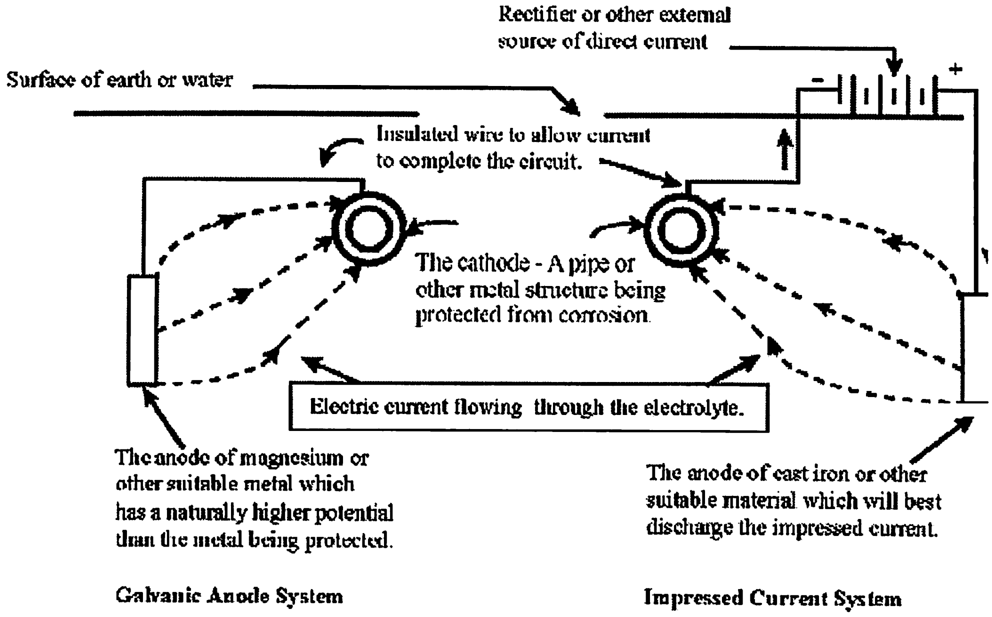

Fig. 8 Galvanic Anode System

Galvanic Anode System-- Anodes are "sized" to meet current requirements of the resistivity of the environment (soil). The surface area of the buried steel and estimated anode life determines the size and number of anodes required. Anodes are made of materials such as magnesium (Mg), zinc (Zn), or aluminum (Al). They are usually installed near the pipe and connected to the pipe with an insulated conductor. They are sacrificed (corroded) instead of the pipe.

Impressed Current Systems-- Anodes are connected to a direct current source, such as a rectifier or generator. These systems are normally used along transmission pipelines where there is less likelihood of interference with other pipelines. The principle is the same except that the anodes are made of materials such as graphite, high silicon cast iron, lead-silver alloy, platinum, or scrap steel.

Criteria for cathodic protection

There are five criteria listed in Appendix D of Part 192, to qualify a pipeline as being cathodic protected. Operators can meet the requirements of any one of the five to be in compliance with the pipeline safety regulations. Most systems will be designed to Criterion 1.

Criterion 1: With the protective current applied, a voltage of at least -0.85 volt measured between the pipeline and a saturated copper-copper sulfate half-cell. This measurement is called the pipe-to-soil potential reading.

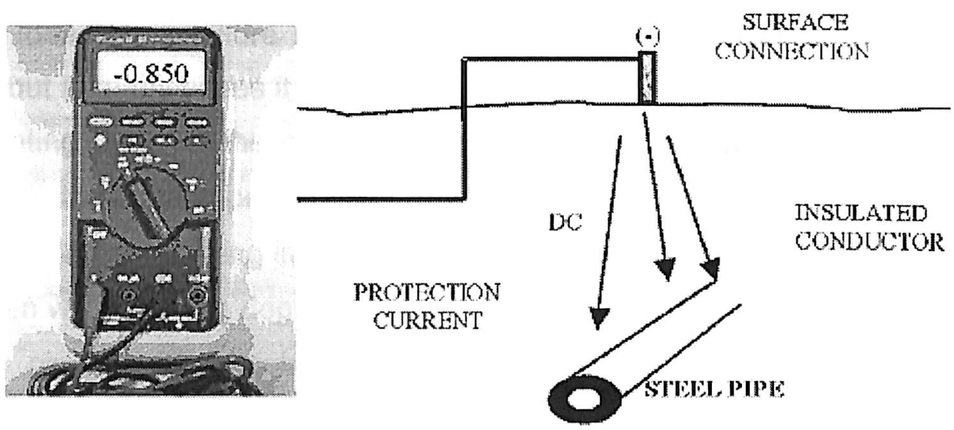

Fig.9 Criterion 1 for cathodic protection

If meter reaches at least -0.85 volt, the operator knows that the steel pipe is under cathodic protection. If not, remedial action must be taken promptly (also take into consideration the voltage drop).

Coating

An ideal coating will stop pipeline corrosion. The minimum requirement is that a coating should stop corrosion for the design life of the pipeline but a more realistic objective is that the coating should stop corrosion for as long as the pipeline remains in service. Most pipelines are operated well beyond the original design life. Inevitably coatings get damaged by external forces or by a number of long term degradation processes that affect the constituents of the coating. Typically these results in coating defects that expose the pipe steel to the environment around the pipeline and this corrosion risk can be controlled by cathodic protection. Many coatings also show a loss of adhesion such that water or soil penetrates between the pipe and the coating. Ideally this failure mode should not create new corrosion threats to the pipeline but in many cases it does.

For operating pipelines the key coating issues can be resolved into three questions.

- How is the coating performing?
- How does the coating impact on monitoring and maintenance costs?
- When will a coating degrade to the point at which it is no longer sustainable?

For new pipelines the problem is simpler. Fore-warned with hindsight, from the experience of others, an operator can select the coating system and application conditions that will guarantee a long, low maintenance life for the pipeline.

Coating application

Current coating use on high pressure pipelines is dominated by FBE and 3LPE with 3LPP finding increasing use for high temperature applications above the acceptable temperature range for mono-layer FBE or PE. The proportionate cost of each of these surface preparation procedures is typically 2 – 3% of the total applied coating cost and the heating is typically no more than 10%. The major cost in any pipeline coating project will be the coating material which will be 50% for stand-alone FBE and more than 60% for the FBE, adhesive and PE in a 3LPE coating. Costs will vary from project to project and with plant location but the applied cost of 3LPE coatings are typically ~25% more than stand alone FBE. MCL coatings for field joints typically turn out 5 – 6% higher than field applied FBE and '3-layer' heat shrink materials undercut field applied FBE by ~20%.

Current coatings – 3LPE

One of the first methods of applying polyethylene (PE) to pipelines was by sintering or fusion of the polymer directly onto the prepared steel substrate. This was followed by the mastic adhesive / PE pipeline protection system (mastic / plastic) that has been used to protect pipe up to 250mm in diameter, and by a two layer system with a "hard" polymer adhesive. In order to improve the capability of the 2-layer polymer adhesive / PE system a 2-pack liquid epoxy coating was applied between the cleaned and profiled substrate and the polymer adhesive. This 2-pack epoxy coating forms a mechanical bond with both the substrate and the intermediate, adhesive polymer layer.

The overall coating thickness will depend on the density of the PE used, diameter of the pipe and the use to which the coated pipe will be put. Generally the thickness is between 1.5mm and 4.2mm. Three layer PE coatings can be operated at around 60^0 C with LDPE, and 80^0C for MDPE/HDPE. Three layer PP systems can currently be operated at up to 110 deg. C

Current coatings - FBE

Fusion bonded epoxy powder (FBE) was introduced in the late 1950's, for the coating of small diameter pipe but the FBE performance did not meet the requirements for large diameter, high pressure pipe. Formulators, resin manufacturers and pipeline operators worked together in the 1970's to produce FBE's with acceptable chemistry and protective properties. Subsequently many thousands of kilometers of pipelines have been coated with FBE, particularly in the Middle East, UK, and North America.

The achievement of 'good' surface preparation is critical to the success of FBE coatings in protecting pipelines. Hygroscopic salts remaining on the pipe surface, under the FBE coating, can cause blistering and loss of adhesion. In the early 1980's both phosphoric acids cleaning and chromate pre-treatment were introduced to the FBE pipe coating industry. Phosphoric acid, in association with abrasive blast cleaning, cleans the surface of the pipe and removes the majority of contaminants, including hygroscopic / soluble salts. Chromate pre-treatment modifies the surface chemistry of the substrate and thus provides a surface to which FBE's have a better adherence.

FBE systems whatever the type of FBE being applied the achievement of an excellent degree of surface preparation remains the most important overall factor can be also applied in the field for the protection of field joints.

Cause of Paint and Coating Failures

The majority of paint and coating-related failures can be attributed to six primary causes. These causes are as follows.

- **Improper surface preparation** – the substrate surface is not adequately prepared for the coating that is to be applied. This may include cleaning, chemical pretreatment or surface roughening.
- **Improper coating selection** – either the paint or coating selected is not suitable for the intended service environment, or it is not compatible with the substrate surface.
- **Lack of protection against water and aqueous systems** – this is a particularly serious problem with aqueous systems containing corrosive compounds such as chlorides.
- **Mechanical damage** – which results from improper handling of the painted or coated substrate, resulting in a breach in the paint or coating.

3.9 STUDIES FOR CORROSION CAUSES & THEIR REMEDIES

1. **Coating Inspection IS Quality Control---** Flow efficiency coatings may reduce the friction coefficient across a carbon steel surface by up to 50%, allowing transmission increases of 15 to 25%.

2. **Ultra well coated pipelines---** Once upon a time pipelines had a coating conductance. The coating would gradually break down over its length and draw more CP current. Attenuation equations, which are still used for cathodic protection design, are based this uniform coating breakdown. However pipeline coatings have improved to the extent that some new pipelines are more like cables. They are an insulated conductor with perhaps, over a 100km, a couple of defects in the insulation. This has profound affects on cathodic protection that the industry has yet to address.

3. **Reference a novel Multi Electrode for corrosion monitoring of steel reinforcements in concrete structures---** In order to monitor initiation and occurrence of localized corrosion in reinforced concrete structures, and hence to ensure their durability, a multi-reference electrode (MuRE) system has been developed and is now proposed. It consists of continuous and partially insulated nickel wires, suitable to measure the potential of steel rebar and high strength steel tendons in pre-stressed or post tensioned structures. The MuRE system is able to promptly detect and also to localize the occurrence of chloride induced corrosion as well as other types of corrosion, induced by carbonation or by electrical interference. Each electrode of the MuRE system, once corrosion has started, behaves as an interfered electrode crossing the equipotential surfaces of the electrical field generated by the corrosion macro cell. Laboratory tests and computer simulations confirmed that the potential reading by a MuRE can be interpreted as the average potential weighted on the crossed equipotential surfaces. Several applications of the MuRE have been investigated. In steel tendons encased into a duct, as it is the case of post-tensioned structures, the probe allows to detect the occurrence of localized

corrosion. In pre-compressed concrete pipes (PCCP) the MuRE system can be installed to monitor pitting initiation and to prevent risks of hydrogen embrittlement. Using computer modeling simulations, the maximum active length of the reference electrode has been calculated as a function of maximum potential variations.

4. Corrosion of welded stainless steel-carbon steel bars in chloride contaminated--- The corrosion behavior of stainless steel-carbon steel bars, tied together and placed in corrosive environments, was recently studied and results were reported. This work should that joining these two different metals in concrete does not create a large galvanic effect, specially when the chloride contamination is low.

5. Delaminations of organic coating (The role of polymer relaxation concrete) --- in various situation the organic coating can cause pitting, crevice corrosion and delaminations, which is caused by the corrosive environment containing water, oxygen and various activator ions such as sodium and chloride. The organic coating containing electro active polymer for the purpose of replacement for chromate, which is environmentally unfriendly corrosion passivator, and electro active polymer can be doped with any proper passivator such as sodium moylbdate before applying the organic coating on the surface of the steel. This (Molybdate ions) can be subsequently released once corrosion starts in the organic coating in the form of small pitting underneath the coating (Anodic delamination) or due to disbondment or peeling off of the organic coating and subsequent corrosion (cathodic delamination). The moylbdate ions will be released because of the corrosion current effect on the electro active polymer.

6. Microbiologically Influenced Corrosion - Aspects of microbial corrosion were first published in the 1920's. MIC has always been a significant materials issue in many industrial enterprises, ranging from food processing, power generation, wastewater treatment, marine industries, pulp and paper processing, the oil and gas industry, and others. These industries all involve the use of process water which can become contaminated with microorganisms that support MIC. MIC is initiated and propagated by certain types of micro-organisms such as sulphate-reducing bacteria (SRB), sulphur-oxidising bacteria (SOB), iron-reducing bacteria (IRB), iron-oxidising bacteria (IOB), and various slime-forming organisms.

7. Influence of cement content of chloride-induced reinforcement corrosion in the presence of cracks--- The minimum cement content in current codes of practice to ensure durability of concrete is being increasingly questioned. This is likely to be more severe in the presence of defects (eg. Cracks) in the concrete surface. The influence of variation in cement content (above and below the limits in current European standards) at fixed w/c ratio, on chloride-induced reinforcement corrosion of concrete with intersecting cracks under static loading conditions was studied. Concrete made with limestone/OPC was used as the aggregate characteristics, particularly high porosity limestone; in the current standards for concrete durability appear to be often overlooked. The crack width was varied from 0.1 to 0.5 mm. The cement reduction below the given limits has no influence on the chloride-induced corrosion in the presence of intersecting cracks in the concrete surface. There may be the possibility to increase current permissible crack width for reinforced concrete structures in aggressive environments from 0.3 to 0.5 mm when intersecting cracks are likely in concrete structures under static loading conditions.

8. Design and implementation of a modular high current Power supply for CathodicProtection use--- Switchmode power conversion technology provides a way of delivering controllable DC high currents for impressed current cathodic protection. The new CP rectifier provides advantages over conventional SCR or variable autotransformer control in size, efficiency and includes integrated control and monitoring.

9. Advanced Two Layer Polyethylene Coating Technology For Pipeline Protection--- Oil and Gas pipelines are protected by various types of external coatings in conjunction with CP systems. Two of the major coatings use polyethylene as their top-coat: a) two layer and b) three layer. The existing two layer system uses an adhesive that is mastic based. It provides excellent corrosion resistant properties but has a relatively low shear resistance in the adhesive layer, particularly at higher temperatures. The three layer system uses a hot melt adhesive to provide excellent shear properties and an epoxy layer which provides the corrosion resistance. Both are excellent coatings used in the proper environment. The major difference between the two systems is the mechanical properties at higher temperatures and the cost. The new coating uses a hybrid adhesive which combines both the mastic and the hot melt functions, hence providing excellent corrosion resistance and adequate shear properties to withstand pipe movement and eliminates any stockpiling and handling problems in high climate temperatures.

10. On Site Corrosion Rate Measurements--- The linear polarization resistance (LPR) method is one of the most effective non-destructive field techniques currently available to evaluate the instantaneous corrosion rate of steel reinforcing bars in concrete structures. Because corrosion is a dynamic process it may fluctuate over time with changes in the ambient environmental conditions. Measurements of the instantaneous corrosion rate may therefore be affected by a number of factors including chloride concentration, temperature, relative humidity, changes in the concrete alkalinity and resistivity. In addition there are also a number of important practicalities that must be considered when undertaking an LPR measurement on an actual structure on site. These include the location of the reading, the connection to the rebar, the equilibrium period and the potential shift required. Thus there can be considerable practical difficulties in assessing the ongoing corrosion rate for reinforced concrete structures in the field using the LPR method.

11. **Affect of Variability in the corrosion coatings on the corrosion resistance of painted galvanized steel sheets--** The role of conversion coatings in improving the adhesion and corrosion resistance of painted galvanized steels is well known. Different commercial types including phosphate, chromate, chrome-phosphate and complex oxide types are currently available and used for this purpose with various degree of success, the later two being more common in use.

12. **New Coating Generations Offer Effective Solutions for Rehabilitation of Buried Pipelines---** Protective coatings have been the most cost effective passive corrosion control method utilized for the last five decades as first line of defense against corrosion. The use of liquid coatings on new pipelines has not been successful compared to fusion bonded epoxy (FBE) in Subkha ground. Also, for rehabilitation of buried pipelines, achieving good surface preparation is still one of the main factors to cause liquid coatings premature failures of liquid coatings. Few years ago, Saudi Aramco started investigating alternative coating systems that are surface tolerant and having reliable chemical and mechanical properties for the external protection of pipelines in Subkha ground. Visco-elastic non-curable coatings from different generic materials have been tested, qualified and successfully used as stand alone coatings for external protection of buried pipelines.

13. **Kinetics of pH variation at near electrode electrolyte layer of cathodically protected main pipeline---** During cathodic polarization of a main pipeline surface formation of an electric double layer occurs because of hydroxyl ions which are adsorbed onto the steel surface. Thereby a pH value of a near-electrode layer varies. A pH value depends on initial parameters of ground environments, such as acidity, a lithologic structure, moisture of soil as well as an action of a cathodic protection i.e. a polarization potential.

3.10 MAKING DECISIONS ON PIPELINE RENEWAL

A balance between system performance and costs is the essence of decision making on the renewal of infrastructure systems. It is widely accepted that performance criteria for pipeline must include quality, quantity and reliability components. The costs involved in a pipeline system comprise capital investment in system design, installation and renewal, operation and maintenance (energy, materials, labour, monitoring, inspection, and repair) and indirect and social costs resulting from failure (property damage, disruption, illness, etc.).

What makes the decision process so challenging for pipeline is: mechanisms affecting the performance criteria are not well understood; it is difficult to define and measure performance,

Failure risk in a pipeline network

The failure of a pipeline system is broadly defined as the inability to meet any of the performance criteria discussed above.

As pipes age they deteriorate, resulting in increased failure frequency. For buried pipes one can define the risk of any type of failure as the expected magnitude of the consequences of failure(s), i.e.

Risk of failure = E(failure consequence) = f(probability of failure, costs of failure)

Probability of Failure (failure frequency)

The probability of failure can be assessed in different ways, some more rigorous than others, depending on the type of failure and on the available data.

Consequence (Cost) of Failure

The costs of a pipeline system failure event may be classified into three categories: (a) direct, (b) indirect, and (c) social costs. While direct costs are relatively easy to quantify in monetary terms, indirect costs may require much more effort, and social costs are often the most difficult to describe and assess.

Risk of Failure

Risk mitigation can be achieved by reducing both probability and/or the cost of failure, as risk depends on both. As was stated earlier, the probability of failure increases as the distribution system ages and deteriorates. In some cases, it can be argued that the cost of failure is also likely to increase over time, for example, when a pipe is located in a rapidly developing area, but generally it is assumed that failure cost is not time-dependent. Measures to mitigate risk from the cost side are possible but rather limited in scope, e.g. timely response by a well-trained pipe repair crew will reduce the cost of repair as well as product loss and collateral damage resulting from a main break.

It appears that mitigating risk on the failure frequency side has a greater potential because theoretically, one can reduce failure frequency to nearly zero (thus reducing risk to nearly zero) albeit at a very high cost. It follows that a rigorous decision process should find a balance between the risk of failure and the cost to mitigate it.

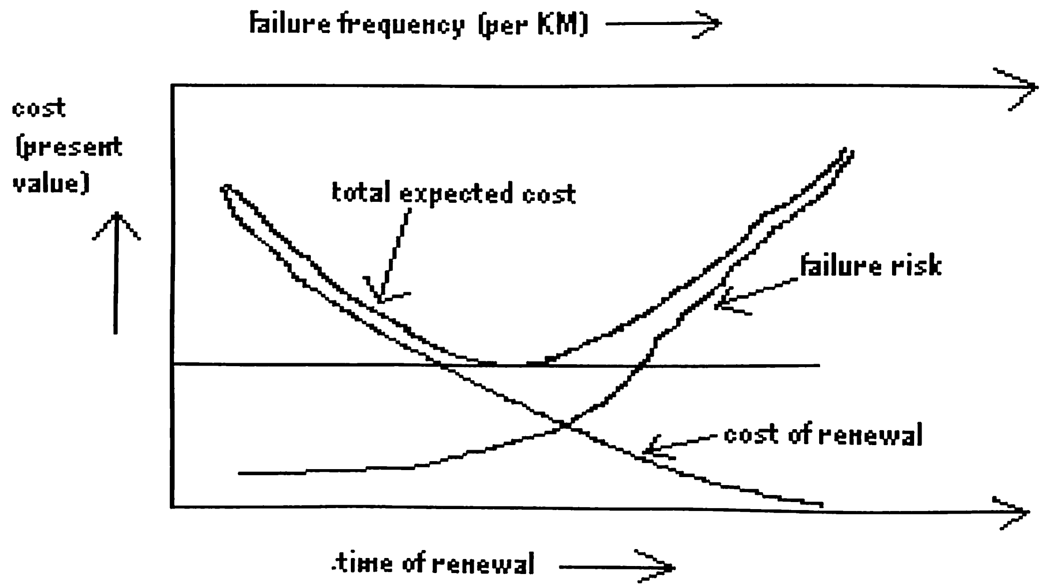

Fig. 10 Deciding when to renew a pipeline with a high cost of failure.

Fig.11 illustrates how this balance varies over time. As long as the pipe continues to age and deteriorate without renewal, its probability of failure (or failure frequency) increases and the risk increases as well (note that here the risk is expressed in discounted expected cost). The total expected life-cycle cost (sum of the total expected cost of failure and cost of renewed pipe) typically forms a convex shape, whose minimum point depicts the optimal time of renewal (t^*).

High failure costs may justify the use of extra measures to anticipate failures and prevent them in a pro-active approach. These measures could include inspection and condition assessment using non-destructive evaluation (NDE) techniques in conjunction with physical/mechanical models. As the costs of NDE techniques decrease, the justification for applying them to small pipes with low cost of failure will also increase. It should be emphasized that the life-cycle cost curves depicted in Figs. 10 are qualitative and idealized. True costs are often hard to come by and are subject to large variations, as are true deterioration rates

CHAPTER -4

MAINTENANCE PLAN FOR PIPELINE

Project work involves a 1000Kms long 20" × 0.281" size pipeline transporting gas.

The pipeline comprises of 10 stations for the effective maintenance one central maintenance station, three base maintenance stations and five local maintenance stations have been envisaged.

Maintenance activity to be covered by central maintenance station , base maintenance station and local maintenance station have been worked out together with the required manpower , equipments , tools , instruments , pipe length , pipe fittings ,and other miscellaneous items .maintenance frequency also have been worked out on the basis of literature/ industrial practices . The maintenance model, brought out, in this report, may be useful to pipeline operators.

TITLE OF THE PROJECT – Maintenance of pipeline

OBJECTIVE – To develop a maintenance plan and to bring out the required resources (for mainline)

DETAILS OF PIPELINE –

- Length--- 1000Kms
- Size--- 20" × 0.281"
- Type of coating--- 3 layer polyethylene (LPE)
- No. of cathodic protection station--- 20
- No. of River crossing--- 5 (submerged)
- No. of cased crossings --- 100
- No. of compressor station--- 10
- Capacity of pipeline--- 5 MMSCMD

TYPES OF MAINTENANCE FREQUENCY

Main line maintenance ---

- ROW (right of way)
- CP (cathodic protection)
- Valves
- Crossings
- Washouts
- Erosion at river bank
- Arial crossing

FREQUENCY FOR PIPELINE MAINTENANCE

Maintenance Activity	Maintenance Schedule/Frequency	Requirement/Remarks
ROW inspection	Annual	CSA Z 662: (2003) Sour gas(>10Moles H2S/k-mole NG) required monthly/bimonthly -HVP/sour condensate: bimonthly/weekly depending on class location
Pipeline patrol/leak detection/corrosion (gas)	Monthly (gas)	Industry norm, B31 requires periodic/as required—leak and corrosion survey report kept while line in service
	Biweekly (liquids): LPG/NH3 lines<1 week in common areas	ASME B31.4 (1998)
Pipeline patrol (gas lines)	Class 1,2: Annual Class 3: 6 months Calls 4: 3 months	ASME B31.8 (1999)
CP monitoring	Annual, not to exceed 15 months	ASME B31.1 (1999)
CP: Pipe to soil potential and rectifier readings	Monthly, Soil survey once per year	Industry norm
Internal corrosion monitoring	< 6 months	ASME B31.4 (1998): if line internally coated, pigged, dehydrated/corrosion inhibition, corrosion coupon used
Exposed pipe: External monitoring;	<3 years	ASME B31.4 (1998)
Encroachment assessment	Periodic or annual	
Class location assessment (Gas line)	Annual	ASME B 31.8 (1999)
Valve inspection/operation	Annual	ASME B31.4 and B31.8, Partial operation required
Valve testing	Annual	
Remote control shutdown devices	Annual	B 31: For functionality test
Relief valves (liquid)	< 5 years	ASME B31.4 (1999): LPG/CO2/ NH3 Line/Storage

MAINTENANCE ORGANIZATION----This organization consists of base station, central station, and skeleton crew station (local station).

- Central station is located at a distance of 500Km from the start point of the pipeline.
- Base stations are located 300Km, 600Km, and 900Km from the start point of the pipeline.
- Skeleton crew station are located at 0Km,50Km,400Km,700Km,1000Km from the start point of the pipeline respectively.

S. No.	TYPE OF STATION	TYPE OF WORK	STAFF	NO. OF STATION
1.	Central Station	Critical Work	Manager, senior engineer, three engineers, assistants and technicians	1
2.	Base station	Major work	Senior engineer ,two engineer, technicians	3
3.	Skeleton crew station	Small work	Engineer and technicians	5

MAINTENANCE RESOURCES (LOCATION WISE)

1. **Resources for central station—**

- **EQUIPMENT**—compressors, welding generators , hot tapping machine cold cutting machine, lineup clamp, crane, side boom truck, trailer, tyres mounted tank, communicating facility , pigs.
- **TOOLS**—valve repairing tools, set of pipe/chain, wrenches, spanner sets.
- **INSTRUMENTS**—holiday detector, pit gauge, explosive meters, multimeters, half cell and pipeline locator.
- **MANPOWER**— manager, engineer, technician, welder, foreman.
- **PIPE AND OTHER MATERIAL** – one % length or longest crossing, leak clamp,, weld plus ends, coating material, hot tapping fitting ,welding rods ,wooden ballies , shuttering material , dewatering pump, tent and camp material.

2. **Resources for base station—**

- **EQUIPMENT**—welding generators, hot tapping machine cold cutting machine, lineup clamp, crane, side boom truck, trailer, communicating facility.
- **TOOLS**—valve repairing tools, set of pipe/chain, wrenches, spanner sets.
- **INSTRUMENTS**—holiday detector, pit gauge, explosive meters, multimeters, half cell and pipeline locator.
- **MANPOWER**—engineer, technician, welder, foreman.
- **PIPE AND OTHER MATERIAL** – one % length or longest crossing, leak clamp,, weld plus ends, coating material,. hot tapping fitting ,welding rods , dewatering pump, tent and camp material.

3. **Resources for skeleton crew station (local maintenance station)—**

- **EQUIPMENT**—welding generators, hot tapping machine cold cutting machine, lineup clamp, trailer, communicating facility.
- **TOOLS**—valve repairing tools, wrenches, spanner sets.
- **INSTRUMENTS**—holiday detector, pit gauge, explosive meters, multimeters, and pipeline locator.
- **MANPOWER**—engineer, technician, welder, foreman.
- **PIPE AND OTHER MATERIAL** – leak clamp,, weld plus ends, coating material, hot tapping fitting ,welding rods , tent and camp material.

AGENCIES --- lined-up in advance for the jobs to be outsourced.

CONCLUSION

The maintenance of oil and gas infrastructure is critical for safety and performance, but the challenges presented by the conditions and materials ensure that new maintenance efforts are emerging all the time. In any industry, assets deteriorate over time. Equipment wears out. Tools need replacing, and infrastructure requires maintenance. But the matter is particularly pressing in an industry such as the oil and gas industry. As such, regular and effective maintenance to the equipment and infrastructure is absolutely vital to the industry.

"If maintenance isn't properly undertaken then there would undoubtedly be an increased number of unscheduled breakdowns," emphasizes Grace Baxter, Lead Maintenance Engineer at the Oil and Gas Division of project management and services company AMEC. " . One could have pipeline upsets, and that would greatly reduce product throughput. But more importantly, if one have leaks or escapes of gas then that is a safety issue. So the main focus is ensuring the integrity of equipment is adequate to ensure that one don't have any conditions on the pipeline that would be a danger first of all to the personnel and secondly to the equipment and the pipeline."

However, there has also been a more fundamental change, a shift in mindset. The industry is now looking to pre-empt problems, and negate any costly shutdowns or performance dips altogether. Technologies are increasingly developed to flag up any potential problems rather than react once they occur. And maintenance support strategies are increasingly focusing on how the most fundamental tools – the workers – can also be finely tuned to identify and rectify such problems. All of these developments point to a safer and more efficient industry for the future.

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