# OFFSHORE PIPELINE PROBLEMS AND REMEDIAL MEASURES

A

Project Report submitted
In the partial fulfillment
Of the award of the

**Master of Technology**

In
**Gas Engineering**

By

**ANUJ AGRAWAL**
RO30205003

Under the guidance of

Mr. R.P. SHRIWAS
Course Coordinator
Pipeline Engg. Deptt.



UNIVERSITY OF PETROLEUM & ENERGY STUDIES
Dehradun2007

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# CERTIFICATE

This is to certify that, this is the bonafide record of the major project work entitled **"OFF SHORE PIPELINE PROBLEMS AND REMEDIAL MEASURES"** carried out by the student **Mr. Anuj Agrawal** of final year M.Tech (Gas Engineering) college of engineering, during the academic year 2007 in partial fulfillment of the requirement for the award of degree of Master Of Technology to the university of petroleum and energy studies.

04/06/2007

Mr. R.P.SHRIWAS
Course Coordinator
Pipeline Engineering Department

04.06.07

Dr. B.P. PANDEY
Dean, CES.

**Corporate Office :**
Hydrocarbons Education & Research Society
3rd Floor, PHD House 4/2, Siri Institutional Area
August Kranti Marg, New Delhi-11001 India
Ph + 91-11-41730151-53 Fax : +91-11 1730154

**Main Campus :**
Energy Acres, PO Bidholi, Via Prem Nagar,
Dehradun-248 007 (Uttaranchal) India
Ph. : +91-135-2261090-91, 2694201/203/208
Fax : +91-135-2694204

**Regional Centre (NCR) :**
SCO 9-12, Sector-14, Gurgaon 122 007
(Haryana), India
Ph : + 91-124-4540300
Fax : +91 124 4540 330

E-mail : info@upes.ac.in URL:www.upes.ac.in

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Anuj Agrawal
04/06/07

*Anuj Agrawal*
*MTech. (Gas Engg.)-IVth sem.*
*R030205003*
*UPES, Dehradun(U.K.)*

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# ABSTRACT

India as a developing economy needs energy to sustain its developments, before 1991 oil and gas sector was almost closed for the outside world. But by liberalizing the oil and gas sector the government has taken the major steps towards meeting the energy demand. India has introduced NELP (new exploration licensing policies) to instigate the E&P activity in the country. Recent discoveries show that major hydrocarbon potential lies not on the land but in the deep water areas, E&P companies all over the world not only in India are moving towards deep water areas to explore oil and gas, though it is costly to find and produce oil and gas in deep water area but high oil and gas prices justify this effort. If we talk about the production facilities which the E&P companies uses are generally designed for long service periods and workability in the moisture. The basic advantage the production facilities have is that they operates above sea level and maintenance cost are not quite high as maintaining facilities below sea level.

Now if we talk about the transportation facilities which are used to carry oil and gas from production facilities to nearest shore where it can be sent to the centre of consumption first and most important things which causes to mind is pipeline, which lies below the sea level and subjected to many unbalance forces and adverse condition. These pipelines does not have the benefit of operating above the sea level as the other facilities have so the maintenance of pipelines is very costly and required substantial amount of reserve and owing these resources may be not possible or feasible for small scale companies or medium scale companies, so the question these companies need to ask themselves is how they can identify the types of failures and their sources, the methods of detection and economic front the cost benefits analysis and what strategies they can pursue to get resources at affordable price.

So keeping in mind, this project focus on identifying the different types of failures a offshore pipeline can subjected to and the various methods which are used worldwide to identify these problems and the remedial measures for these failures.

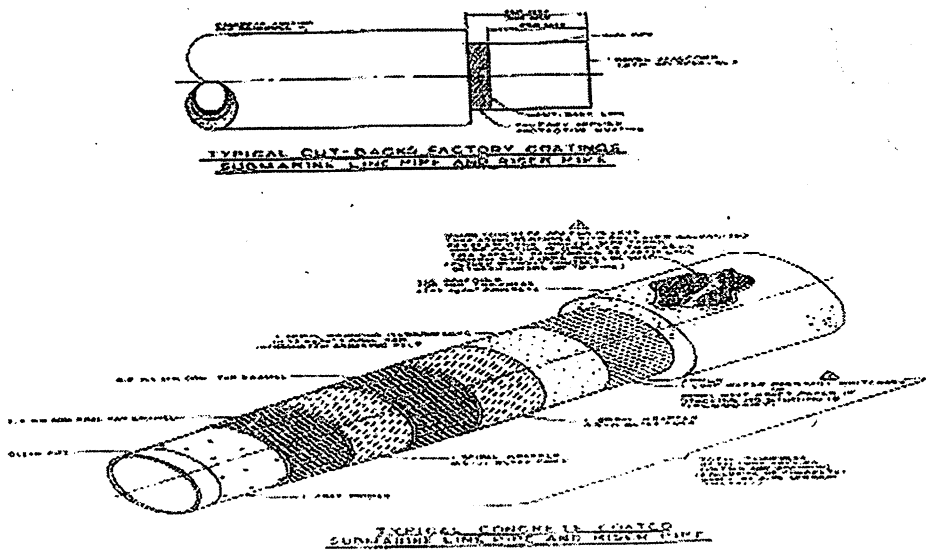
Having detected the leak, the biggest problem arises as to how overcome the problem? Whether requisite facilities, material and manpower resources readily available for such jobs? Often if causes difficulties and delays.

Through this project, an attempt has been made to explore the possibility if the resources can be pooled amongst the indigenous sub sea pipeline operator or with the pipeline operating in neighbouring country through centralized resources or through mutual aid schemes within the purview of national/ international regulations.

# RELAVENT DETAILS FROM LITERATURE ON OFFSHORE PIPELINE AND RELATED ISSUES

## 1.0 INTRODUCTION TO OFF SHORE PIPELINE

Initially, a offshore pipeline was a pipe, made of carbon steel which was placed on continental shelf to transport oil and gas from offshore well to land. Little efforts was made to insure that it was buried in the sand. There was a little problem because the pipe, in some cases had nearly positive buoyancy. This led to the need to the weight the pipe down with concrete weights. Current technology provides for a complete covering of pipe with concrete.



*SOURCE: MONITORING OF OFFSHORE PJPELINES*

*FIG 1 OFFSHORE PIPELINE*

In most part of the world, the pipe joints for oil and gas will conform to the American Petroleum Institute API specifications 5L; for submarine pipeline the relevant specification is PSL2. Though the API 5L specification dated back to the 1920s, it became the basic international specification in 1948. at that time, the highest strengths grades was X42. the ISO standard now include pipe grades up to X80.

Typical composition of pipeline steels

| Pipeline Grade/Wall | | Maximum composition % | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | C | Mn | Si | Al $*10^2$ | Ca $*10^2$ | Ni | N $*10^2$ | Cu | V $*10^2$ | Nb $*10^2$ | Ti $*10^2$ | B $*10^3$ | P $*10^2$ | S $*10^2$ |
| X65 | 16mm | 0.02 | 1.59 | 0.14 | | | | | | | 4 | 1.7 | 1 | 1.8 | 3 |
| X65 | 25mm | 0.03 | 1.61 | 0.16 | | | 0.17 | | | | 5 | 1.6 | 1 | 1.6 | 3 |
| X65 | 25mm | 0.06 | 1.35 | | | | 0.25 | | 0.33 | | 4 | 1.8 | | 2.5 | 5 |
| X70 | 20mm | 0.03 | 1.91 | 0.14 | | | | | | | 5 | | 1 | 1.8 | 3 |
| X70 | 20mm | 0.08 | 1.60 | | | | | | 0.04 | | 7 | | | | |

**TABLE 1**

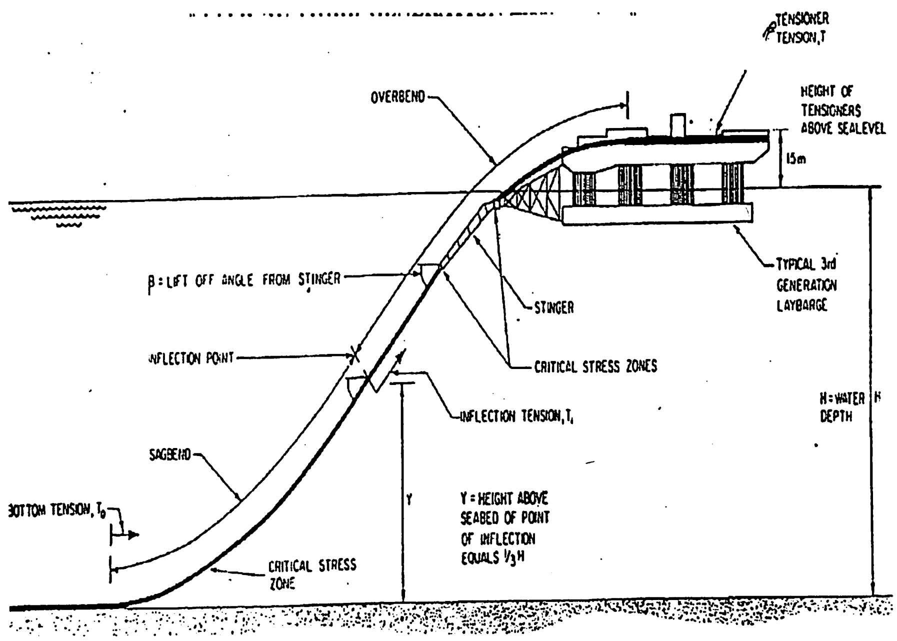
Submarine pipeline construction began in the late 1940's to facilitate the exploitation of hydrocarbon reserves in the Gulf of Mexico. Early equipment consisted of flat deck barges (pontoons) on which conventional land pipelaying equipment was temporarily mounted. During the 1950's the laybarge, a specialist vessel equipped for joining pipe section and handling the pipeline safely to the sea bottom, was developed.

In shallow water, pipelaying technique were developed by "trial and error" process. However through the 1960's and 70's increased water depth led to a more scientific approach and the developments methods capable of laying pipelines in 600m water depth. Most offshore pipelaying is performed by the lay barge methods. The various methods of pipeline laying are:

- Conventional Installation by Laybarge
- Installation by J Lay
- Tow Techniques
- Installation by Reelship

## S- Lay Method

The is traditionally method for installing offshore pipeline in relatively shallow water is commonly referred to as the S- lay method because the profile of the pipe as it moves in a horizontal plane from the welding and inspection station on the lay barge across the stern of the lay barge and on to the ocean floor forms elongated "S". as the pipeline moves across the stern of the lay barge and before it reaches the ocean floor, the pipe is supported by stinger- a truss-like structure is equipped with rollers and is known as stringer. The purpose of the stinger is to minimize the curvature, and therefore the bending stress, of the pipe as it leaves the vessel.




*SOURCE AN INTRODUCTORY COURSE IN MARINE PIPELINE ENGINEERING BY EIL,INDIA*

***FIG2 S-LAY METHOD***

### J-Lay Method

A comparatively new method for installing offshore pipelines in deepwater is the J-lay method. The method was so named because the configuration of the pipe as it is being assembled resembles a "J". lengths of the pipe are joined to each other by welding or some other means while supported in vertical or near vertical position by a tower.

## 1.1THE ECONOMICS INVOLVED IN THE USE OF SUB SEA PIPELINE

Because of large amount of oil and gas to be transported from offshore locations, no other methods of transport provides the unit cost advantages as does the sub sea pipeline. When amortized over its life it is less expensive than any other means of transportation. Even considering the high cost of laying the pipeline including by barge, pipe, manpower, and ocean going stabilizing tugs, the price is still cheap when compared with any other means of transportation.

## 2.0 TYPE OF PROBLEMS ENCOUNTERED IN OFFSHORE PIPEINE

Pipelines have an excellent record for safety and reliability, failures do occur from time to time. Sometimes they lead to leak, sometimes due to design failure and sometimes to serviceability failure such as equipments failure, blockage of pipeline that restrict or close off flow. To most instructive approach to minimize risk is to examine specific incidents and to try to learn lesson from them. They can be supplemented by reliability theory methods, which are being widely applied to rationalize codes and design practice, to gain a deeper understanding of the factors that govern reliability, and to provide a basis for the incorporation of new approach. Most failures result from mistakes. They are sometimes consequences of ignorance, sometimes the result of conscious risk taking to save money or to hasten completion of project, and sometime material or equipment failure.

Guarding against mistakes is a central part of the management of design and construction. It has various components, among them training, calculation checking, software validation, peer review, inspection, testing and quality assurance procedure that ensure the documentation and traceability of design decision and material procurement.

In an offshore pipeline several problems are generally encountered. Some problems encountered due to design errors, some problem encountered due to lack of maintenance, etc.

In this project report an attempt has been made on some problem, those generally encountered in offshore pipelines remedial measures to overcome those problems. The problems generally encountered are

- Leak
- Rupture.
- Buckling Or Deformation
- Blockage Of Pipelines
- Corrosion
- Pour Point Depression.

# 3.0 DETECTION AND CAUSES OF FAILURES GENERALLY ENCOUNTERED IN OFFSHORE PIPELINE

## 3.1 LEAK

Leaks from offshore pipelines are just as frequent as pipeline leaks on lands. Further, the risk of offshore pipelines spills is some as tank vessels spills and other oil and gas transportation disasters. Such leaks can be catastrophic events, causing extensive environmental damages, human injuries or fatalities. Some time fire or explosion also occurs. Leaks may be undetectable. Small spills of 1-5 gallon/hr. from pin hole defects causes by pipeline wall defects. Some leaks may be discovered quickly, much smaller leaks can go undetected for months if

- The leak rate is small enough not to be noticed by inventory and control events.
- Ocean currents and weather disperse the oil and gas at surface.

Causes of leak ranges from external impact on offshore pipeline (vessels keels, dredges) to metallurgical defects in pipe wall.

### 3.1.1 CAUSES OF LEAK IN SUB SEA PIPELINES

There are various causes of leak in sub sea pipelines. Generally leak in Sub Sea pipelines occurred due to mechanical objects. The causes of leak are:

Leaking valves

- Joints
- Screw joints
- Threads
- Flanges:
  - (a) Missing gaskets
  - (b) Wrong type gasket
  - (c) Wrong Size Gaskets
  - (d) Corroded gaskets (due to incorrect pickling)
  - (e) Hand tight bolts
  - (f) Missing bolts

- Gasket fillings
- Pipe barrels
- Damage part of pipe by corrosion
- Drop objects: objects dropped overboard have included skirt piles, bundles of pipe and material or equipment during off-loading, boat landings during installation, and pile driving adapter caps.

## 3.1.2 LOCATION OF LEAKS

- Valves
- Gaskets
- Valve joints
- Pipe barrels

## 3.1.3 LEAK DETECTION TECHNOLOGIES

Leak detection technologies can be categorized in two parts:

(i) Hardware Based Methods And

(ii) Software Based Methods.

Hardware based methods are those methods that requires special sensors, equipments while software based methods make use of routine pressure, temperature and flow rate information. Software based methods uses special purpose software. Most offshore pipeline companies uses this method. Because this method require less men power, but this method needs accurate monitoring of pipeline. These software measures pressure, temperature of flow to detect leak.

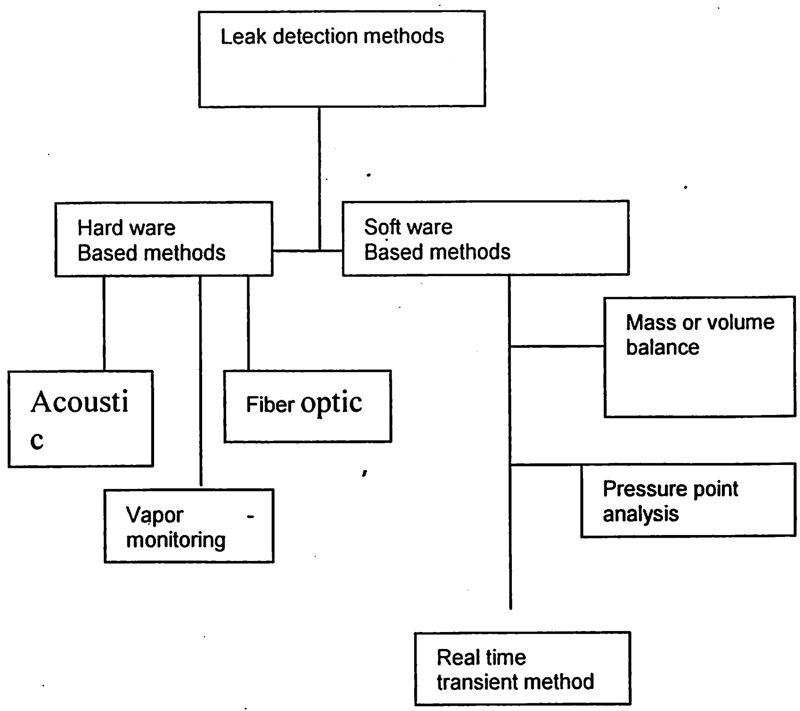



*Fig 3 CATEGORIZATION OF LEAK DETECTION TECHNOLOGY*

## 3.1.4 Hardware Based Methods

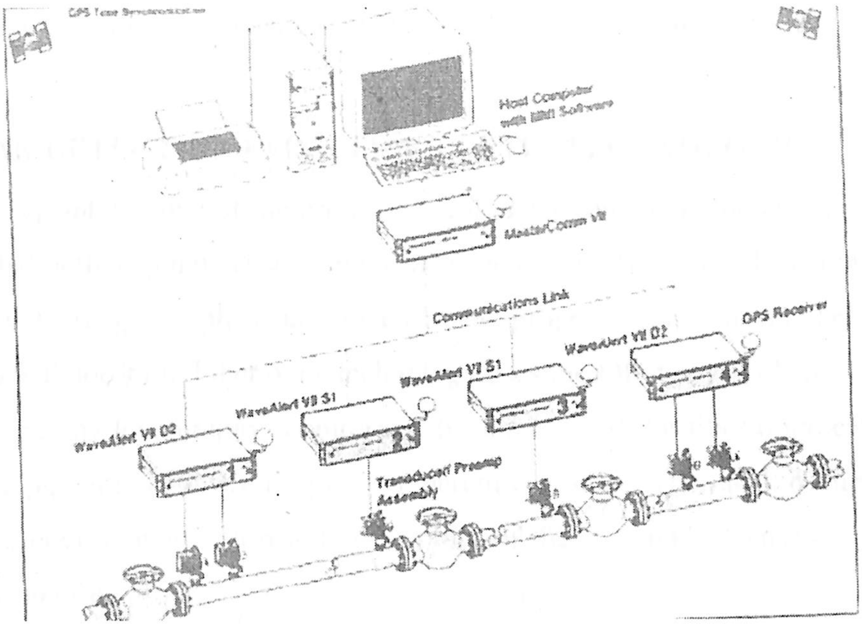
(i) Acoustic Emission methods (Acoustic devices)

(ii) Fiber optic technology (fiber optic sensors)

(iii) Vapor monitoring system

### 3.1.4.1 LEAK DETECTION IN PIPELINES USING ACOUSTIC EMISSION METHOD

**Principle:** This method uses noise (acoustic) sensors installed outside the pipeline. A leak generates a noise signal which can be picked up by these acoustic sensors. This method was used for steam boilers and later for hydro-testing of pipelines. The systems works best for high-pressure, low flow rate pipelines. For accurate leak detection, it is necessary to minimize external noise and identify pipeline operating noises.




*SOURCE: ACOUSTIC SYSTEM* INC

***. FIG4 LEAK DETECTION BY ACOUSTIC EMISSION METHOD***

Acoustic Systems Incorporated (ASI),wave alert is a real time pipeline leak detection system, which detects leak based on acoustic emission system. To detect pipeline leak, the acoustic emission technology uses the signals generated by the sudden pressure drops. The size of the leak can be estimated from the amplitude of the acoustic wave. The acoustic signal increases with the leak size.

**Components Used:**

(i) Host Computer With IJMI Software

(ii) Master Communication

(iii) Communication Link

(iv) GPS Receiver

(v) Wave Alert

(vi) Transducer Assembly

**Advantages of the Technology**

(i) Leak location in pipeline can be done using Acoustic Emission method by using interrogation techniques.

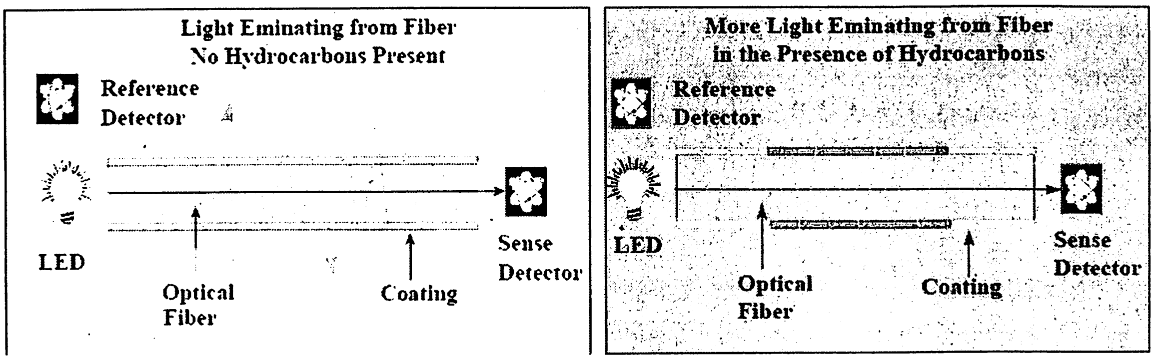
**Limitation of the Technology**

(i) For high flow rates, the background noise will mask the sound of a leak.

### 3.1.4.2 LEAK DETECTION USING FIBER OPTIC TECHNOLOGY

**Principle:** Fiber optic is one of the promising leak detection technologies. Fiber optic sensors can be installed both as point sensors and as distributed sensors. Optical fibers have the ability to detect a wide range of physical and chemical properties, which can help both in leak detection and leak location. Fiber optic technology uses the following for leak detection:

Detection of leak by temperature monitoring: In this method the fiber optic cable is installed parallel to the pipeline for measuring the temperature profile. When leak occurs, hydrocarbon escapes in the environment and results in cooling of the surrounding environment due to the Joule Thompson effect.




*SOURCE : FCI ENVIRONMENTAL INC.*

*FIG 5 LEAK DETECTION BY FIBER OPTICAL SENSING*

Detection of leak by developing micro bends: In this method when leak occurs, optical fibers develop micro bends in presence of hydrocarbons. This can be detected and located with an Optical Time Domain Reflectometer (OTDR).

**Components Used:**

(i) Reference Detector

(ii) LED

(iii) Optical Fiber

(iv) Coating

(v) Sensors

**Advantage of the Technology**

(i) This technology can be used as a distributed sensor and is non metallic in nature.

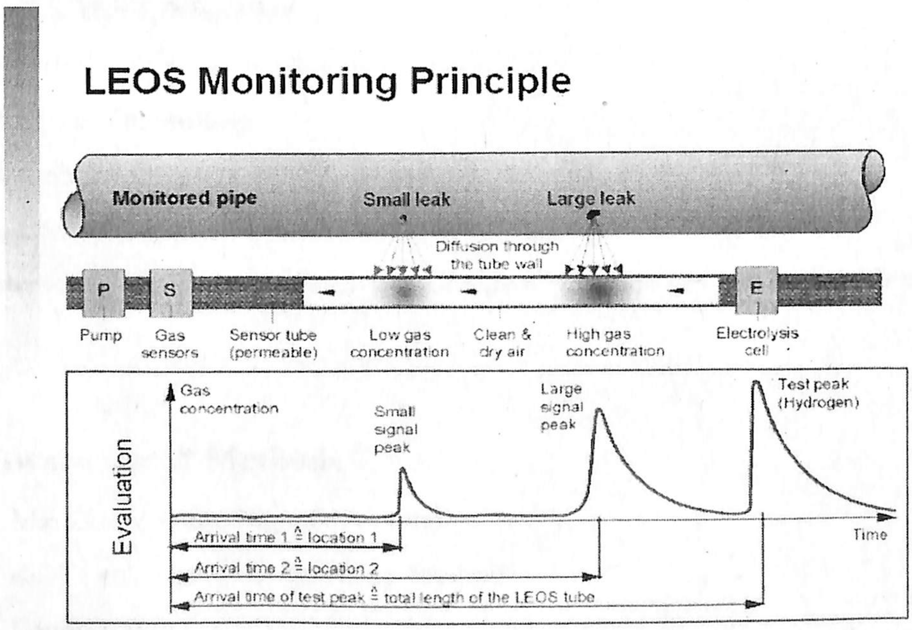
(ii) On development, fiber optic technology can offer advantage for sub Sea leak detection

**Limitation of the Technology**

(i) As of now, there has been limited commercial use of this technology for leak detection

### 3.1.4.3 LEAK DETECTION USING VAPOR-MONITORING SYSTEM

**Principle:** This system detects leak by placing a sensor tube parallel to the pipeline. In the event of leak, hydrocarbon vapors will diffuse into the sensor tube. The sensor tube is periodically pumped to the base station where the air in the tube passes through a hydrocarbon detector. The main advantage of the system is that it is a physical method of leak detection and is not dependent on pressure or volume monitoring. This system can detect small leaks which may not be detected by software base methods. This leak detection system needs higher capital investment, however does not require a lot of maintenance. The detection system is installed at the base station. Only the sensor tube needs to be installed along the pipeline, but the detector system can be located in an accessible location.




*SOURCE: SIEMENS (LEOS)*

*FIG 6 LEAK DETECTION BY VAPOR MONITORING SYSTEM*

One of the drawbacks of this leak detection system is its slow response time for detection. The response time is dependent on the pumping rate through the sensor tube. This system is therefore designed for low-level leak detection but not for rapid response. It should be coupled with another leak detection system for faster response of leak detection.

LEOS developed by Siemens is an external vapor monitoring leak detection system. It detects leaks using a low-density polyethylene (LDPE) sensor tube.

**Components Used:**

(i) Monitored Pipe

(ii) Pump

(iii) Gas Sensors

(iv) Sensor Tubes

(v) Electrolysis Cell

**Advantage of the Technology**

(i) This system can detect small leaks, which are not detectable by conventional leak detection methods based on pressure or flow balance.

**Application to Offshore/Deepwater**

(i) This system has been used in shallow water depth.

**Application to Multiphase Flow**

(i) The system can detect leaks in multiphase flow.

**Limitation of the Technology**

(i) The time for detection of leaks is dependent on pumping rate.

(ii) The cost of detection of leaks can be very high.

(iii) System may not be very effective for deepwater, as the gas can be soluble at that depth.

### 3.1.5 Software Based Methods

(i) Mass Or Volume Balance Methods

(ii) Real Time Transient modeling Method

(iii) Pressure Point Analysis

### 3.1.5.1 LEAK DETECTION USING MASS BALANCE METHOD

**Principle:** The mass balance technique is based on the principle of conservation of mass. For a pipeline the flow entering and leaving the pipe can be measured. The mass of the fluid can be estimated from the dimensions of the pipe and by measuring process variables like volumetric flow rate, pressure and temperature. When the mass of the fluid exiting from the pipe section is less than estimated mass, a leak is determined.

The pressure is used for determining the line packing. This is the most widespread technique currently in use. This technique requires high accuracy of the instruments measuring flow, pressure and temperature variables. This software requires the flow variable to be converted into mass flow rate or standard volumetric flow rate. Enviropipe Applications Inc. has a leak detection system based on the above method.

**Components Used:**

(i) Computer System

(ii) Software

(iii) Some Process Variable Such As Volumetric Flow Rate, Pressure, temperature.

**Advantage of the Technology**

(i) It is commercially available and has been used on oil pipelines. This is the most widely used method for leak detection.

(ii) Mass balance method is a software system relying on the existing pipeline instrumentation and SCADA system. Hence there are no costs associated with data acquisition and extra instrumentation

(iii) Unlike transient models, it does not rely on detailed pipeline simulation Hence it does not require long hours of tuning and controller training.

**Application to Offshore/Deepwater**

(i) It has been successfully applied in both arctic and underwater environments.

**Application to Multiphase Flow**

(i) There is no available multiphase flow leak detection capability with this technology.

**Limitation of the Technology**

(i) The Mass Balance system responds to the leak only after the pressure waves corresponding to the leak have traveled to both ends of the line. Depending on the size of the leak this may take a long time.

### 3.1.5.2 LEAK DETECTION USING REAL TIME TRANSIENT METHOD (RTTM)

**Principle:** The Real Time Transient Method (RTTM) for leak detection uses mass, momentum, energy, and equation of state algorithms for determining the flow rates. The difference between the predicted and measured values of the flow variable is used to determine leak in the pipeline. This technology requires measurement of flow, pressure and temperature variables along with use of above algorithms. RTTM is continuously analyzing noise level and normal transient events to minimize false alarms. Leak thresholds are adjusted based on statistical variations in flow. Simulations Inc has a leak detection system based on Real Time Transient Method.

**Components Used:**

(i) Computer Software

(ii) False Alarm

**Advantage of the Technology:**

(i) It can compensate for monitoring during packing and unpacking of the line.

(ii) It can minimize false alarms by adjusting alarm thresholds according to current Operating conditions.

(iii) It can detect leaks of less than 1 percent of flow.

**Application to Offshore/Deepwater**

(i) It has been successfully applied in underwater environments.

**Application to Multiphase Flow**

(i) It reportedly operates sufficiently well under multiphase flow conditions.

**Application to Arctic**

(i) It has been successfully applied in cold climate.

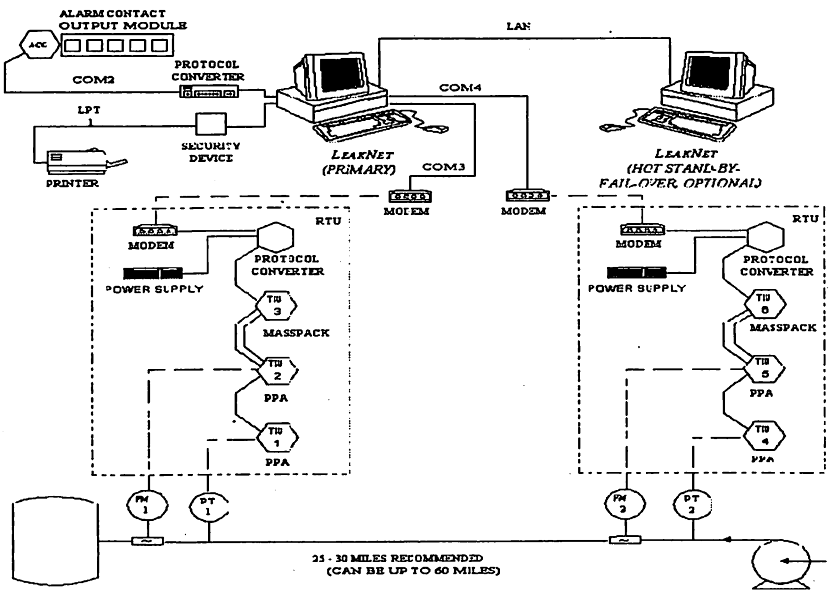
**Limitation of the Technology**

(i) Real Time Transient Method is a very expensive technology. It requires extensive instrumentation for real-time data collection.

(iii) Models are complex and require a trained user.

### 3.1.5.3 LEAK DETECTION BY PRESSURE POINT ANALYSIS

**Principle:** Pressure point analysis is an EPA-approved, patented leak detection technology. The Pressure Point Analysis Is based on the premise that the statistical property of series of pressure a measurement taken on a pipeline are different before and after a leak occurs. The pressure Point Analysis detects leak by comparing current pressure signals with the trend at a point along the pipeline. Proprietary software determines if the behavior of these two signals contains an evidence of leak.




*SOURCE: EFA TECHNOLOGIES INC*

***FIG.7 LEAK DETECTION BY PRESSURE POINT ANALYSIS***

**Components Used:**

(i) Computer System

(ii) Alarm Contact Output Module

(iii) Protocol Converter

(iv) Security Device

(v) Printer

(vi) LAN

(vii) Modem

(viii) Power Supply

**Advantage of the Technology**

(i) It has been a proven technology for arctic environment, sub sea pipelines and Multiphase application.

(ii) Software incorporating two independent methods, Pressure Point Analysis and Mass balance method are being combined to give a more effective leak detection system.

**Application to Offshore/Deepwater**

(i) It has been successfully applied in underwater environments.

**Application to Multiphase Flow**

(i) It operates sufficiently well under multiphase flow conditions.

**Application to Arctic**

(i) It has been successfully applied in cold climate.

**Limitation of the Technology**

(i) It Is affected by batch processes where valves are opened and closed and flow are increased. These transient effects may create a time period where leak detection is not possible.

(ii) Multiphase flow will act to dampen the propagation of pressure signals and create considerable background noise due to slugging and other internal flow structures.

### 3.1.6 Emerging New Technologies in Leak Detection

(i) Artificial Neural Network

(ii) Frequency Response Method

(iii) Well Logging

(iv) Air Surveillance

(v) Satellite High Resolution Reconnaissance Photography

(vi) Intelligent Pigs

*Artificial Neural Network*: This system can detect and locate leaks down to1% of flow rates in about 100sec for pipelines carrying hazardous materials. A reference pipeline was considered for practical implementation of the package. The ability of the package to withstand spurious alarms in the event of operational transients was tested. The compressibility effect, due to

'packing' of the liquid in the pipeline, causes many such spurious alarms. Using a computer conjunction with the ANN to compensate for the operational variations and to prevent spurious alarms performed adequate preprocessing of the data.

*Frequency Response Method:* The Frequency Response Method is used to determine the location and rate of leakage in open loop piping systems. A steady-oscillatory flow, produced by the periodic opening and closing of a valve, is analyzed in the frequency domain by using Several piping systems have been successfully analyzed for all practical values of the friction factor to detect and locate individual leaks of up to 0.5% of the mean discharge.

*The Well Logging Tool* (Reservoir Saturation Tool, RST) has been used in the oil industry for more than10 years. The system measures the ratio of carbon to oxygen (COR) in the soil formation, by sensing the gamma ray emitted from neutron scattering. It has a detection range of 10 inches. The recommended arrangement is a non-PVC tube, which is more than10 inches from the pipeline.

*Air surveillance:* can be through visual observation, or through use of Side looking airborne radar, Ultraviolet (UV) and infrared (IR), forward-looking infrared (FLIR) imaging, or High-resolution Reconnaissance photography The four airborne sensors listed are not routinely used for surveillance.

*Satellite High-resolution Reconnaissance photography:* has not yet offered adequate reliability(due to cloud cover) nor the desired resolution for detecting small spills.

*Intelligent Pigs*: can use caliper logging, photographic or television logging, magnetic flux logging or ultrasonic logging to detect leaks in the pipelines. These pigs are routinely run more for prevention then detection of leaks.

### 3.1.7 DETERMINATION OF LEAK DETECTION TECHNIQUES TO BE OPTED

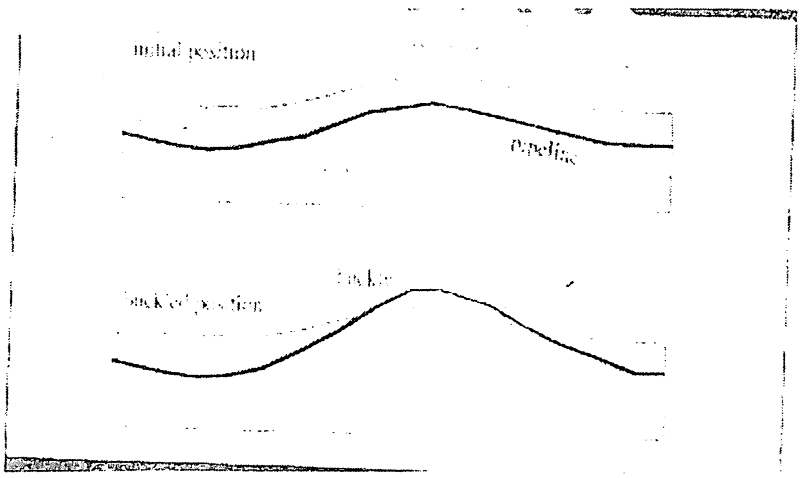
The best available technique is evaluated for each of the above applications based on the following criteria

- Can the system be used in the required application?
- Each application (sub sea/arctic/multiphase) imposes some other physical restriction for detection of leaks. Can the leak detection method work under the physical, restrictions.
- Is the leak detection method a proven technology in these applications?
- System provides the best cost-benefit.
- The system surpasses present regulatory stipulations for leak detection thresholds.
- The combined system provides low threshold detection capability.

- The combined system provides rapid response in detection and location of leaks.

## 3.2 BUCKLING

Using either S-lay or J-lay techniques, submarine pipelines have been installed all over then world, in water depths down to 2000 m and beyond, and in diameters ranging from 76mm(3") up to1270mm (50"). Both the S-lay and the J-lay methods present the risk of pipeline buckling and both employ various measures to prevent it; however, the risk of buckling can never be completely removed. Local buckling, which in its extreme form can result in the total collapse of the pipe cross section, represents one of the most severe failure modes for submarine pipelines. Submarine pipelines are generally designed in strengths grades up to X65. The reason for this limitation on strength, compared to the highest strengths available, relates to other pipeline design requirements that can mandate the provision of thicker wall than that required for pressure containment. These requirements may include on- bottom stability, resistance to buckling during installation and stress imposed during reeling. Resistance to buckling depends primarily on the pipeline diameter/wall thickness ratio(r/d) and to much lesser extent on material properties such as yield strength and elastic modulus.



*SOURCE: SUB SEA PIPELINE ENGINEERING*

***FIG 8 UPHEAVEL BUCKLING***

- The risk of buckling can be minimize by installing the pipeline partially fully flooded with sea water. Use of X80 steel would reduce suspended weight while meeting the reduced d/t ratio. The buckling can appear as a consequence of the bending moment (over the stinger or at the touch down point), of the external pressure, or as a combination of both. For deep waters and ultra deep waters, the buckling caused by the external pressure will be the governing .

Local buckling of newly laid pipelines can be caused by a variety of reasons:

- Line pipe out of specs
- Mismatch of welds
- Step changes in wall thickness
- Step changes in yield limit
- Presence of inline items such as Tees or Y-Pieces

### 3.2.1 CAUSES OF UPHEAVAL BUCKLING

A buried pipeline can sometimes arch upwards out of the seabed, forming a raised loop that may project several meters. That event is called upheaval buckling. A pipeline on the seabed can alternately snake sideways. The action is lateral buckling and can also happen if the pipeline is buried.

Most pipeline carry longitudinal compressive force induced by the operating temperature and pressure. Upheaval buckling is caused by the interaction between that longitudinal compressive forces and the local curvature of the pipeline axis. It is loosely analogous to the buckling of axially compressed columns, which is well known in structural analysis, and closely related to the buckling of axially constrained.

### 3.2.2 METHODS OF BUCKLING DETECTION; APPLICABILITY AND LIMITATIONS

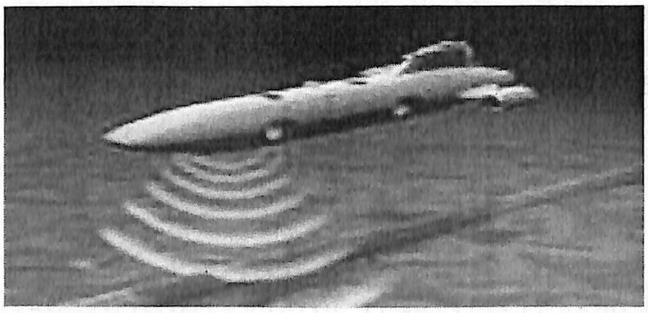
It is critical than any buckling is detected as soon as possible. Providing that the occurrence of local buckling is detected during the installation of the pipe, the repair can be carried out with relative ease. In the case of a dry buckle, the damaged section of the pipe is usually recovered back to the laying vessel, where it is removed and the installation work can restart without significant costs overruns or delays to the schedule.

In the case of a wet buckle it may be necessary to lay down the pipe on the seabed, remove the damaged section by a subsea pipe cutter, connect an emergency recovery head to the pipeline and recover the pipe to the laying vessel. In most such cases, the pipeline must be dewatered before it can be recovered. All these activities will result in significant additional costs and increased delays.

In the case of a wet buckle it may be necessary to lay down the pipe on the seabed, remove the damaged section by a subsea pipe cutter, connect an emergency recovery head to the pipeline and recover the pipe to the laying vessel. In most such cases, the pipeline must be dewatered before it can be recovered. All these activities will result in significant additional costs and increased delays.

There are several methods that can be employed to detect buckles as they occur:

- **3.2.2.1 GAUGING PLATE:** One of the most employed methods of buckling detection is to pull a gauging plate using a tension cable. This method presents several drawbacks, including: relatively low sensitivity; significant number of false alarms; increased cable weight and friction for deep pipelines. The most significant risk is that of a broken wire, the subsequent "fishing activity" to recover the plate can be a very frustrating experience with no guaranteed results and serious delays may be encountered.
- **3.2.2.2 ROV:** Where the use of an internal gauging plate is considered too risky, an ROV can be used to continuously follow and video monitor the newly laid pipe just after the touch down point.



*SOURCE: OCEAN EXPLORER*

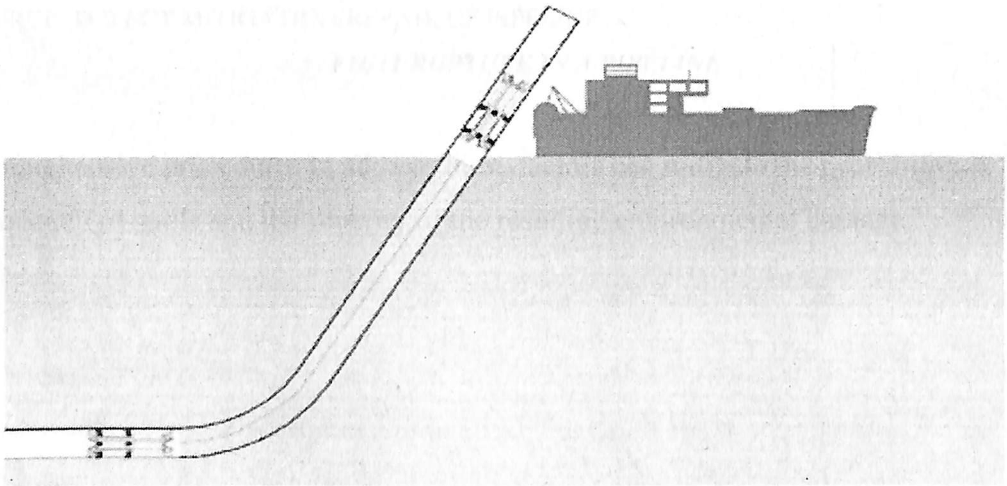
***FIG9REMOTE OPERATED VEHICLE***

- In addition to the significant additional costs related to the use of an ROV and a team of operators exclusively dedicated to this activity, this method depends on very good visibility and may not be of any use where the water is very dirty,or the pipe sinks in a soft seabed.

- **3.2.2.3 INDIRECT METHODS:** All indirect methods depend on close monitoring of operating parameters, e.g. top tension, top angle, volume of air escaping or entering the pipe at the barge end, listening to the noise generated by a propagating buckle, etc. All
- these methods have severe limitations, due to the difficulty of monitoring all necessary parameters with the required degree of precision in the operating conditions encountered on a real barge. After all, the probability of an optimally positioned laying barge operating quietly under a clear blue sky with only a gentle breeze and with no discernable undercurrents or unexpectedly large free spans must be pretty low.

### 3.2.3 A NEW APPROACH

A new method employs two tethered bristle tractors (also known as pipeline crawlers); one is located close in response to the challenges presented by the current buckle detection methods. This new method to the barge end, the other beyond the point were buckling is expected to occur.



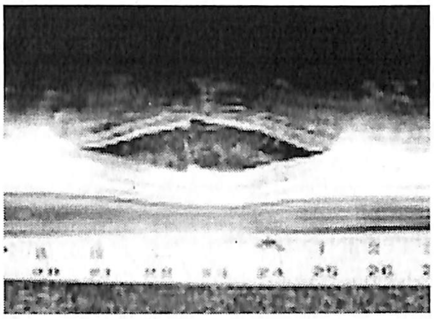
*SOURCE:* A NEW APPROACH TO BUCKLING DETECTION IN OFFSHORE PIPLINES

***FIG 10*GENERAL LAYOUT SHOWING TWO TRACTORS INSIDE A SUBMARINE PIPELINE BEINGLAID FROM A BARGE**

The two crawlers "walk" in synch along the pipe, as it is being laid. As both tractors are self- propelled, this proposed new method will remove the need to have a cable in tension. The first crawler will be fitted with a quick-disconnect umbilical. This crawler will also support the weight of the connecting umbilical that will provide the necessary power and signal cables to the second crawler. By fitting the second crawler with a camera and an array of sensors, video images and geometrical measurements of the newly laid pipe can be obtained in real time.

## 3.3 RUPTURE

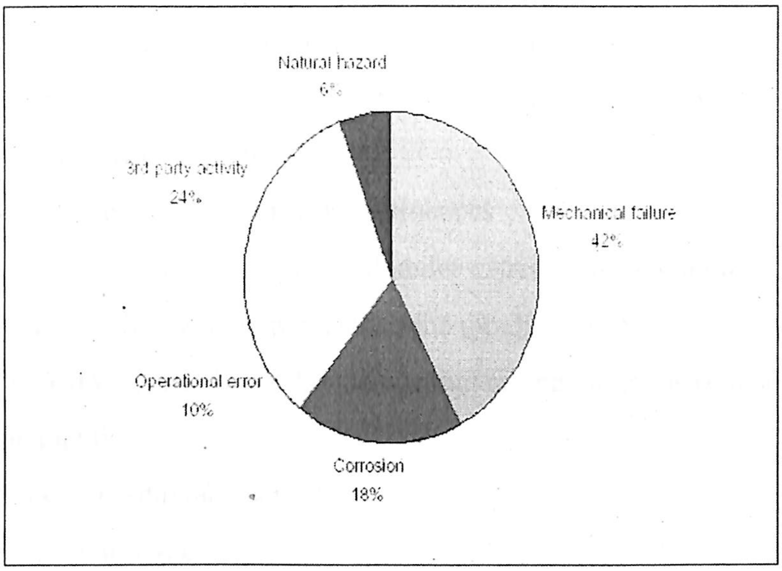
Pipeline rupture is a very slow process. Risk of pipeline ruptures is a function of several factors including mechanical problems, corrosion, third-party activities, operational variables, and climatic or environmental changes.



SOURCE: DEFECT MITIGATION/REPAIR OF PIPELINE

*FIG11 RUPTURE IN A PIPELINE*

Comprehensive procedures to address these factors can mitigate the probability or frequency of spills and the severity of the resulting environmental damage.




***SOURCE: PIPELINE OIL SPILL PREVENTION AND REMEDIATION IN FSU,DNV,1997***

***FIG: 12 DISTRIBUATION OF SPILL CAUSES FSU 1986-96***

## 3.3.1 CAUSES OF RUPTURE IN SUB SEA PIPELINE

**Sources Due To Human Activity-** there is

CATEGORY A

- Impact or hooking by ship and construction vessel anchors ranging from 20 kg to 30 tones.
- Equipment failure
- Operator error
- Military activity
- Sabotage

CATEGORY B

- Ship grounding and vessel keel
- Crossing of the other pipeline
- Interaction with trawl gear
- Abrasion due to cables
- Dropped objects such as drill collars
- Internal corrosion
- **Mechanical Failure** -can occur either during construction as a result of

negligence or the utilization of poor quality pipeline materials, or as a result of structural deterioration of the pipeline material (wear-and-tear) due to age.

- **Operational Errors-** include both system failure and human errors including lack of adequate maintenance.
- Sources Due To Environmental Influences
- Pipeline instability on the sea bed under extreme storm conditions.
- Irregular sea bed which may causes the pipeline to span over a critical distance.
- Sea bed slope instability where the actual sea bed may move resulting in sliding of the pipeline.
- Seismic or earthquake activity.
- Icebergs external corrosion.
- River flooding, wind erosion, and rapid changes in temperatures

## 3.3.2 INSPECTION OF RUPTURE

### 3.3.2.1 MAGNETIC PARTICLE INSPECTION

MPI is used to detect surface-emergent cracks. It can be applied to steel under water and it is regularly used for inspection for rupture or fatigue cracks on the structural nodes on jackets.

The pipe surface is magnetized using electrical or permanent magnets. The magnetic field is distorted at the cracks and other surface –emergent defects that are not parallel to magnetic flux. A fluid containing ferromagnetic particles is painted onto the metal surface or blown gently over the surface. This technique is used to identify lamination in the weld bevels and to detect fatigue cracks or rupture and other external cracking of pipeline in service. The main advantage of the MPI technique in the detection of fine cracks not visible to eye. However, requires a clean surface and is relative slow messy.

## 3.4 CORROSIONS IN OFFSHORE PIPELINES

Corrosion is the deterioration of materials by chemical interaction with their environment. The term corrosion is sometimes also applied to the degradation of plastics, concrete and wood, but generally refers to metals. The most widely used metal is iron (usually as steel).

Corrosion in off shore pipelines: The off shore pipelines are constructed of high strength carbon steel in several grades, depending on size, internal operating pressure, bending and longitudinal stresses expected during construction, and anticipated environmental conditions. All piping materials and fittings are specified to be consistent with industries standards, promulgated by technical societies such as the American Petroleum Institute and the American Society for mechanical Engineers.

### 3.4.1 INTERNAL CORROSION

The phenomenon of internal corrosion is well understood by the pipeline industries, but requires increasing attention as pipelines and oil and gas producing field age. In both gas and liquid lines, corrosive mixtures of foreign materials such as brine, drilling fluids, bacteria from production reservoirs, not removed by production equipments, water with hydrocarbons and other acid gases. Metal loss from internal corrosion is generally concentrated at the bottom of the pipes and at low spots, especially in gas lines because the corrosive substance tends to be heavier than oil or gas.

RELATIVE OCCURRENCE OF INTERNAL CORROSION

| Corrosion failure mechanism | Percentage |
|---|---|
| Carbon di oxide mechanism | 32 |
| Combined velocity and Carbon di oxide corrosion | 5 |
| Chemical attack | 1 |
| Combined corrosion and fabrication Defects | 3 |
| Microbiological corrosion | 13 |
| Corrosion of threaded items | 11 |
| Corrosion in dead legs | 16 |
| Erosion | 8 |
| Mechanical associated corrosion Failures | 2 |
| Corrosion fatigue | 1 |
| External corrosion | 7 |

**Table 2**

Internal corrosion process depends upon service of the pipelines .following are the four separate cases of corrosion.

- Sweet corrosion caused by the presence of carbon di oxide dissolved in the fluids; also called carbonic acid corrosion.
- Sour corrosion is caused by the hydrogen sulphide in the fluids.
- In water injection pipelines, the corrosion results either from the presence of oxygen in the water or microbiological activity of the sulphate reducing bacteria (SRB).
- Microbiological corrosion resulting from the activity and growth of the SRB in the pipelines.

### 3.4.1.1 INTERNAL CORROSION PREVENTION

The phenomenon of internal corrosion is well understood by the pipeline industry, but requires increasing attention as pipelines and oil and gas producing fields age. In both gas and liquid lines, corrosive mixtures of foreign materials such as brine, drilling fluids, and bacteria from production reservoirs, not removed by production equipment, travel in the product stream. Metal loss from internal corrosion is generally concentrated at the bottoms of the pipe and at low spots, especially in gas lines because the corrosive substances tend to be heavier than oil or gas. In some cases, a combination of erosion and corrosion can occur. As more pipelines transport mixtures of produced fluids (oil, gas, and water), corrosion problems have become more complex, but they remain manageable. The internal corrosion problem has grown more challenging in natural gas lines during the past 10 to 15 years, owing to changes in operating and economic conditions.

Today pipelines are more likely to carry such liquids to shore, because of the value of the recovered liquids and the operational efficiencies of separation ashore, as well as the limited water disposal options offshore. Cooler temperatures around the pipeline on the ocean floor cause condensation of entrained liquid vapors, including water, resulting in formation of corrosive liquids. Shifts of production to deeper waters will tend to increase condensation of many of these corrosive fluids, because pipelines will carry more mixed fluids longer distances from producing fields to treatment and separation facilities, and in cooler waters. Internal corrosion is more difficult than external corrosion to locate and quantify, owing mainly to the relative inaccessibility of intermediate sampling points on offshore pipelines. Onshore, monitoring can be performed at valve sites, stations, instrument locations, and other points, to help isolate and locate active internal corrosion. Offshore there is typically no opportunity to establish monitoring points except at the originating platform. This location is of limited use in establishing the existence of corrosion downstream. It is far more desirable to have monitoring points at both intermediate and end points of a pipeline. Even under the best of circumstances, onshore or offshore, it may be difficult to determine where fluid velocities and pipeline profiles combine to allow water to drop out of the fluid, or to cause erosion of the pipeline; the chemistry of the fluid and the nature of entrained substances all affect internal corrosion activity. Operators use various indirect means of monitoring internal corrosion.

- **CLEANING PIGS**

Hard rubber or inflatable plastic spheres or cylindrical devices that travel with the product flow—are often used to move foreign substances to a downstream location where they are removed from the system. The recovered material is analyzed to determine the adequacy of the internal corrosion control measures, including any chemical inhibitor programs in use. In many pipeline systems (mainly those with sub sea connections with other pipelines), the use of pigs is difficult or impossible. Where feasible, it is an important means of increasing the effectiveness of internal corrosion control, used by most pipeline operators. It not only removes corrosive materials and gives operators information on corrosion activity in the pipe, but also brings corrosion inhibiting chemicals in better contact with the pipe surface.

- **IN-LINE INSPECTION DEVICES**

The use of in-line inspection (ILI) devices (more commonly referred to as smart pigs) to measure various physical characteristics of pipelines has continued to gain acceptance in the pipeline industry as the technology has developed and improved. A variety of ILI devices are used to provide information to pipeline operators, such as the types and locations of pipe anomalies, the radii and locations of bends, and even photographic images. Most carry instruments to measure either ultrasonic signals or magnetic flux leakage, which indicate metal loss. They carry their own batteries, tape recorders, and odometers. ILI services are now supplied worldwide by more than a dozen companies offering more than 20 types of smart pigs. These pigs are launched from special "launch traps," propelled by the transported oil or gas, and removed through "receiver traps." Smart pigging technology has progressed significantly, and is likely to continue improving, driven by the needs of the pipeline industry.

- **LIMITATION OF ILI DEVICES**

Most smart pigging in the abroad has taken place in onshore pipeline systems, where smart pigs have earned a place among the various techniques available to operators to evaluate the long-term integrity of pipeline systems. However, the conditions of offshore pipelines are more challenging, and widespread use of smart pigs there will require substantial advances in technology.

- First, today 's smart pigs are too big (about 8 to 12 feet long) to fit the vast majority of offshore pipeline systems with their varying pipe diameters and tight bends, restrictive sub sea connections, and limited space on platforms for the needed pig launch and receiver traps. Conversion of these pipelines is rarely practical.
- As offshore oil and gas production moves into deeper waters, most new fields will rely on pipelines that tie in to the existing pipeline system, which will continue to limit smart pig use. In new and existing lines that run from platform to platform or from platform to shore with properly sized sub sea tie-ins and without sharp bends, smart pigs may be accommodated.
- The question of cost-effectiveness, though, will remain a real one. Even with marine pipelines that can accommodate smart pigs, the procedure is significantly less cost-effective offshore than onshore: The consequences of the corrosion failures and other minor leaks that could be prevented by smart pigs are smaller offshore, with no human safety or property damage impacts and generally minimal environmental impacts.
- The costs of smart pig surveys are significantly higher. Preliminary line cleaning is more difficult, and sometimes impossible, because of the heavier wax deposits that form in marine oil pipelines.

Temporary launching facilities are more difficult and costly to install offshore. On existing pipelines, indicated defect locations are harder to establish, because the temporary magnetic mile markers placed on pipelines onshore for use in calibrating distance readings are not practical offshore (where their placement would be very expensive). (On new pipelines, it is possible to improve the accuracy of flaw location, for example, by installing permanent magnetic mile markers or using accurately located weld joints as mileage calibration data.)

- **CORROSION INHIBITION**

The efficiency of inhibitor is markedly affected by the cleanliness of the pipe. Pipes containing a high level of debris (rust, mill scale, and solids from production) are more difficult to protect with inhibitors because the chemical is adsorbed onto the surfaces of the debris. This is a particular problem in sour system where very large quantities of finely divided iron sulphides are formed. At about 100ppm, the nature of the corrosion films alters from being predominantly iron carbonate to iron sulphide. Inhibitors for sour system generally contain imidazolenes.

Inhibitors are also sensitive to flow rate and flow regime. Inhibitors efficiency is reduced in low and stagnant flow conditions. In very high flow environments, the inhibitors efficiency is also affected: the inhibitors films are stripped from the metal surface by the shear force exerted by the flow. There is no typical flow rate-values of 17-20 m/s are often regarded as limits for many inhibitors, and candidate corrosion inhibitors must be tested.

Slug flow reduces the effectiveness of the corrosion inhibitors because the high shear force arising from passage of the slug remove the inhibitors film from the pipe wall.

One operator factors inhibitors efficiency in proportion to the slug frequency and assumes 90% inhibitors efficiency during periods when there are no slug and 0% inhibitor efficiency during the passage of the slugs.

Based on total fluids, typical corrosion inhibition concentrations are 5-50 ppm for continuous addition and up to 250 ppm for batch dosing. Gas inhibitors dosage rates are in the range 0.25-0.75 liter/mmscf of gas.

The effectiveness of the inhibitors is markedly affected by the concentration: therefore, the injection dosing rates must track the flow rate of fluids in the pipelines.

Inhibitor is injected into an oil pipeline fluid stream using a quill. In gas pipelines, the method of addition of the inhibitors into the fluid stream needs careful attention. Most inhibitors must be dilute and injected by atomizer can be inserted in and retrieved from the pipe through conventional 2-inch access fitting with the side entry pipe.

### 3.4.2 EXTERNAL CORROSION

#### 3.4.2.1 CORROSION MECHANISM

Corrosion is the result of the two separate reaction processes on a metal surface: the loss of the metal and production of electrons at anodic areas and the consumption of these electrons at cathodic areas. Hence the overall rate of corrosion on the pipeline external surface is dictated by ratio of anode area to cathode area, the concentration of cathodic reactant and to lesser degree, the resistivity of the local environment, which determines the rate of transport of ions between the anodic and cathodic areas. The corrosion process is the dissolution of the iron of the pipeline at anodic area as charged positive ions into the sea water or sea bed sediments. These ferrous ions react to form oxides and hydroxide and may form ferric salts if the water is well oxygenated. For the corrosion to continue, the electrons remaining on the metal surface must be removed by cathodic reaction. Typical cathodic reactions are hydrogen evolution and oxygen reduction. Because sea water has an alkaline $_pH$ of 8.2 or above, the principal cathodic reactions in sea water is oxygen reduction; and the corrosion reactions are the following:

$Fe \rightarrow Fe^{++} + 2$ electrons Anodic Reactions

$O_2 + 4H_2O + 4$ electrons $\rightarrow 4(OH)^-$ Cathodic Reaction

The overall reaction is:

$$2Fe + O_2 + 4H_2O \rightarrow 2Fe(OH)_2$$

The higher the availability of the oxygen to the metal surface, the higher the potential rate of corrosion. Oxygen access to bare metal surface increases as the temperature of the water decreases or as the flow rate over the surface increases. Pipelines are, therefore, at high risk of corrosion in cold water moving at high velocity.

Potential corrosion rates of steel in seawater

| Centralize Potential Corrosion Rate (Mm/Vv) | | | | | |
|---|---|---|---|---|---|
| Sea water velocity (m/s) | Oxygen Concentration (Ppm) | | | | |
| | 6 | 7 | 8 | 9 | 10 |
| 0 | 0.08 | 000.90 | 0.11 | 0.12 | 0.13 |
| 0.3 | 0.09 | 0.11 | 0.12 | 0.14 | 0.15 |
| 0.6 | 0.10 | 0.12 | 0.14 | 0.16 | 0.17 |
| 1 | 0.12 | 0.14 | 0.16 | 0.18 | 0.20 |
| 2 | 0.16 | 0.19 | 0.21 | 0.24 | 0.27 |

**TABLE 3**

### 3.4.2.2 PREVENTION FROM EXTERNAL CORROSION

The marine environment is generally uniform and stable with respect to corrosivity. Pipelines are protected against corrosion by bonded coatings. On larger diameter pipelines, which would otherwise float when empty or be subjected to excessive displacement by waves and currents, a concrete weight coating is added to provide stability, and incidentally some mechanical protection from objects such as anchors of small vessels. Specification for corrosion-preventive coatings and their applications and testing are available from several associations representing the pipeline industry and coatings firm. The OPS regulations for gas pipelines (49 CFR 192) follow criteria of the National Association Of Corrosion Engineers. Criteria for hazardous liquid i.e. petroleum, pipelines are less prescriptive, setting only general performance standards for internal and external corrosion control; in practice, however corrosion protection practice similar to those used for gas pipelines. To prevent the electrochemical process of external corrosion, marine pipelines are use cathodic protection system, which apply a small voltage to the pipe, either from an external power source or through the electrochemical reaction of two dissimilar metals.

### 3.4.2.2.1 CATHODIC PROTECTION OF PIPELINE

The cathodic corrosion prevention system (known as impressed current protection) used single-location, or "point-ground bed," anodes, powered by electrical rectifiers to provide protective current to the pipeline.

**PRINCIPLES OF CATHODIC PROTECTION**

Metal that has been extracted from its primary ore (metal oxides or other free radicals)

Has a natural tendency to revert to that state under the action of oxygen and water. This action is called corrosion and the most common example is the rusting of steel.

The principle of cathodic protection is in connecting an external anode to the metal to be protected and the passing of an electrical dc current so that all areas of the metal surface become cathodic and therefore do not corrode. The external anode may be a galvanic anode, where the current is a result of the potential difference between the two metals, or it may be an impressed current anode, where the current is impressed from an external dc power source. In electro-chemical terms, the electrical potential between the metal and the electrolyte solution with which it is in contact is made more negative, by the supply of negative charged electrons, to a value at which the corroding (anodic) reactions are stifled and only cathodic reactions can take place. It is assumed that the metal to be protected is carbon steel, which is the most common material used in construction. The cathodic protection of reinforcing carbon steel in reinforced concrete structures can be applied in a similar manner.

Cathodic protection can be achieved in two ways:

- By the use of galvanic (sacrificial) anodes, or
- By "impressed" current.

- **GALVANIC (SACRIFICIAL) ANODES**

Galvanic anode systems employ reactive metals as auxiliary anodes that are directly electrically connected to the steel to be protected. The difference in natural potentials between the anode and the steel, as indicated by their relative positions in the electro-chemical series, causes a positive current to flow in the electrolyte, from the anode to the steel. Thus, the whole surface of the steel becomes more negatively charged and becomes the cathode. The metals commonly used, as sacrificial anodes are aluminum, zinc and magnesium. These metals are alloyed to improve the long-term performance and dissolution characteristics.

- **IMPRESSED CURRENT**

Impressed-current systems employ inert (zero or low dissolution) anodes and use an external source of dc power (rectified ac) to impress a current from an external anode onto the cathode surface.

- **MONITORING OF CATHODIC PROTECTION SYSTEM**

ROVs are already commonly used to assess the external physical conditions of unburied pipelines. Equipped with magnetic tracking devices and controlled from the surface, these vehicles follow the pipeline, providing visual surveys of the pipeline and bottom conditions along the route. New systems to record corrosion control data using ROVs have not yet achieved widespread use, but are increasingly accepted by the pipeline industry. Conventional cathodic protection monitoring of offshore pipelines is generally conducted by measuring the pipe-to-electrolyte potential of the pipeline at easily accessible points, generally the platform riser and/or a point onshore. This technique produces data for only one or two points, so there is some difficulty in judging the protective status of the rest of the pipeline, which depends on such things as the condition of protective coatings and the integrity of anode-to-pipe connections. There are two ways to get more information, whose merits depend on specific conditions of the pipeline, such as length and depth, water clarity, type of corrosion coating, whether or not the pipe is buried, and the type of corrosion protection used: Spot monitoring of the pipeline potential is generally limited to locations where other maintenance or construction activities are being carried out by divers. The locations of such work are independent of anode locations, which are potentially more valuable monitoring points. Still, the additional information can be useful in the absence of other monitoring opportunities. Close-interval potential surveys provide a nearly continuous plot of the pipeline potential. Towed "fish" or ROVs can be used to carry the monitoring equipment.

- **ADVANTAGES AND USES OF CATHODIC PROTECTION**

The main advantage of cathodic protection over other forms of anti-corrosion treatment is that it is applied simply by maintaining a dc circuit and its effectiveness may be monitored continuously. Cathodic protection is commonly applied to a coated structure to provide corrosion control to areas where the coating may be damaged. It may be applied to existing structures to prolong their life.

Specifying the use of cathodic protection initially will avoid the need to provide a "corrosion allowance" to thin sections of structures that may be costly to fabricate. It may be used to afford security where even a small leak cannot be tolerated for reasons of safety or environment. Cathodic protection can, in principle, be applied to any metallic structure in contact with a bulk electrolyte (including concrete). In practice, its main use is to protect steel structures buried in soil or immersed in water. It cannot be used to prevent atmospheric corrosion on metals. However, it can be used to protect atmospherically exposed and buried reinforced concrete from corrosion, as the concrete itself contains sufficient moisture to act as the electrolyte.

- **PREVENTION OF CORROSION FROM COATINGS**

The purpose of the coating is to isolate the pipeline steel from the soil and sea water and to present a high resistance path between anodic and cathodic areas. To perform these functions, the coating must have complex blend of properties, among them:

- Low permeability to water and salts
- Low permeability to oxygen
- Good adhesion to the pipeline steel
- Adequate temperature stability

- Ease of application
- An acceptable unit price (since much coating is needed even for a modest pipeline)
- Flexibility to accommodated strains imposed during laying, reeling, or towing.
- Resistance to biodegradation.
- Ease of patch repairs at areas of damage.
- Non-toxicity, environmental neutrality, safety in application and handling.
- Ultraviolet stability for the period during storage.
- Resistance to cathodic disbondment.

Fewer coating system are more suitable for marine pipelines.AsphaltCoal Tar Enamel

- Fusion Bonded Epoxy (FBE)
- Cigarette Wrap Polyethylene (PE)
- Extruded thermoplastic PE and polypropylene(PP)

Elastomeric Coatings: Polychloroprene And Ethylene Propylene Diamine (EPDM)

- **ASPHALT AND COAL TAR**

Asphalt, Bitumen and coal tar enamel coatings are flooded coatings applied as a molten material to a rotating length of pipe. They are typically 5-6 mm thick, have relatively poor adhesion to steel, and are not strongly coherent. To ensure adhesion, the pipe surface must be adequately roughened during the cleaning process. These coatings are reinforced to secure greater cohesion, with a single or double layer of fiber glass matting introduced into the centre of coating during the flooding of the coating onto the pipe. Asphalt and CTE are the cheapest continuous coatings are available. Asphalt enamels will tolerate 65-75°c and CTE 70-80 °c, though it is important to verify the specification of the material.

- **POLYETHYLENE WRAPS**

Three-layer systems are based on either polyethylene or polypropylene (PP). Both systems have similar construction. A layer of FBE is applied to the steel followed by a copolymer adhesive and then a topcoat of either PE or PP. Polypropylene systems,

which are specified more often than polyethylene because of their resistance to higher temperatures, are used in sub sea applications up to 100 ° C (212°F). With the addition of appropriate stabilizers, a PP adhesive can operate at temperatures up to150 ° C(302°F), and solid PP can withstand temperatures of 130°C (266 ° F).In the design of a three-layer anti-corrosion system, one must also consider the capabilities of the fusion-bonded epoxy layer. FBE products with glass transition temperatures of 150 ° C (302° F) are now available, thereby extending the operating temperature capabilities of three layer PP systems.

- **FUSION-BONDED EPOXY**

Although FBE products were available in the early 1960s, they did not become widely used until the late 1970s. This type of coating is mill-applied, and for some companies, it is now the coating of choice for large diameter pipelines. This choice varies geographically with North America favoring FBE coatings and most of Europe favoring three layer polyolefin coatings. FBE coatings are thin and brittle and require good surface preparation. They exhibit excellent soil stress properties. Experimental studies have also indicated that surface preparation imparts compressive residual stresses to the surface of the steel, thereby reducing the susceptibility of the steel to stress corrosion cracking.

- **THERMOPLASTIC EXTRUSION COATINGS**

Thermoplastic extrusion coatings are polyethylene, or polypropylene and are moderately thick, typically 3-4mm. the pipe is coated with a primer coating of epoxy, applied by spray or fusion bonded onto a heated pipe. The adhesive is then extruded over the primer, followed by the molten thermoplastic sheath. The epoxy primer is thin coating approximately 75 microns thick. A polyethylene coating can tolerate 65°c, limited by the tolerance of the adhesive. Polypropylene coating can tolerate 105°c. These coating may be overcoated with a concrete weight coating and also suitable as uncovered coating for use of reel laid pipelines. Polyethylene and Polypropylene coatings are slippery, and, when a concrete weight coating is applied, it is necessary to provide anti slip bands to reduce risk of slippage of the concrete cover over the anti corrosion coating.

- **ELASTOMERIC COATING**

Elastomeric coatings are used for high temperature pipelines. One type of elastomer, polychloroprene is also widely used for covering risers because of its resilience to impact. On pipelines the coatings are 3-5 mm thick, and on risers they are typically 6-12mm thick. Sheet polychloroprene (also known as neoprene) or EPDM is glued onto a cleaned(end for EPDM primer coated) pipe, and the assembly then autoclaved to vulcanize the Elastomeric coatings.

Neoprene is suitable for temperature up to 105°c, while EPDM can be formulated for service up to 120°c. EPDM coating may be applied directly to the steel, but in a deep water this method may lead to untoward wastage of the cp system.

# 4.0 PROJECT WORK DETAILS

1. **PROJECT NAME:** Offshore Pipeline Problems and Remedial Measures.

2. **OBJECTIVE:** To develop maintenance strategies for various offshore pipelines being operated in India.

3. **Inputs:** various offshore pipelines being operated in India

| Sr.No | Owner | Pipeline Length(Km) | Pipe Size(Inch) | Duty/Service |
|---|---|---|---|---|
| 1 | ONGC | 3200 | 16,18,22,28,42 | Both |
| 2 | Niko Resources India | 2 | 12 | Both(High Pressure And Low Pressure Lines) |
| 3 | GSPC,Gujrat | 6 | 20 | Both |
| 4 | BGEPIL | 80 | 18 | Natural gas |
| 5. | Cairns Energy Ltd India | 2 | 16 | Both |

**Table 4**

The major four problems encountered on the offshore pipeline are:

1. Leak
2. Buckling
3. Rupture
4. Corrosion

The problems could be encountered in shallow water, deep water, and inter tidal zone. The repair and maintenance techniques for the problems are depended upon the zone in which the pipeline has been laid.

- INTER TIDAL WATER: The intertidal area is the transitional region between land and sea. In general, it is covered and exposed by the tidal waters each day. The intertidal zone can be either rocky or particulate shore. Rocky shores are solid substrates and particulate shores consist of sediment particles ranging in size from clay through cobbles.
- SHALLOW WATER: The depth of shallow water is generally 200m. the various problems arises at this depth can be easily remove by trained divers.
- DEEP WATER: The deep water has been defined as water depth beyond the reach of deep diving which is generally 1200ft. in these depth all work must be accomplish remotely and without direct intervention of diver. Therefore all repair work must be accomplished using a combination of specialized tools, equipments and procedure.

**4.1 MAINTENANCE TECHNIQUES AND EQUIPMENTS REQUIRED:**

The maintenance techniques for offshore pipeline generally depends on various factors such as:

- Diameter of pipe
- Water depth
- Types of problems encountered in the pipeline
- Cost of the equipments
- Availability

**4.2 PROBLEM OF LEAK IN SUBSEA PIPELINE:** If the leak problem arises in the pipeline operating at various zone, than it is essential to replace that pipe section with new one. To repair leak problem in pipe line operating at various zone the methods are:

**4.2.1 INTERTIDAL ZONE:**

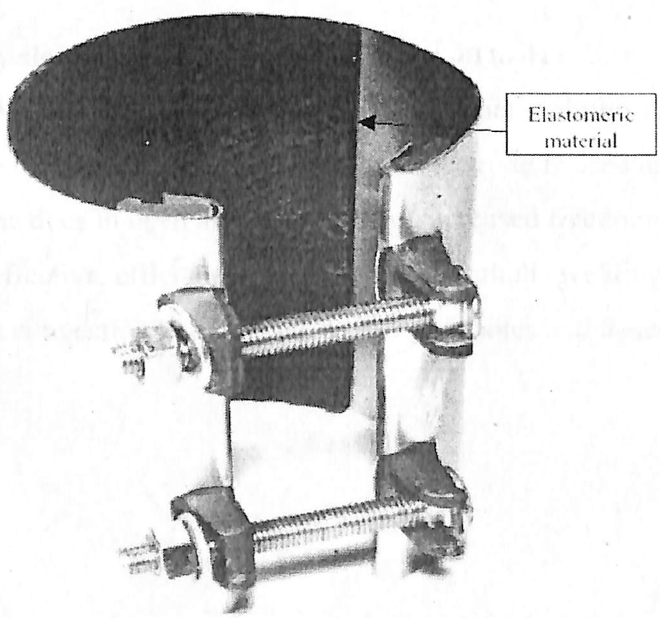
**REPAIRING METHODS:**

(1) By clamping

(2) By sleeving

(3) By welding

**BY CLAMPING:** The clamps are made of two axially hinged halves. The simplest form of repair component is a metallic patch, which may be applied to cover a small, non-leaking defect. The repair involves the welding, by fillet welding to the pipe, of a suitably curved patch. The pipe wall in the weld regions, which are away from the defect area, must be of sufficient thickness and must be defect free. This type of repair is very rarely applied to high integrity applications and offers no major advantage over a simple patch clamp -a bolted clamp that holds a patch of elastomeric material adjacent to the defect area.




*SOURCE: TEMPORARY/PERMANENT PIPE REPAIR - GUIDELINES*

*Fig no: 13 PATCH CLAMP*

**BY SLEEVING:** the full encirclement sleeves are rarely considered as alternatives to repair methods. To perform repair with sleeves, the pipeline must be completely exposed by jetting. The sleeves are spilt in half axially and held together by number of nuts. The sleeve run by guide cable and lower in to the seabed, positioned over the leak. Then by the application of the force nuts are inserted and tightened. This is the cost-effective way to repair the small leak in pipelines.

**By Welding Technique:** at the time of repairing the inter tidal zone is treated as onshore and submerged arc welding is done.

**Procedure:** At the time of welding in this zone some barricades are used to prevent entering of water. Inspection of damage pipe. The metal is joined by fusing with an electric arc or arcs struck between a bare metal wire electrode or electrodes and the pipe.the blanket of granular, fusible material spread in deep layer over the weld area shields the arcs and molten metal.

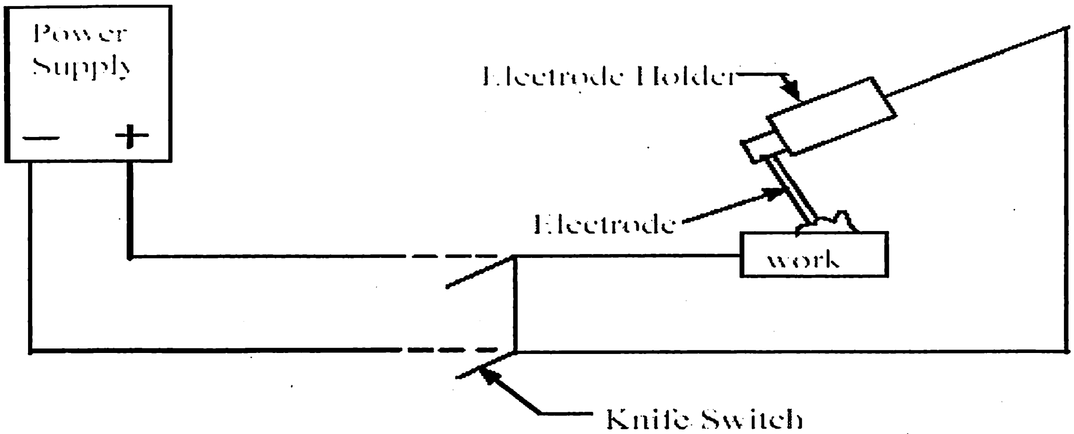
**4.2.2 SHALLOW WATER ZONE:**

**REPAIRING METHODS:**

If a pipeline has suffered from leak then there are various methods to repair the pipeline. The methods are:

**By clamping or by sleeving** (details given at page no.40 to 41)

**BY SURFACE WELDING:** Wet Welding indicates that welding is performed underwater, directly exposed to the wet environment. A special electrode is used and welding is carried out manually just as one does in open air welding. The increased freedom of movement makes wet welding the most effective, efficient and economical method. Welding power supply is located on the surface with connection to the diver/welder via cables and hoses.




***SOURCES: UNDER WATER WELDING***

***FIG NO: 14 SURFACE WELDING PROCEDURE***

This method uses various equipments and vessel. The davits are used to lift the pipe and then pipes are cut and welding is done to bridge the gap between the pipes.

1) **Procedure of welding:** pipelines are inspected and detailed plan is prepare of for repair work. The barges move to the damaged side and the damaged pipe cutting is done. a liffiting cable is attach to each pipe and then pipe ends are cut and clean. Then welding of spool pipeline is done and after coating and field joint pipes are lowered in to the sea.

**Advantages of Wet Welding**

Wet underwater MMA welding has now been widely used for many years in the repair of offshore platforms.

The benefits of wet welding are: -

2) The versatility and low cost of wet welding makes this method highly desirable.

3) Other benefits include the speed. With which the operation is carried out.

4) It is less costly compared to dry welding.

5) The welder can reach portions of offshore structures that could not be welded using other methods.

6) No enclosures are needed and no time is lost building. Readily available standard welding machine and equipments are used. The equipment needed for mobilization of a wet welded job is minimal.

**Disadvantages of Wet Welding**

Although wet welding is widely used for underwater fabrication works, it suffers from the following drawbacks: -

- There is rapid quenching of the weld metal by the surrounding water. Although quenching increases the tensile strength of the weld, it decreases the ductility and impact strength of the weldment and increases porosity and hardness.
- **Hydrogen Embrittlement** - Large amount of hydrogen is present in the weld region, resulting from the dissociation of the water vapour in the arc region. The $H_2$ dissolves in the Heat Affected Zone (HAZ) and the weld metal, which causes Embrittlement, cracks and microscopic fissures. Cracks can grow and may result in catastrophic failure of the structure.
- Another disadvantage is poor visibility. The welder some times is not able to weld properly.

**4.2.3 DEEP WATER:**

- **Mechanical connectors:** The mechanical connectors used for pipeline repair work. The system includes some means of attachment to the pipeline ends, provision for axial length adjustment. The mechanical connectors uses surface vessels with mooring capabilities, diving support and diving support equipments, surface pipe welding facilities, a lifting carne,bottom manipulating equipments.

  **PROCEDURE:** survey of damage section. Then surface vessel will towards the damage pipeline section. The damage section will cut, lifting clamps will be attached to the each section of pipe. The pipe ends will be lifted and coating will be removed then connector halves will be placed on pipe. The desired length pipe will be fabricated and the piece will lowered Into the sea with matting halves. The hydrostatic test will conduct on the pipeline to check the integrity of pipeline.

- **Hyper baric Welding (dry welding)**

  Hyperbaric welding is carried out in chamber sealed around the structure to be welded. The chamber is filled with a gas (commonly helium containing 0.5 bar of oxygen) at the prevailing pressure. The habitat is sealed onto the pipeline and filled with a breathable mixture of helium and oxygen, at or slightly above the ambient pressure at which the welding is to take place. This method produces high-quality weld joints that meet X- ray and code requirements. The gas tungsten arc welding process is employed for this process.

The area under the floor of the Habitat is open to water. Thus the welding is done in the dry but at the hydrostatic pressure of the seawater surrounding the Habitat.

**Welding procedure:** Survey of damage pipeline. The surface vessels will move to the site with mooring facilities. The damaged section will cut and the alignment frame will be lower and position it over the first pipe end to be welded. Align pipe ends to be joined and hold them in position. Now the welding habitat and place it on top of the alignment frame and over the pipe ends to be connected. Divers used as welders will enter the habitat and welding will take place in dry environment. The procedure will repeat for other pipe and appropriate coating will apply.

**Advantages of Dry Welding**

- **Welder/Diver Safety** - Welding is performed in a chamber, immune to ocean currents and marine animals. The warm, dry habitat is well illuminated and has its own environmental control system (ECS).
- **Good Quality Welds** - This method has ability to produce welds of quality comparable to open air welds because water is no longer present to quench the weld and $H_2$ level is much lower than wet welds.
- **Surface Monitoring** - Joint preparation, pipe alignment, NDT inspection, etc. are monitored visually.
- **Non-Destructive Testing (NDT)** - NDT is also facilitated by the dry habitat environment.

**Disadvantages of Dry Welding**

- The habitat welding requires large quantities of complex equipment and much support equipment on the surface. The chamber is extremely complex.
- Cost of habitat welding is extremely high and increases with depth. Work depth has an effect on habitat welding. At greater depths, the arc constricts and corresponding higher voltages are required.
- The process is costly - An $ 80000 charge for a single weld job. One cannot use the same chamber for another job, if it is a different one.

## 4.3 CORROSION IN SUB SEA PIPELINE:

### 4.3.1 INTERTIDAL ZONE:

**REPAIR METHODS:**

pipe suffering corrosion problem in the intertidal zone can be replaced either by welding technique or by using mechanical connectors.

**(1) By Welding Technique:** at the time of repairing the inter tidal zone is treated asonshore and submerged arc welding is done.

**Procedure:** At the time of welding in this zone some barricades are used to prevent entering of water. Inspection of damage pipe. The metal is joined by fusing with an electric arc or arcs struck between a bare metal wire electrode or electrodes and the pipe.the blanket of granular, fusible material spread in deep layer over the weld area shields the arcs and molten metal.

**(2) Mechanical Connectors: Mechanical connectors:** The mechanical connectors used for pipeline repair work. The system includes some means of attachment to the pipeline ends, provision for axial length adjustment. The mechanical connectors uses surface vessels with mooring capabilities, diving support and diving support equipments, surface pipe welding facilities, a lifting carne,bottom manipulating equipments.

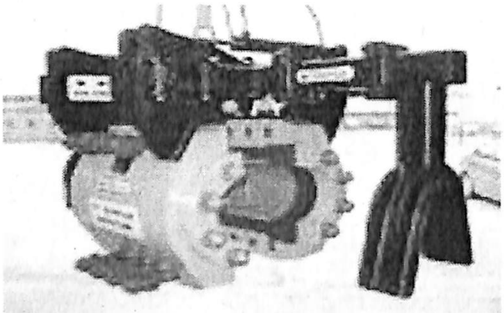


*FIG:15 MECHANICAL CONNECTORS*

**PROCEDURE:** survey of damage section. Then surface vessel will towards the damage pipeline section. The damage section will cut, lifting clamps will be attached to the each section of pipe. The pipe ends will be lifted and coating will be removed then connector halves will be placed on pipe. The desired length pipe will be fabricated and the piece will lowered Into the sea with matting halves. The hydrostatic test will conduct on the pipeline to check the integrity of pipeline.

### 4.3.2 SHALLOW WATER ZONE:

**REPAIR METHODS:**

The pipe suffering corrosion problem will essentially need affected pipe portion to be cut and replaced with new section of pipe. This can be done either by:

(1) By using welding *(details given at page no.41 )*

*(2)* Using mechanical connectors *(details given at page no.45)*

### 4.3.3 DEEP WATER ZONE:

**REPAIR METHODS:**

Pipe suffering corrosion problems will essentially need affected pipe portion to be cut and replace with new section of pipe. This can be achieved by:

1) Using welding technique (deta*ils given at page no.43)*

2) Or by using mechanical connectors (*details given at page no.45)*

## 4.4 RUPTURE IN SUB SEA PIPELINE:

### 4.4.1 INTERTIDAL ZONE:

Pipeline rupture is a very slow process. Risk of pipeline ruptures is a function of several factors including mechanical problems, corrosion, third-party activities, operational variables, and climatic or environmental changes.

**Repair methods**: pipe cutting and replacement is done either by welding technique or by using mechanical connectors.

**(1)WELDING TECHNIQUE**: (*the repair measures to be adopted as per details given at page41 ).*

**(2)BY MECHANICAL CONNECTORS:** *(the repair measures to be adopted as per details given at page 43)*

### 4.4.2 SHALLOW WATER ZONE:

**REPAIR METHODS:**

pipe suffering rupture problem will essentially need affected pipe portion to be cut and replace that pipe section with new section. This task can be achieved either by

(1) Pipe cutting / Replacement by welding

(2) Pipe cutting/ replacement using mechanical connectors.

(1) Pipe cutting/replacement by welding technique: There are various under water welding techniques such as:

- Hyper baric welding
- Surface welding

But for shallow water depth the surface welding technique is opted. (*The details given at page41)*

(2) PIPE Cutting/Replacement Using Mechanical Connectors.( *The details given at page43*)

### 4.4.3 DEEP WATER ZONE:

**REPAIR METHODS:**

The pipeline suffering from rupture problem will needed immediate remedial action. This can be achieved by two techniques

(1) By welding techniques(*The details given at page43*)

(2) By mechanical connectors(*The details given at 43)*

## 4.5 BUCKLE IN SUB SEA PIPELINE:

### 4.5.1 INTERTIDAL ZONE

**REPAIR METHODS:**

Pipe suffering buckle problem will essentially need affected pipe section to be cut and replace with new section of pipe. This task is achieved by

(1) By welding techniques

(2) By mechanical connectors.

**BY WELDING TECHNIQUE:** the submerged arc welding is done to replace the damage section of pipe. *(the repair measures to be adopted as per details given at page 41)*

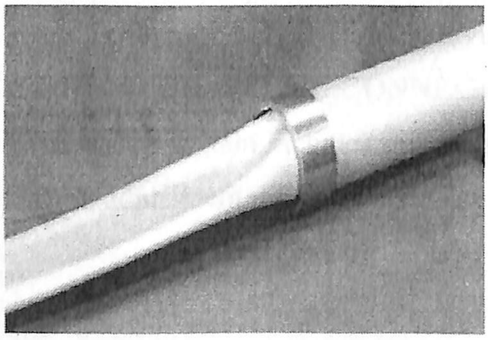
**BY MECHANICAL CONNECTORS:** the pipe ends are cut and cleaned and flange connectors are lowered and forged to pipe ends. Spool piece with joints are made and lowered. Flanges on ends connectors and spool are lined up. Bolts are inserted and tightened. (*The repair measures to be adopted as per details given at page 43)*

### 4.5.2 SHALLOW WATER ZONE:

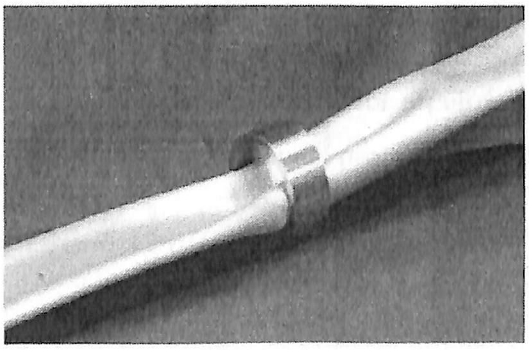
**REPAIR METHODS:**

**PREVENTION FROM BUCKLING:**

An effective way to ensure that collapse, should it occur, affects only a small length of the pipeline, is the periodic placement of buckle arrestors along the line. Buckle arrestors are devices which locally strengthen an offshore pipelin and safeguard it against the catastrophic effects of a potential propagating buckle. The size and type of buckle arrestor ring depends upon technical and economic consideration.



*(a)*



*(b)*

*SOURCE: DYNAMIC ARREST OF PROPAGATING BUCKLES*

*FIG: 16 BUCKLE ARRESTOR*

Normally a welded arrestor is better than the grouted arrestor; however grouted arrestor would be appropriate if the jump through pressure exceed the external water pressure, i.e. for case of very shallow water depth. Buckle arrestors are devices, which locally increase the circumferential bending rigidity of the pipe and thus provide an obstacle in the path of a propagating buckle. They are usually thick-walled rings that are grouted onto the pipe (*slip-on* arrestors), welded between two sections of pipe (*integral* arrestors) or slip-fit into the outer pipe in pipe- in-pipe systems (*internal ring* arrestors).

**REPAIRING METHODS:** If the buckle problems arise in the pipe than this is essential to cut that particular section of pipe and replace that section with new section. This can be achieved by:

(1) By using welding technique *(details given at page no.41)*

(2) Using mechanical connectors *(details given at page no.43)*

### 4.5.3 DEEP WATER ZONE:

**REPAIR METHODS:**

pipe suffering buckle problem will essentially need affected pipe portion to be cut and replace with new section of pipe. This task can be achieved by

(1) Using welding techniques

(2) Using mechanical connectors

**(1) REPLACEMENT OF PIPE BY WELDING TECHNIQUE:** Hyperbaric welding is undertaken in dry atmosphere but at a pressure equal to hydrostatic head at the depth of weld. Hyperbaric welding is almost invariably carried by divers trained as welders, as most hyperbaric is done by using saturation diving techniques. (*The details given at page43).*

**(2) USING MECHANICAL CONNECTORS:** The mechanical connectors used for pipeline repair work. The system includes some means of attachment to the pipeline ends, provision for axial length adjustment. (*The details given at page43*)

## 4.6 MATERIALS AND EQUIPMENTS NEEDED:

- **EQUIPMENT NEEDED FOR DEEP WATER ZONE:**

1) Surface vessels with mooring capabilities,
2) Diving support and diving support equipments,
3) Surface pipe welding facilities,
4) A lifting carne,
5) Bottom manipulating equipments.

- **EQUIPMENT NEEDED FOR SHALLOW WATER ZONE**

1) Surface equipments i.e. Lay barge with mooring facilities
2) Special equipments i.e. Barge davits
3) Lifting machine
4) Welding consumables
5) X ray machine to inspect weld
6) Coating and coating equipments

**MATERIAL NEEDED:**

1) Sleevs
2) Mechanical connectors
3) Clamps
4) Bare wire with consumable electrodes
5) Support and contact tube for electrodes
6) Pipes of appropriate length.
7) Repair couplings.
8) Welding rods.

**MEN POWER NEEDED:**

1) Trained welders
2) Crewmembers
3) Divers

## 4.7 DIVERS AND DIVING EQUIPMENTS REQUIRED:

Divers, including those on standby, must have a certificate of training from a recognized diving school or certified record of past diving experience. Prior to commencing diving operations, submit divers' names and qualifications to the COR or Dive Master. To perform repair operation in shallow water and in deep water the specially trained divers are required. These divers trained as welders to perform the welding operation in to seabed. These divers are less with various equipments to perform sub sea repair work. Diving equipments used to day is generally divided in to two classes: surface-supplied and self-contained equipments. The surface supplied is further divided in to deep sea and light weight equipment.

- **EQUIPMENT.** Use a tagging or logging system to record equipment modification, repair, test, calibration, or maintenance services. Include the date and type of work performed and the name or initials of the person who did the work.
- **Air Compressor System.** Compressors that supply air to the surface-supplied air (SSA) diver must have a volume cylinder with a check valve on the inlet side, a pressure gauge, a relief valve, a drain valve, and a carbon monoxide filter and alarm system. Compressors must have the capacity to overcome any line loss or other losses and deliver a minimum of 4.5 cubic feet per minute to each diver at the maximum working depth. Locate air compressor intakes away from areas containing exhaust or other contaminants.

  Respirable air supplied to a diver, or to air tanks, must not contain:

  1. Carbon monoxide (CO) greater than 10 parts per million (ppm).
  2. Carbon dioxide ($CO_2$) greater than 1,000 ppm.
  3. Oil mist greater than 5 milligrams per cubic meter.
  4. A noxious or strong odor.

  Test the air compressor system output for air purity at least every 6 months, by taking samples at the connection to the distribution system.

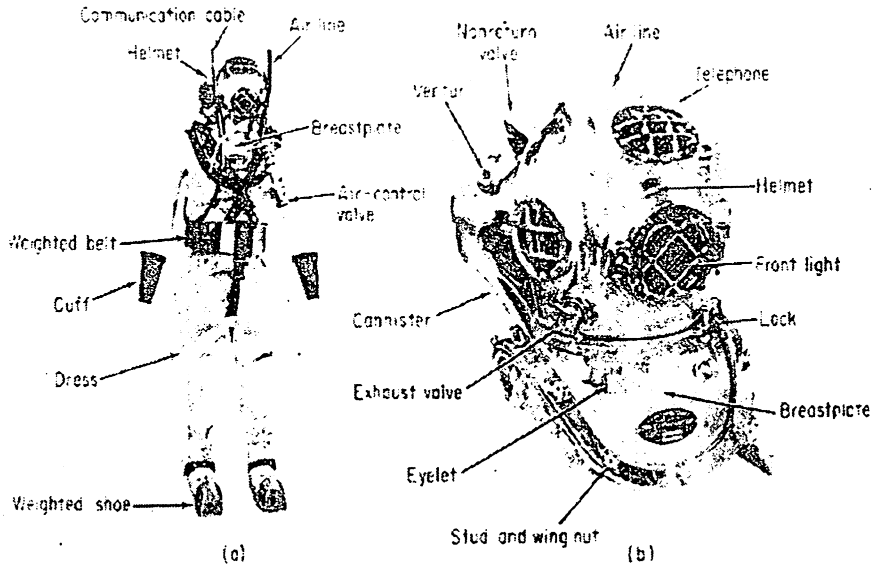



*FIG NO:17 VARIOUS DIVING EQUIMENTS*

- **Compressed Gas Cylinders.** Compressed gas cylinders must:
    1. Be designed and maintained according to the applicable provisions of 29 CFR 1910.101(a).
    2. Be stored in a ventilated area and protected from excessive heat.
    3. Be secured against falling.
    4. Have shutoff valves recessed into the cylinder or protected by a cap, except when in use, when manifold, or when used for diving.

**4.7.1 Surface-Supplied Air Diving**

- **Auxiliary Air Supply.** Provide an auxiliary air supply during all dives. The auxiliary air supply must have a standby compressor or air flasks with a capacity of 72 cubic feet or more. Compressors that are used for diving operations must not be used for any other purpose. Auxiliary air supply must meet the requirements in the subsection, "Air Compressor System."
- **Decompression.** A recognized decompression specialist must prepare decompression tables. Post decompression times inside and outside decompression chambers.
- **Decompression Chamber.** The following circumstances require an onsite, dual-lock, multiplace decompression chamber (capable of recompressing the diver to a minimum of 165 feet seawater equivalent) and trained operating personnel:

Diving operations that are outside the no-decompression limits or to depths greater than 100 feet seawater When surface recompressing capabilities are recommended by the decompression specialists, Dive Master, or where necessitated by onsite conditions Decompression chambers must accommodate at least two persons.

- **Decompression Dives.** Divers engaged in dives outside no-decompression limits or engaged in mixed-gas diving must remain awake and close to an attended decompression chamber for at least 1 hour following the dive. The diver must be able to contact a decompression chamber facility during the 4-hour period immediately following treatment or after leaving the water.
- **Communications.** Equip divers and standby divers with communication systems that permit simultaneous, two-way conversations between the diver, his tender, other divers and tenders, and the Dive Master. Communication systems must be operable from the time the diver puts on his helmet or mask until it is removed.
- **Minimum Crew Size.** Two divers must be available on any one diving operation. The standby diver must be available, suited up, and ready to dive in an emergency. The standby diver must not serve as a tender. The minimum crew must consist of at least four persons: the Dive Master, a diver, a standby diver, and a tender. For each diver added to the crew, one tender must also be added.
- **Reserve Breathing Gas Supply.** Each diver using lightweight SSA must carry a reserve breathing gas tank. When heavy, deep-sea diving gear are used, when diving to depths exceeding 100 feet of seawater, or when diving outside the no-decompression limits, the standby diver must have an extra breathing gas hose for the working diver.

### 4.7.2 Scuba Diving

- **Requirement.** Scuba diving is permitted only when sanctioned by the contract specifications and authorized in writing by the contracting officer.
- **Maximum Depths.** Limit scuba diving to depths and times that will not require decompression staging as set forth in the U.S. Navy Standard Air Decompression Tables. Scuba dives depths must not exceed 100 feet of seawater after altitude adjustment.
- **Compressed Air.** Oxygen or mixed gases are prohibited, except for up to 40 percent nitrox, when used in accordance with the National Oceanic and Atmospheric Administration (NOAA) Diving Manual: *Diving for Science and Technology,*

Chapter 15, "Nitrox Diving" and Appendix VII, "Nitrox Dive Tables." Use only open circuit scuba systems.

- **Diving Equipment.** A recognized approving agency must approve scuba diving equipment. Use and maintain scuba diving equipment in accordance with the manufacturer's recommendations.
- **Buddy System.** A dive may be made singly if the dive is less than 20 feet deep, there is little current, and visibility is good (at the discretion of the Dive Master). All other diver with scuba gear must use a buddy system.
- **Standby Diver.** Provide a standby diver for each diver or buddy pair. The standby diver must be a qualified, fully equipped scuba diver and remain on the surface, close to the diver.
- **Standard Equipment.** Scuba divers must wear buoyancy compensators and have a depth indicating device, timing device, cutting tool, compass, submersible pressure gauge (or integrated dive computer) to monitor cylinder/system air pressure, and an alternate second stage air source, such as an octopus or safe second

## 4.8 COMPARISON OF VARIOUS REPAIR MAETHODS:

| Methods/item | Surface welding | Hyperbaric welding | Mechanical connectors |
|---|---|---|---|
| Surface equipments | Lay barge | MSV or Lay barge | Boat or work barge |
| Special equipments | Brage davits | Alignment frame, welding habitat | Depends on manufacturer |
| Weather sensitivity | High | Moderate | low |
| Limitations | Suitable for shallow water | Good for 1000ft and more | Good for 42"diameters. And divers capabilities |
| Advantages | High quality weld | Welded repair | The process is fast and very economical |
| Disadvantages | Reduce arc visibility.<br>High level of porosity in weld ment.<br>Lack of fusion.<br>High quench rates. | Most expensive and very slow process | Must stock connectors of correct size. |

**TABLE 5**

## 4.9 DESIGN DATA:

The design data presented in the following sections will be utilized in the pipeline allowable free span design of the proposed 28" diameter.

**PIPELINE DATA**

- Design Life : 40 years
- Pipe line Specification
  - Outside Diameter : 28" (711.2 mm)
  - Wall Thickness : 12.7 mm (refer table1)
  - Material Grade X-65,code DNV 1991,BOSS 76
  - Internal Corrosion Allowance : 0 mm
  - Steel Density : 7850 kg/m$^3$
  - Young's Modulus : 1.937 x 10$^5$ MPa
  - Poisson's Ratio : 0.3
  - Thermal Expansion Coefficient : 11.7 x 10$^{-6}$ /°C
  - Specified Minimum Yield Strength : 450 MPa
  - Specified Minimum Tensile Strength: 535 Mpa
  - Internal pressure : 116 kgf/cm$^2$
  - External pressure : 145 kgf/cm$^2$
  - Design temperature ($T_2$) : 66.6$^0$c
  - Installation temperature ($T_1$) : 26.6$^0$c

Wall Thickness

| **Diameter in inch (mm)** | **GRADE** | **W.T. Inch (mm)** | **SMYS Mpa** |
|---|---|---|---|
| 28" (711.2) | X65 | 0.500 (12.70) | 450 |
| 28" (711.2) | X70 | 0.437 (11.1) | 482 |

| | | | |
|---|---|---|---|
| 28" (711.2) | X80 | 0.39<br>(10) | 551 |

**Table 6**

- External Corrosion Protection Coating
  - Type : Three Layer Polyethylene
  - Nominal Thickness : 0.082" (2.10 mm)
  - Density : 950 kg/m$^3$

- Internal Coating
  - Type : Epoxy
  - Nominal Thickness : 0.082" (2.10 mm)

The internal coating shall be suitable for continuous service at 150°F (66°C). The coating will be shop-applied to all pipes, with a 100 mm cut back at each end of the pipes to accommodate field joint welding.

- Concrete Weight Coating
  - Type : Reinforced Concrete
  - Thickness : 0.098" (2.5mm)
  - Density : 2250 kg/m$^3$
  - Water Absorption (max) : 5%
  - Water Density : 1025 kg/m$^3$

- Field Joint Coating
  - Type : Mastic
  - Thickness : 0.098" (2.5mm)
  - Density (in air) : 2250 kg/m$^3$

### 4.9.1 BUCKLE INITIATION

The actual minimum wall thickness for buckle initiation is calculated as per BOSS 76 formula given below:

$$t_{mi} = D\left(\frac{50\,P_E}{E}\right)^{0.4845} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

Where

| | | |
|---|---|---|
| $t_{mi}$ | = | Buckle initiation minimum wall thickness, |
| E | = | Young's modulus, |
| $P_E$ | = | External pressure |

$t_{mi}$ = 71.12 (50*145/1975190.305)$^{0.4845}$

$t_{mi}$ = 4.7 cm

Pressure for buckle initiation as per BOSS 76 formula is calculated as,

$$P_{INIT} = 0.02\,E\left(\frac{t}{D}\right)^{2.064} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

Where t = selected wall thickness

$P_{INIT}$ = 0.02*1975190.305*(1.27/71.12)$^{2.064}$

$P_{INIT}$ = 9.75 kgf/cm$^2$

### 4.9.2 BUCKLE PROPAGATION

The nominal wall thickness excluding corrosion allowance, $t_{np}$ will be calculated as per DNV 1981.

$$t_{np} = \frac{D[P_E/(1.15\,\pi\ \mathrm{SMYS})]^{0.5}}{1+[P_E/(1.15\,\pi\ \mathrm{SMYS})]^{0.5}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

$t_{np}$ = 71.12{145/1.15*π*4588.72}$^{0.5}$/1+{{145/1.15*π*4588.72}$^{0.5}$

**$t_{np}$ = 6.1cm**

Pressure for buckle propagation

$$P_{prop} = 1.15\,\pi\,SMYS\left(\frac{t}{D-t}\right)^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

Where t is the selected wall thickness.

$P_{prop} = 1.15*\pi*4588.72(1.27/71.12-1.27)^2$

**$P_{prop}$ = 5.5 kgf/cm$^2$**

### 4.9.3 PIPE COLLAPSE

A pipeline resting on the seafloor is checked against collapse due to External pressure. For a pipe with a degree of out of roundness, the wall thickness for pipe collapse $t_{mc}$ is calculated as follows:

$$(a\,P_E)^2 - \left[2\,SMYS\frac{t_{mc}}{D} + \left(1 + 0.03\frac{U\,D}{t_{mc}}\right)C\right](a\,P_E) + 2\,SMYS\frac{t_{mc}}{D}C = 0$$

………………

$$\text{Where} \quad C = * \frac{2E}{1-\nu^2} \quad \frac{(t_{mc})^3}{D^3} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

| | | |
|---|---|---|
| U | = | Ovality % |
| $\nu$ | = | Poisson's ratio |
| $t_{mc}$ | = | Design minimum wall thickness for collapse |
| a | = | Safety factor (2) |

$C = 2*1975190.305/[1-(0.3)^2] * (t_{mc})^3/(71.12)^3$

$C = 12.06\ t_{mc}^3$

putting value of C in equation
**$t_{mc}$ = 1.79 cm**

## 4.9.4 CALCULATION FOR CONCRETE COATING THICKNESS (TAKING CARE OF BUOYANCY EFFECT)

**Pipeline Parameters**

| | |
|---|---|
| Diameter of pipe (D) | =28"=71.12cm |
| Density of steel ( $\rho_{steel}$ ) | = 7850 Kg/m3 |
| Wall thickness (t) | = 1.27cm |
| Coating density ( $\rho_{coating}$ ) | = 950 kg/m3 |
| Coating thickness ($t_c$) | = 2.5mm |
| Density of fluid ( $\rho_{fluid}$ ) | = 1040 kg/m3 |
| Concrete coating density ( $\rho_{concrete}$) | = 2250 kg/m3 |
| Concrete coating thickness ($t_{cr}$) | = ? |

Weight of pipe = $\frac{\Pi}{4}\left(D^2-(D-2t)^2\right)\times\rho_{steel}$ ..................(11)

= 3.14/4 $\{(0.7112)^2-(0.7112-2*1.27*10^{-3})^2\}*$ 7850

= 344 kg/m.

Weight of coating = $\frac{\Pi}{4}\left((D+2t_c)^2-D^2\right)\times\rho_{coating}$ ..............(12)

= 3.14/4 $\{(0.711+2*1.27*10^{-3})^2-(0.711)^2\}*$ 950

= 2.59 kg/m

Weight of concrete coating

= $\frac{\Pi}{4}\left((D+2t_c+2t_{cr})^2-(D+2t_c)^2\right)\times\rho_{concrete}$ .............(13)

= 3.14/4 $\{(0.711+2*1.27*10^{-3}+2t_{cr})^2-(0.711+2*1.27*10^{-3})^2\}*$ 2250

= $7068.4t_{cr}^2+5036.2t_{cr}$ kg/m

Buoyancy is given by

$$= \quad \frac{\Pi}{4}\left((D+2t_c+2t_{cr})^2\right)\times \rho_{fluid} \ldots\ldots\ldots\ldots\ldots\ldots\ldots(14)$$

$$= \quad 3.14/4\{(0.711+2*1.27*10^{-3}+2t_{cr})^2 * 1040$$

$$= \quad 415.75 + 4t_{cr}^2 + 2.85t_{cr} \text{ kg/m}$$

Buoyancy = Total weight of pipe

Above equation will give the value for equilibrium state, but we want the negative buoyancy. So, we will find the concrete thickness for 1.5 to the total weight.

$1.5\{415.75 + 4t_{cr}^2 + 2.85t_{cr}\} = 7068.4t_{cr}^2 + 5036.2t_{cr} + 344 + 2.59$

After solving this quadratic equation

**$t_{cr}$ = 148 mm**

## 4.9.5 ALLOWABLE SPAN FOR BAR BUCKLING

Bar buckling compressive force, S is given below:

$$S = N + \frac{\pi}{4}(D-2t)^2 P_i - \frac{\pi}{4} D^2 P_e$$

A span within a restrained area experiences more compressive force than a span in the partially restrained area. Axial force, N is given by the following formula for restrained lines (compression considered positive).

$$N = [E\alpha\Delta T - \nu\sigma_h]A_S - T$$

$$N = \pi t(D-t)(E\alpha\Delta T - \nu\sigma_h) - T$$

where T is the residual tension which will be taken as zero for calculation purposes.

Hoop stress: $\sigma_h = P_i D/2 t_m$

$$\sigma_h = 116 * 71.12/2 * 1.27$$

$= \quad 3248 \text{ kgf/cm}^2$

$$N = \pi t(D - t)(E\alpha\Delta T - \nu\sigma_h) - T$$

$= \quad 3.14 * 1.27(71.12- 1.27)\{975190.305 * 11.7*10^{-7} (66-26.6) -0.3 *3248) - 0$

where T is the residual tension which will be taken as zero for calculation purposes.

N = 17947.5 kgf

Bar buckling compressive force, S is given below:

$$S = N + \frac{\pi}{4}(D - 2t)^2 P_i - \frac{\pi}{4} D^2 P_e$$

$S = 17947.5 + 0.785 (71.12\text{-}2*1.27)^2 * 116 - 0.785*(71.12)^2 *145$

S = 515530.36 kgf

The allowable span from bar buckling criteria ($L_b$):

$$L_b = \sqrt{\frac{2\pi^2 EI}{S}}$$

where,

| | | |
|---|---|---|
| E | = | Young's modulus of elasticity |
| I | = | Moment of inertia of pipe cross section |
| $\alpha$ | = | Co-efficient of thermal expansion |
| $\Delta T$ | = | Temperature differential ($T_2 - T_1$) |
| $T_2$ | = | Design temperature |
| $T_1$ | = | Installation temperature |
| $\nu$ | = | Poisson's ratio |
| $\sigma_h$ | = | Hoop stress |
| $A_S$ | = | Cross sectional area of pipe ($\pi$ t (D – t)) |

$L_b = ( 2 * (3.14)^2 * 1975190.305*78490.46/515530.36)^{0.5}$

$L_b = 2435$ cm

## RESULTS

| Diameter Inch (cm) | Grade | wall Thickness | Buckle initiation thickness and pressure (cm,kgf/$cm^2$ resp.) | Buckle propagation thickness and pressure (cm,kgf/$cm^2$ resp.) | Pipe collapse thickness (cm) | Concrete coating thickness (cm) | Allowab span buckling (cm) |
|---|---|---|---|---|---|---|---|
| 28" (71.12) | X-65 | 1.27 | 4.75,9.75 | 6.1,5.5 | 1.79 | 14.8 | 2435 |
| 18" (45.72) | X-65 | 3.6 | 1.982,26.2 | 45.6,12 | 5.63 | 4.402 | 1620 |

Table 7

### 4.9.6 STRESS-STRAIN RELATION:

An accurate prediction of pipeline collapse must take into account the nonlinear stress strain relation of the steel in plastic response after yield strength has been exceeded.

According to modern application of theories of elasticity to plasticity to methods

$\sigma = k\varepsilon$

$n = \varepsilon_i$

Where

$\sigma$ = stress in psi

$\varepsilon$ = strain in psi

n = strain hardening coefficient

k = constant

But

$\sigma = p/A_i, \quad \varepsilon = L_f - L_i/L_i$

Where

P = pressure

$A_i$ = initiation pressure

$L_f$ = final length of pipe

$L_i$ = initial length of pipe

With volume constant in placticity

$V_f = V_i$ or $A_iL_i = A_fL_f$

True stress

$\sigma = p/A_f = \sigma A_i/A_f = \sigma L_f/L_i = \sigma(1+\varepsilon)$

To determine value for n

Plastic instability at dp=0

$\varepsilon = l_n A_i/A_f = A_i = A_0e^{-\varepsilon}$

$dp = A_ie^{-\varepsilon}\, d\sigma - \sigma A_i\, e^{-\varepsilon}\, d\varepsilon = 0$

$d\sigma/ d\varepsilon = \sigma$

$\sigma = k\, \varepsilon^{-n}$

$d\sigma / d\varepsilon = k\,\varepsilon^{-n}$

Strain hardening coefficient for X-65 steels

| | | |
|---|---|---|
| Ultimate stress, ksi | = | 132 |
| Yield stress,ksi | = | 70.5 |
| Ultimate strain, in/in | = | 0.366 |
| Yield strain,in/in | = | 0.005 |

Now we know that

$\sigma = k\,\varepsilon^{-n}$

$\log \sigma = \log k + n \log \varepsilon$

$2.1025 = \log k + n\,(-0.4365)$

$1.1848 = \log k + n\,(-2.3010)$

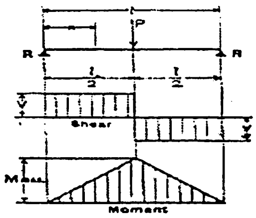
$n = 0.2723/1.864 = 0.146$

$k = \sigma / \varepsilon^{n} =$

$132/(0.366)^{0.146} = 152$

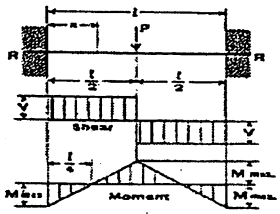
## BEAM DIAGRAMS AND FORMULAS
For various static loading conditions

### A. SIMPLE BEAM—CONCENTRATED LOAD AT CENTER



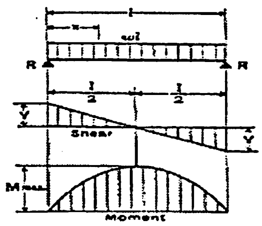

| | |
|---|---|
| Equivalent Tabular Load | $= 2P$ |
| R = V | $= \frac{P}{2}$ |
| M max. (at point of load) | $= \frac{Pl}{4}$ |
| $M_x$ (when $x < \frac{l}{2}$) | $= \frac{Px}{2}$ |
| $\Delta$max. (at point of load) | $= \frac{Pl^3}{48EI}$ |
| $\Delta_x$ (when $x < \frac{l}{2}$) | $= \frac{Px}{48EI}(3l^2 - 4x^2)$ |

### B. BEAM FIXED AT BOTH ENDS—CONCENTRATED LOAD AT CENTER



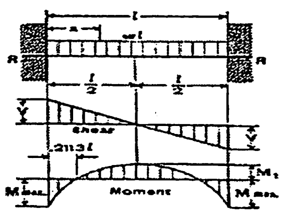

| | |
|---|---|
| Equivalent Tabular Load | $= P$ |
| R = V | $= \frac{P}{2}$ |
| M max. (at center and ends) | $= \frac{Pl}{8}$ |
| $M_x$ (when $x < \frac{l}{2}$) | $= \frac{P}{8}(4x - l)$ |
| $\Delta$max. (at center) | $= \frac{Pl^3}{192EI}$ |
| $\Delta_x$ (when $x < \frac{l}{2}$) | $= \frac{Px^2}{48EI}(3l - 4x)$ |

### C. SIMPLE BEAM—UNIFORMLY DISTRIBUTED LOAD




| | |
|---|---|
| Equivalent Tabular Load | $= wl$ |
| R = V | $= \frac{wl}{2}$ |
| $V_x$ | $= w\left(\frac{l}{2} - x\right)$ |
| M max. (at center) | $= \frac{wl^2}{8}$ |
| $M_x$ | $= \frac{wx}{2}(l - x)$ |
| $\Delta$max. (at center) | $= \frac{5wl^4}{384EI}$ |
| $\Delta_x$ | $= \frac{wx}{24EI}(l^3 - 2lx^2 + x^3)$ |

### D. BEAM FIXED AT BOTH ENDS—UNIFORMLY DISTRIBUTED LOADS




| | |
|---|---|
| Equivalent Tabular Load | $= \frac{2wl}{3}$ |
| R = V | $= \frac{wl}{2}$ |
| $V_x$ | $= w\left(\frac{l}{2} - x\right)$ |
| M max. (at ends) | $= \frac{wl^2}{12}$ |
| $M_1$ (at center) | $= \frac{wl^2}{24}$ |
| $M_x$ | $= \frac{w}{12}(6lx - l^2 - 6x^2)$ |
| $\Delta$max. (at center) | $= \frac{wl^4}{384EI}$ |
| $\Delta_x$ | $= \frac{wx^2}{24EI}(l - x)^2$ |

*Fig: 18 Beam Diagram For Various Static Loading Conditions*

**4.9.7 CONSIDERING PIPE AS UNIFORMLY LOADED, FIXED END BEAM.**

To locate zero moment

We know that

$M_x = -W/12[6LX-L^2 -6X^2]$

$= 6X^2 - 6LX+L^2$

Where

$M_x$ = moment

X- radial coordinate

L = length of pipe

Solving this quadratic equation

$X = 6L +-\sqrt{36L^2- 4*6L^2/12}$

X = 0.424L,0.788L

To locate 2/3 $M_{max}$

$M_x = w/12[6L_x - L^2 - 6X^2] = 2/3\ M_m = -2/3\ wl^2/12$

$= 6X^2 - 6\ LX +L^2/3$

By solving this equation

X = 0.0602L, 0.90940L

To locate 5/6 $M_{max}$

$6LX - L^2 - 6X^2 = -5/6\ L^2$

$X = 6L +-\sqrt{36L^2 -24L^2/6/12}$

X = 0.029L, 0.971L

### 4.9.8 DRIVING FORCES FOR UPHEAVAL AND LATERAL BUCKLING:

upheaval and lateral buckling are driven by the longitudinal compressive forces in the pipe wall and fluid contents. Calculation of longitudinal stress easily go wrong if they are not tackled systematically. The calculation are best carried out using a thin wall tube idealization.

In case with no external pressure, the circumferentially stress is statically determine and is given by the following formula:

$\sigma_H = P_i R/t$.........................................(a)

Where

$P_i$ = internal pressure

R = radius

t = wall thickness

the longitudinal strain $\varepsilon_L$ is given by the

$\varepsilon_L = 1/E(\sigma_H \upsilon + \sigma_L) + \theta\acute{\alpha}$ ...............................(b)

where

E = young modulus

$\sigma_H$ = circumferential stress

$\sigma_L$ = longitudinal stress

$\upsilon$ = poisson ratio

$\acute{\alpha}$ = linear thermal expansion coefficient

$\theta$ = change of temperature

the longitudinal stress is not statically determinate but depends on the extent to which longitudinal movment is constrained. If there is compete axial constrained

$\varepsilon_L = 0$ .........................(c)

Equations a.b.c together gives the longitudinal stress

$\sigma_L = \upsilon * P_i R/t - E\,\theta\acute{\alpha}$....................(d) longitudinal stress therefore has two components: the first related to pressure and seciond related to temperature. The pressure component is usually positive while temperature component is negative.

The cross section area of the pipe wall is $2Rt\pi$.

The longitudinal force in the pipe wall is as follow:

$2Rt\pi\ \sigma_H = 2R^2P_i\pi\ \upsilon - 2Rt\pi\ E\ \theta\acute{\alpha}$.........(e)

there is additional component of longitudinal force in the pipe contents. The cross section area is $\pi R^2$

and the longitudinal stress in the contents is $-P_i$. Therfor the longitudinal force in the contents is following

$-\pi R^2 P_i$.....................................(f)

Adding equation (e) and (f)

$-(1-2\ \upsilon)\ \pi R^2 P_i - 2Rt\pi\ E\ \theta\acute{\alpha}$.......................(g)

which has both a pressure term and temperature term. In most cases $\theta$ and $P_i$ both positive and $(1-2\ \upsilon)$ is always positive. Then both terms in equation (g) are negative and therefore compressive.

The presence of the compressive pressure term suggests that the pressure alone can causes upheaval buckling.

### 4.9.9 AISC BUCKLING PROPORTIONALITY

When pipeline has dent in it or if the pipe is sufficiently out of round, then at certain pressure the pipe will plastically deform radially inward buckle longitudinally. If the pressure load is greater then the amount of stored energy, then the buckle will propagate along the length of pipeline. The amount of pressure to make the buckle propagate will depend upon type of failure. The pipe buckle and buckle propagates because of gross out of round or ding due to unplanned damage to the pipe. The radial velocity of buckle propagation is the function of pressure head i.e. difference between external pressure and propagation pressure.

According to Timoshenko formula for buckling of pipe.

**For external pressure only**

$\mathbf{P_e = 2E/1\text{-}\upsilon^2(t/D)^3}$

**For column buckling**

$\sigma_c = 2Et/D\sqrt{3}(1-\upsilon^2)$

Where

$P_c$ = external pressure, $kgf/cm^2$ (145)

E = young modulus of elasticity, $kgf/cm^2$ (1975190.305)

t = wall thickness, cm (1.27)

$\upsilon$ = poisson's ratio (0.3)

D = diameter of pipe, cm (71.12)

AISC = American institute of steel construction

AISC proportionality

$P/P_c + \sigma/\sigma_c = 1$

Due to restraint of pipeline to freely expand longitudinally

$1 = P/P_c\,[1 + 0.15D/t\,(2.20)\,E\,(t/D)^3/1.21Et/D]$

Now putting values in equations

$P_e = 2E/1-\upsilon^2\,(t/D)^3$

$P_e = 2*1975190.305/(1-0.3^2)*(1.27/71.12)^3$

$P_e = 24\ kgf/cm^2$

For column buckling

$\sigma_c = 2Et/D\sqrt{3}(1-\upsilon^2)$

$\sigma_c = 2*1975190.305*1.27/71.12*\{3*(1-0.3^2)\}^{0.5}$

$\sigma_c = 3297.02mpa$

Due to restraint of pipeline to freely expand longitudinally

$1 = P/P_c\,[1 + 0.15D/t\,(2.20)\,E\,(t/D)^3/1.21Et/D]$

$1 = P/P_c\,[1+0.15\ 1.12/1.27(2.20)1975190.305(1.27/71.12)^3/1.21975190.305*1.27/71.12]$

$P = 0.9P_c$

Therefore longitudinal restraint causing biaxial loads has negligible effecton the elastic collapse pipe.

### 4.9.10 BUCKLE PROPAGATION VELOCITY

$V_r = (2gH)^{0.5}$

But

$H = P - P_{prop}/\rho$

Where

H = depth

P = external pressure

$P_{prop}$ = buckle propagation pressure

$\rho$ = density of material (taking $7900 kg/m^3$)

$V_r = \{2g/\rho \ (P - P_{prop})\}^{0.5}$

$V_r$ = 186.12 cm/sec.

Assuming liner velocity

$V_L$ = 200 cm/sec.

$\tan\beta = V_r/V_L$

$\tan\beta = 186.12/200$

$\beta = 42^0 56'$

## 5.0 DISCUSSSIONS

After putting the field on the production the main aim of the E&P companies is to run the facilities with minimum down time and thus reducing the maintenance cost incurred in production and transfer facilities. E&P companies generally have 3 strategies available at their disposal for maintaining offshore pipeline:

1) To have all the equipments, vessels, human resources and tools required to carry maintenance work for offshore pipeline.

**Advantages:** (A) minimum shorter time as resources are available at all the time.

(B) Equipments, tools and resources can be put on rent to other operators thus it can be source of income.

(C) Safeguard the companies from higher maintenance and service cost which are highly influenced by oil prices.

**Disadvantages:** (A) this can increase inventory cost of the company.

(B) This option may not be feasible for small or medium size company.

(C) In time of no failures the resources may become idle, if not rented and can increase the cost of the company.

(D) Maintenance cost of these equipments can increase the overall maintenance cost of the company.

2) The other strategy which the company can pursue is hiring the required resources for maintenance of pipeline. There are various service providers worldwide which provide services in maintenance of offshore pipeline. These service providers have contemporary technology, knowledge and expertise in these fields.

**Advantages:** (A) the company can hire the best available service for maintaining their assets thus take advantage of new technology and expertise.

(B) Company can select service providers keeping cost to be incurred in mind.

(C) After becoming the regular customer company can take waiver from the service provides on various front.

(D) No inventory cost and human resources required.

(E) Companies can use them for training its employee.

**Disadvantages:** (A) it may lead to high down time.

(B) This strategy can expose the company to dynamic market where prices of services can vary wildly by depending upon external environments.

3) The third strategy which companies can opt is mutual add scheme in which the different companies pool their resources for maintenance purpose. So when any company encounters any failure the other companies provide help and services to that company to ratify that failure. To pursue this strategy efficiently an MOU (memorandum of understanding) is signed between the companies. Specifying every aspect of resources to be pooled causes in which they have to come for help, economic involved etc.

**Advantages:** (A) small and medium size companies can get best services at low cost.

(B) Exchange of expertise, knowledge, technology.

(C) Operators can learn from the failure encountered in other operators owned pipeline thus reduce the probability of happing of failure.

(D) Low inventory level

(E) Companies are prevented from outside market variability.

Problems: It would be difficult to have mutual in area where one or two operators are working.

**Disadvantages:** If the problems occur simultaneously in two or more organization, then resources may not be adequate. However occurrence of such situations may not be common.

# 6.0 CONCLUSION

With the advent of the technology, there arises a problem failure, which has to be regularly inspected and controlled in order to have smooth operations. In order to maintain the integrity of offshore pipeline where leak, buckling, corrosion and rupture are the common problem encountered which are to be tackled. We use latest technology called SCADA, which provide round the clock alertness of leak failure. Use of equipments like Gauging plate , ROV are useful to detect the buckle in offshore pipeline. The corrosion problem can be detected by using ILI devices, cleaning PIGS. The rupture can be detected by using MPI inspection device.

Companies operating offshore pipelines in INDIA may explore the following to keep their readiness to address the maintenance needs of their offshore pipelines with the lowest possible cost, without delay in initiation of maintenance of jobs. Companies can opt a mutual add scheme in which the different companies pool their resources for maintenance purpose.

**Advantages:** (A) small and medium size companies can get best services at low cost.

(B) Exchange of expertise, knowledge, technology.

(C) Operators can learn from the failure encountered in other operators owned pipeline thus reduce the probability of happing of failure.

(D) Low inventory level

(E) Companies are prevented from outside market variability.

**Limitations:** If the problems occur simultaneously in two or more organization, then resources may not be adequate. However occurrence of such situations may not be common.

Technologies, which we have discussed in the project, enable us to identify the failure and repair it. If those technologies are not available for maintaining the sub sea pipeline, than

(A) Failure of pipeline can causes release of hydrocarbon in to the seawater, thereby affecting the flora and fauna present in the sea.

(B) Sub sea pipeline failures can cause a company to loose billions of dollars in claims penalty etc. if not counted on time.

(C) Company(s) may not be able to maintain its goodwill.

# 7.0 RECOMMENDATION

1. If more than one company operating at same location they can keep the maintenance and equipment resources at centralized location so that whenever problem arise they can use those resources for their maintenance and repair works which leads to reduction of the overall cost.
2. The companies can reach in to an agreement by signing an MOU so that they can share the knowledge expertise as well as technological advancements for the integrity of the pipelines.
3. the companies should sign an MOU with that company (s) which operates its own vessels for the maintenance of the pipeline which result in the overall cost.
4. a club of offshore pipelines companies should be created for mutual aid in specific case of emergency.
5. A contingency plan should be created in case of emergency.

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