A Project on

PIPELINE INTEGRITY ASSESSMENT AND MANAGEMENT

Submitted as a part of course work in
M. Tech (Pipeline Engineering)

By

THOMAS ANTONY,
B.Tech (*Mech. Engg.*)

2

<u>*Under the Mentorship of*</u>

Mr. V.V. Kondaiah
Assistant Professor,
College of Engineering Studies
UPES, Rajahmundry.

विद्याया शक्ति वशम्

COLLEGE OF ENGINEERING STUDIES
UNIVERSITY OF PETROLEUM AND ENERGY STUDIES
Rajahmundry Regional Centre
Rajahmundry-533 294
Andhra Pradesh

2008-09

CERTIFICATE

This is to certify that the project work entitled **"Pipeline Integrity Assessment and Management"** being submitted by **Mr. Thomas Antony**, in partial fulfillment of the requirement for the award of the degree of Master of Technology in Pipeline Engineering from University of Petroleum and Energy Studies-Rajahmundry, is a bonafide project work carried out by him under my guidance.

Mr. Thomas Antony fulfills all the requirements of the regulations laid down for the award of the degree of Master of Technology.

The content of this report has not been submitted to any university or institution by me or him for the award of any degree or diploma.

Mr V.V.Kondaiah

Assistant Professor, UPES

ACKNOWLEDGEMENT

I wish to acknowledge my sincere thanks to **Prof. K.V.Rao**, Academic Head, College of Engineering Studies, Dr. **K.V.Mohana Rao**, Centre Director, Rajahmundry Regional Centre, UPES.

I would like to thank Mr. **A.V.Rao**, Course Coordinator – M.Tech (Pipeline Engineering) for his constant support and guidance. I also don't want to miss the opportunity to express my thanks to **Mr. George Antony**, Manager-Mechanical, of **GAIL**, Rajahmundry for his valuable advice, resourceful guidance and inspiring instructions.

I take this opportunity to express my gratitude to my mentor **Mr.V.V.Kondaiah**, Assistant Professor, College of Engineering Studies, UPES - Rajahmundry for his valuable advice and resourceful guidance.

27/02/09

(THOMAS ANTONY)

Abstract

Pipelines provide a vital means of transportation. Pipelines also offer a relatively safe mode of transporting hazardous materials, as witnessed by the few recorded incidents of fatality or injury despite millions of kilometers of pipelines in use worldwide. Pipeline Integrity is the ability of a pipeline to operate safely and withstand the stresses imposed during operation. Pipeline need to be safe, reliable, efficient and economic in operations. Failures cannot be swallowed due to damaging consequences on Public, Financial, and Political and environmental. Pipeline failures can be due to various causes. It can be Human Errors, Equipment Failures, System or procedural failures and External Events. Failures caused by third party external mechanical interference includes cases like damaged by excavators or other equipment in use by other utility or construction companies, damage following derailments on railroads, hot tap in error by other utilities and damage during deep plowing by farmers. Hydro test can be a tool to prove the line integrity. Quantitatively on-line inspection survey can prove the line by follow up repair of all significant defects detected and sized accurately. It is in this context that pipeline operators are & shall now be compelled to go for in-service proving of their lines by on-line inspection techniques.

TABLE OF CONTENTS

LIST OF FIGURES

1. INTRODUCTION

Managing the integrity of a pipeline system is the primary goal of every pipeline system operator. Operator wants to continue providing safe and reliable delivery of various products to their customer without adverse effect on employees, the public, customers, or the environment. Incident free operation has been and continuous to be the pipeline industry's goal.

An integrity management programs provide the information the information for an operator to effectively allocate resources for appropriate prevention, detection and mitigation activities that will result in improved safety and a reduction in the number of incidents.

The requirements for prescriptive and performance based integrity management programs are provided detail in the coming part of this report. The performance based integrity management program alternatives utilizes more data and more extensive risk analysis, which enables the operator to achieve a greater degree of flexibility in order to meet or exceeds the requirements specifically in the areas of inspection intervals , tools used, and mitigation techniques employed. The level of assurance of a performance based program or an alternative international standards must meet or exceed that of a prescriptive program.

This report is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. A set of principles is the basis for the intent and specific details of this report. They are enumerated here so that we can understand the breadth and depth to which the integrity shall be an integral and continuing part of the safe operation of a pipeline system.

2. INTEGRITY MANAGEMENT PRINCIPLES

Functional requirements for integrity management shall be engineered into new pipeline systems from initial planning, design, material selection and construction. Integrity management of a pipeline starts with sound design, material management and construction of pipeline. Complete record of material, design and construction for the pipeline are essential for the initiation of a good integrity management program. Periodic evaluation is required to ensure the program takes appropriate advantage of improved technologies and the program utilize the best set of prevention, detection and mitigation activities that are available for the conditions at that time.

Information integration is the key component for managing system integrity. A key element of integrity management frame work is the integration of all pertinent information when performing risk assessment. Information that can impact an operator's understanding of the important risks to a pipeline system comes from variety of sources. The operator should be in best position to gather and analyze this information. By analyze all pertinent all of the pertinent information, the operator can determine where risks of an incident are the greatest, and make prudent decision to assess and reduce those risks.

Risk assessment is an analytical process by which an operator determines the type of adverse events or condition that might impact pipeline integrity. Risk assessment also determines the likelihood or probability of those events or

Conditions that will leads to a loss of integrity, and the nature and severity of the consequences that might occur following failure. This analytical process involve the integration of design, construction, operating, maintenance, testing, inspection and other information about a pipeline system.

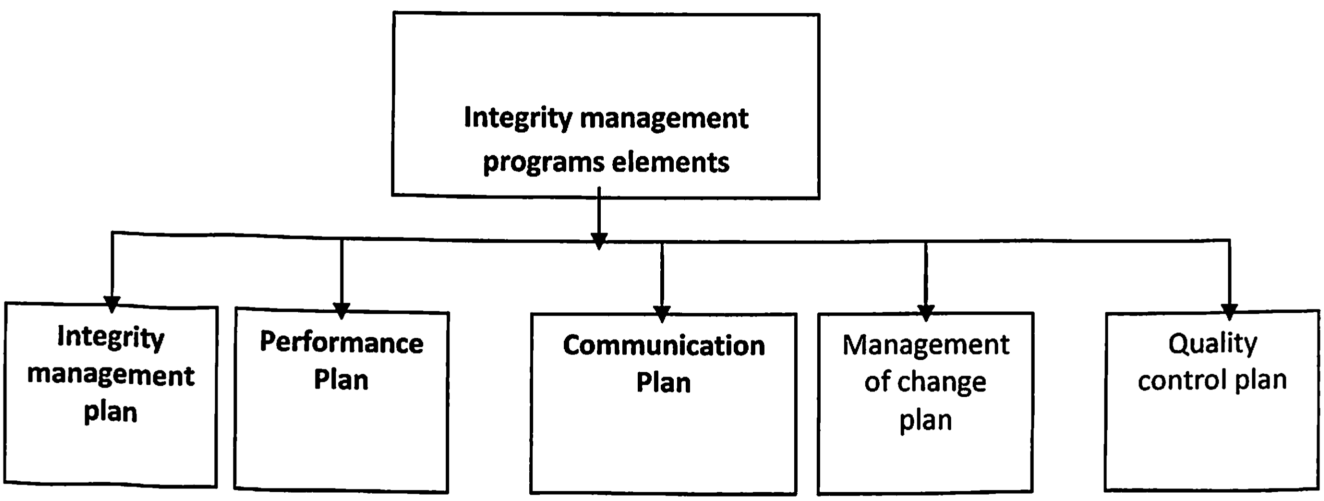
Performance measurement of a system and the program itself is an integral part of a pipeline integrity management program. Each operator can choose significant performance measures at the beginning of the program and then periodically evaluate results of these measures to monitor and evaluate the effectiveness of the program.

Periodic reports of effectiveness of an operator's integrity management program shall be issued and evaluated in order to continuously improve the program. Integrity management activities shall be communicated to the appropriate stake holders. Each operator shall ensure that all appropriate stake holders are given the opportunity to participate in the risk assessment process and the results are communicated effectively.

3. INTEGRITY MANAGEMENT PROGRAM OVERVIEW

This paragraph describes the required the elements of an integrity management program. These programs elements collectively provide the basis for a comprehensive, schematic and integrated integrity management program. The program elements depicted in the below figure are required for all integrity management programs.

Fig 1 : Integrity management programs elements



The performance based integrity management methods required more knowledge of the pipeline, and consequently more data-intensive risk assessment and analyze can be complete. The resulting performance based integrity management program can contain more option for inspection interval, inspection tool, and mitigation and prevention methods. A performance based program cannot be implemented until the operator has performed adequate integrity assessments that provide the data for performance based program.

A performance based integrity management program shall be including the following in the integrity plan.

1) A description of the risk analysis method employed

2) Documentation of all of the applicable data for each segment and where it was obtained.
3) A documented analysis for determine the integrity assessment intervals travels and mitigation (repair and prevention) methods.
4) A documented performance matrix that, in time, will confirm the performance based option chosen by the operator.

   The processes for developing and implementing a performance based integrity management program are included.

3.1 INTEGRITY THREAT CLASSIFICATION

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analyzed and classified by the pipeline research committee international (PRCI) into 22 root causes. Each of these 22 causes represents a threat to pipeline integrity that shall be managed. All these threats are grouped into nine categories of related failure types according to their nature and growth characteristics, and further delineated by three time related defect types.

The nine categories are useful in identifying potential threats. Risk assessment, and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

a) Time Dependent
   1) External corrosion
   2) Internal corrosion
   3) Stress corrosion cracking
b) Stable
   1) *Manufacturing related defects*
      - Defective pipe seam
      - Defective pipe
   2) *Welding/fabrication related*
      - Defective pipe girth weld

- Defective fabrication weld
- Wrinkle bend or buckle
- Stripped threads/broken pipe/coupling failure

3) *Equipment*

- Gasket O-ring failure
- Control/relief equipment malfunction
- Seal/Pump packing failure
- Miscellaneous

c) Time-independent

1) *Third party/Mechanical damage*

- Damage inflicted by first, second or third parties (instantaneous/immediate failure)
- Previously damaged pipe (Delayed failure mode)
- Vandalism

2) *Incorrect operational procedure*

3) *Weather related and outside force*

- Cold water
- Lightening
- Heavy rains or floods
- Earth movements

3.2 THE INTEGRITY MANAGEMENT PROCESS

The integrity management process include

a) Identify potential pipeline impact by threat

This program element involves the identification of potential threats to the pipeline especially in the areas of concern.

b) Gathering, reviewing and integrated data

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segment and the potential threats to that segment. In this step, the operator performs the initial collection, review and integration of relevant data and information that is needed to understand the condition of pipeline, identify the location of specific threats to integrity, understand the public, environmental, and operational consequences of an incident.

c) Risk assessment

In this step, the data assembled from the previous steps are used to conduct a risk assessment of the pipeline system and segments. The risk assessment process identifies the location of specific events and conditions that could lead to a pipeline failure, and provides an understanding of the likely hood and consequences of an event.

d) Integrity assessment

Based on the risk assessment made in the previous steps, the appropriate integrity assessment are selected and conducted. Details of various steps for assessment will discussed later.

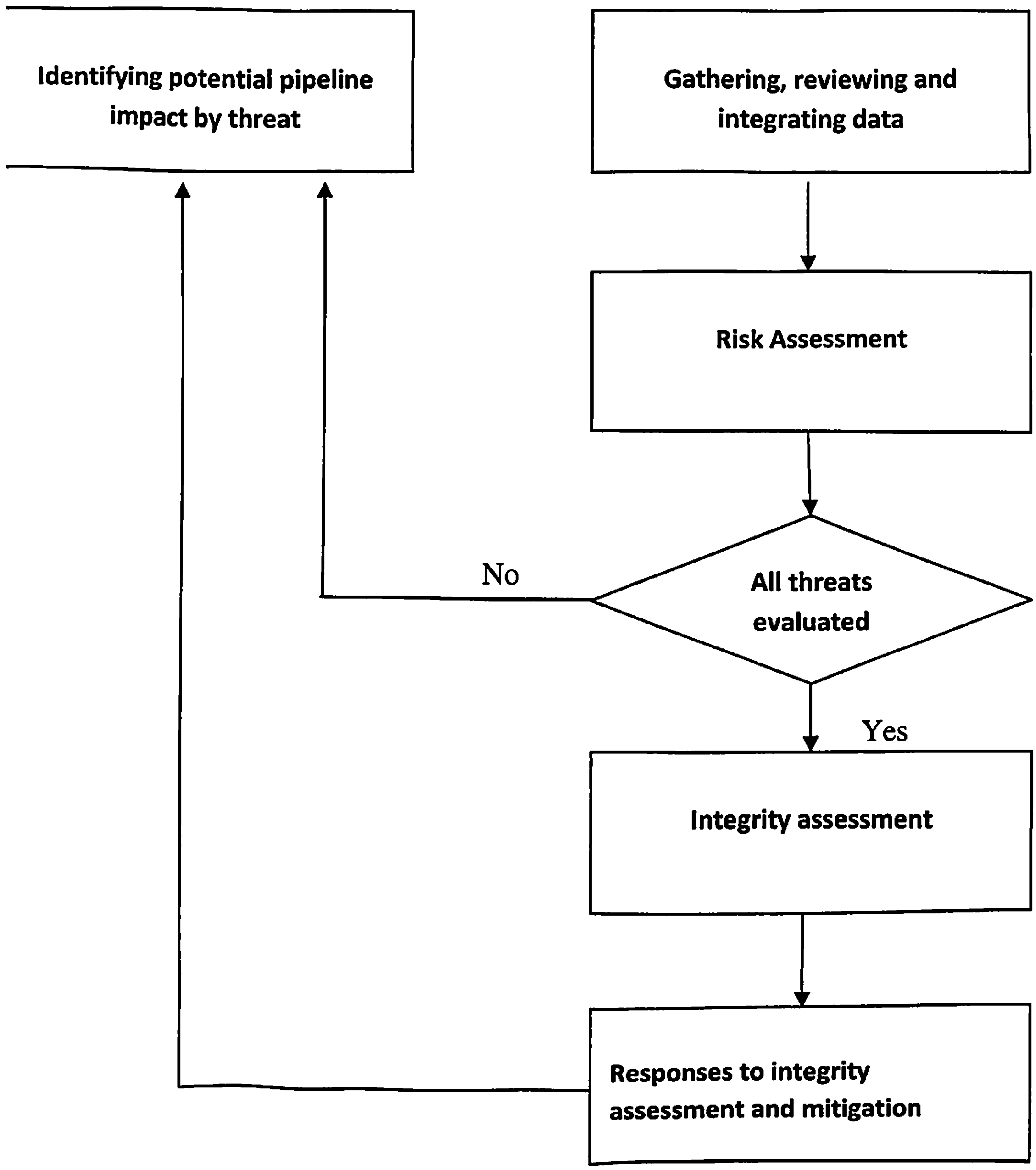
e) Update, integrate and review data

After the initial integrity assessments have been performed, the operator has improved and updated information about the condition of the pipeline system or segment. This information shall be retained and added to the database of information used to support future risk assessments and integrity assessments. Furthermore, as the system continues to operate, additional operating, maintenance, and other information is collected, thus expanding and improving the historical database of operating experience.

f) Reassess risk

Risk assessment shall be performed periodically within regular intervals, and when substantial changes occur to the pipeline. The operator shall consider recent operating data, consider changes to the pipeline system design and operation, analyze the impact of any external changes that may have occurred since the last risk assessment, and incorporate data from risk assessment activities for other threats, the results of integrity assessment, such as internal inspection, shall also be factored into future risk assessment, to assure that the analytical process reflects the latest understanding of pipe condition.

Fig 2: Integrity management flow process flow diagram



4. CONSEQUENCES

Risk is the mathematical product of the likelihood and the consequences of the events that result from the failure. Risk may be decreased by reducing either the likelihood or the consequence of a failure, or both. This part specially addressed the consequence portion of the risk equation. The operator shall consider consequences of a potential failure when prioritizing inspections and mitigation activities.

The B31.8 code manages risk to pipeline integrity by adjusting design and safety factors, and inspection and maintenance frequency, as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequence of a failure.

Potential impact area

The radius of impact for natural gas is calculated using the formula

$r = 0.69 * d\sqrt{p}$,

Where

d= outside diameter of the pipeline, in

p = pipeline segment's maximum allowable operating

Pressure (MAOP), psig

r = radius of impact, circle, ft.

Consequence factors to consider

When evaluating the consequence of a failure within the impact zone , the operator shall consider at least the following:

a) Population density

b) Proximity of the population to the pipeline including consideration of manmade or natural barriers that may provide some level of protection.

c) Proximity of population with limited or impaired mobility

d) Property damage

e) Environment damage

f) Effect of un ignited gas release

g) Security of gas supply

h) Public convenience and necessity

i) Potential for secondary failures

Note that the consequence s may vary based on the richness of the gas transported and as a result of how gas is decompresses. The richer the gas, more important defect and material properties are in modeling the characteristics of the failure.

5. GATHERING, REVIEWING AND INTEGRATING DATA

This part provides a systematic process for pipeline operators to collect and effectively utilize the data elements necessary for risk assessment. Comprehensive pipeline and facility knowledge is an essential component of a performance based integrity management program. In addition, information on operational history, the environment around the pipeline, mitigation techniques employed and process /procedure review is also necessary

Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for integrity management program.

A) Data requirements

The operator shall have a comprehensive plan for collecting all data sets. The operator must first collect the data required to perform a risk assessment. Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate threats.

B) Performance based integrity management programs

There is no standard list of required data elements that can apply to all pipeline systems for performance based integrity management programs. However, the operator shall collect at a minimum, those data elements specified in the prescriptive based program requirements. The quantity and specific data elements will vary between operators and within a given pipeline systems.

Fig 3: Data element for prescriptive pipeline integrity management

Attribute data	Pipe wall thickness Diameter Seam type and joint factor Manufacturer Manufacturing date Material properties Equipment properties
construction	Year of installation Bending method Joining method, process and inspection results Depth of cover Crossing/casing pressure test field coating methods soil, backfill inspection reports Cathodic protection installed coating type
Operational	Gas quality Flow rate Normal maximum and minimum operating pressures Leak/failure history Coating condition CP (Cathodic protection) system performance

Operational	**Pipe wall temperature** **Pipe inspection reports** **OD/ID corrosion monitoring** **Pressure fluctuations** **Regulator/relief performance** **Encroachments** **Repair** **Vandalism** **External forces**
Inspection	**Pressure test** **Inline inspection** **Geometry tool inspection** **Bell hole inspections** **Cp inspection(CIS)** **Coating condition inspection(DCVG)** **Audits and reviews**

6. RISK ASSESSMENT

Risk assessment shall be conducted for pipelines and related facilities. Risk assessment is required for both prescriptive and performance based integrity management programs.

For prescriptive based programs, risk assessments are primarily utilized to prioritize integrity management plan activities. They help to organize data and information t o make decisions.

For performance based programs, risk assessments serve the following purposes

a) To organize data and information to help operators prioritize and plan activities
b) To determine which inspection, prevention and or mitigation activities will be performed and when.

6.1 Risk assessment objectives

For application to pipeline and facilities, risk assessment has the following objectives

a) Prioritization of pipeline/segments for scheduling integrity assessment and mitigation action.
b) Assessment of the benefits derived from mitigation action.
c) Determination of the most effective mitigation measures for the indentified threats.
d) Assessment of the integrity impact from modified inspection interval.
e) Assessment of the use of or need for alternative inspection methodologies.
f) More effective resources resource allocation.

Risk assessment provides a measure that evaluates both the potential impact of different incident types and likelihood that such events may occur. Having such a measure supports the integrity management process by facilitating rational and consistent decision. Risk results are used to identify the location for integrity assessment and resulting mitigation action.

Fig 5: Integrity assessment intervals

Time dependent threats, prescriptive integrity management plan

inspection testing	Interval (years)	criteria		
		at or above 50% smys	**at or above 30% up to 50% SMYS**	**less than 30% SMYS**
hydrostatic testing	5	TP to 1.25 times MAOP	TP to 1.4 times MAOP	TP to 1.7 times MAOP
	10	TP to 1.39 times MAOP	TP to 1.7 times MAOP	TP to 2.2 times MAOP
	15	not allowed	TP to 2.0 times MAOP	TP to 2.8 times MAOP
	20	not allowed	not allowed	TP to 2.0 times MAOP
inline inspection	5	pf above 1.25 times MAOP	pf above 1.4 times MAOP	pf above 1.7 times MAOP
	10	pf above 1.39 times MAOP	pf above 1.7 times MAOP	pf above 2.2 times MAOP
	15	not allowed	pf above 2.0 times MAOP	pf above 2.8 times MAOP
	20	not allowed	not allowed	pf above 3.3 times MAOP
Direct assessment	5	sample indications examined	sample of indications examined	sample of indications examined
	10	all indications examined	sample of indications examined	sample of indications examined
	15	not allowed	all indications examined	all indications examined
	20	not allowed	not allowed	all indications examined

Note:

- **Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections.**
- **TP is the test pressure**
- **Pf is predicted failure pressure as determined from ASME B31G or equivalent**

6.2 Characteristics of an effective risk assessment approach

A number of general characteristics exit that will contribute to overall effectiveness of a risk assessment for either prescriptive or performance based integrity management program. Various characteristics are

a) **Attributes:**

Any risk assessment approach shall contain a defined logic and be structured to provide a complete, accurate and objective analysis of risk.

b) **Resources**

Adequate personnel and time shall be allotted to permit implementation of the selected approach and future consideration.

c) **Operating/Mitigation history**

Any risk assessment shall consider the frequency and consequence of past events. Preferably this should include the subject pipeline system of a similar system, but other industry data can be used where sufficient data is initially not available.

d) **Predictive capability**

To be effective, a risk assessment method is should be able to identify pipeline integrity threats previously not considered. It shall be able to make use of the data from various pipeline inspection techniques to provide risk estimate that result from threats that have not been previously recognized.

e) **Risk confidence**

Any data applied in a risk assessment process shall be verified and checked for accuracy. Inaccurate data will produce a less accurate risk result. For missing all questionable data the operator should determine and document the default values of others similar segment on the pipeline or in the operators system.

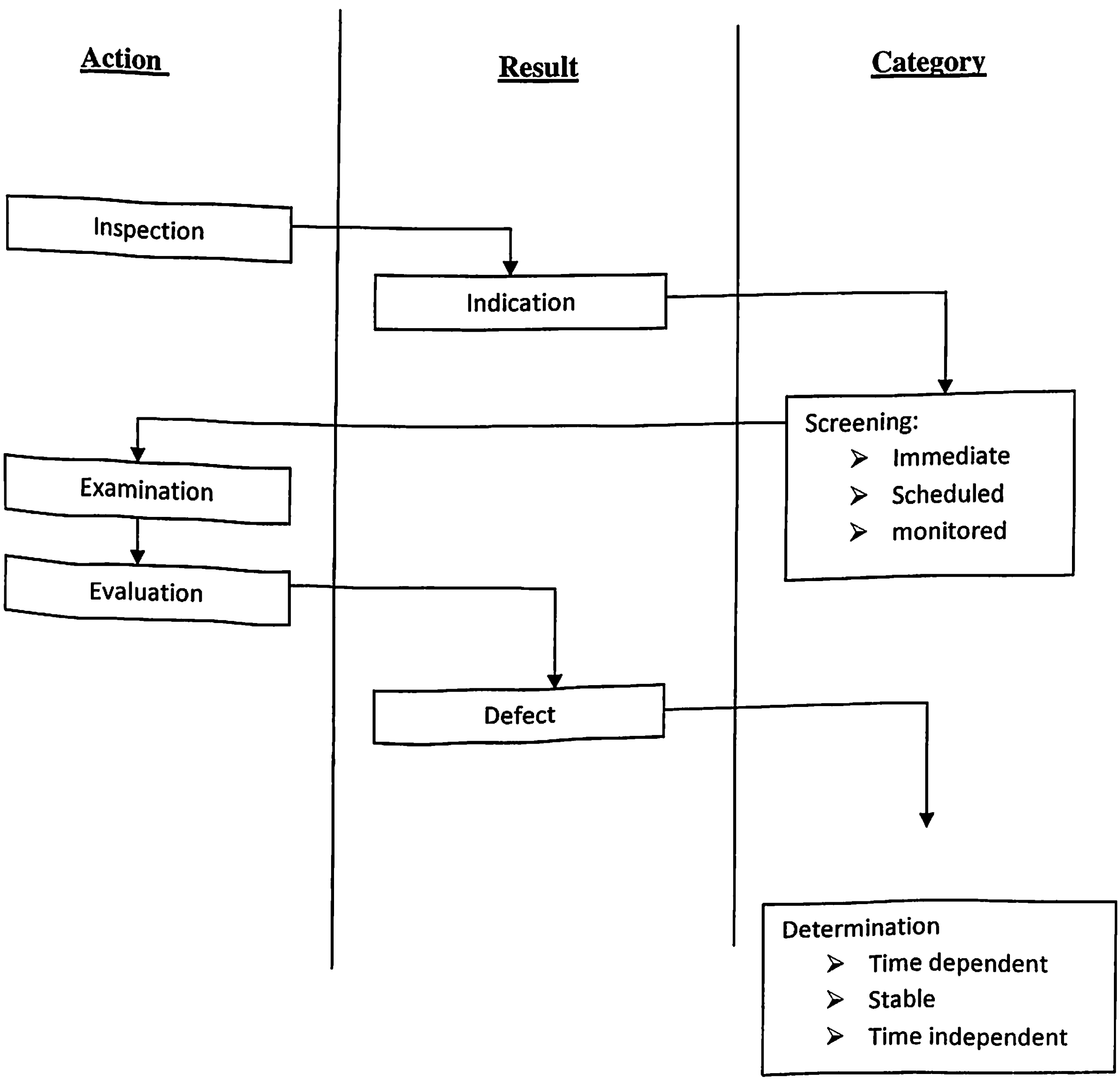
f) **Feedback**

One of the most important steps in an effective risk analysis is feedback. Any risk assessment methods shall not be consider as a starting tool, but as a process of continues improvement.

7. INTEGRITY ASSESSMENT

Based on the priorities determined by risk assessment, the operator shall conduct integrity assessment methods. The integrity assessment methods that can be used in line inspection, pressure testing, direct assessment for other methodologies. Since pipeline is accessible for various techniques and external corrosion can be readily evaluated, performing inline inspection which is described below is not necessary.

Fig 6: Hierarchy of terminology for integrity assessment



7.1 Pipeline inline inspection.

Pipeline inline inspection is an integrity assessment method used to locate and preliminary characterize metal loss indication in a pipeline. The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirement set by the inspection objective.

a) **Metal loss for the internal and external corrosion threats can be determined by following tools**

1. ***Magnetic flux leakage*, standard resolution tool**

   This is better suited for detection of metal loss than for sizing. Sizing accuracy is limited by sensor size. It is sensitive to certain metallurgical defects such as scabs and silvers. It is not reliable for the detection or sizing of axially aligned metal loss defects. High inspection speeds degrade sizing accuracy.

2. ***Magnetic flux leakage, high resolution tool.***

   This provides better sizing accuracy than standard resolution tools. Sizing accuracy is best for geometric ally simple defect shapes. Sizing accuracy degrades where pits are present or defect geometry becomes complex.

3. ***Ultrasonic compression wave tool***

   This requires a liquid couplant or a wheel coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the defect. Sizing accuracy is degraded by the presence of inclusion and impurities in the pipe wall.

b) Crack corrosion tool for the stress corrosion cracking threat.

1. ***Ultrasonic shear wave tool.***

   This required a liquid couplant or a wheel coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the crack colony. Sizing accuracy is degraded by the presence of inclusion and the impurities in the pipe wall.

2. ***Transverse flux tool.***

   This is able to detect some axial aligned cracks, not including SCC, but is not considered accurate sizing. High inspection speeds can degrade sizing accuracy.

c) Metal loss and caliper tools for third party damage and mechanical threat.

Dents and the areas of metal loss are the only aspects of these threats for which ILI tools can be effectively used for detection and sizing. Deformation or geometry tools are most often used for detection of damage to the line involving deformation of the pipe cross section, which can be caused by construction damage, dent caused by the pipe settling on to rocks, third party damage, wrinkles or buckles caused by compressive loading or uneven settlement of the pipeline.

d) Special consideration for the use of In-line inspection tools.

1) The following shall also be considered when selecting the appropriate tool:
   - detection sensitivity
   - Differentiation between types of anomalies.
   - Sizing accuracy: Enables prioritization and is a key to successful integrity management plan.

- Location Accuracy. Enables location of anomalies by excavation.
- Requirements for defect assessment: Result of ILI have to be adequate for the specific operator's defect assessment program

2) Typically, pipeline operators provide answers to questions provide by ILI vendor that should list all the significant parameters and characteristics of the pipeline section to be inspected. Some of the more important issue that should be considered are as follows:
    - Pipeline question
    - Launchers and receiver: should be reviewed for suitability, since ILI tools vary in overall length, complexity, geometry and maneuverability.
    - Pipe cleanliness
    - Types of fluids, gas or liquid, affecting the possible choice of technologies.
    - Flow rate, pressure and temperature. Flow rate of the gas will influence the speed of the ILI tools inspection. If speeds are outside of the normal ranges, resolution can be compromised
    - Product bypass/supplement: reduction of gas flow and speed reduction capability on the ILI tool may be consideration in higher velocity lines. Conversely, the availability of supplementary gas where the flow rate is too low shall be considered.
3) The operator shall asses the general reliability of the ILI method by looking at the following:
    - Confidence level of the ILI method (probability of detecting, classifying and sizing the anomalies)
    - History of ILI method/tool.
    - Success rate / failed surveys

- Ability of the tool to inspect the full length and full circumference of the section.
- Ability to indicate the presence of multiple cause anomalies.

7.2 Pressure testing

Pressure testing has long been an industry accepted method for validating the integrity of pipelines. This integrity assessment method can be both a strength test and a leak test. Selection of this method shall be appropriate for the threat being assessed.

ASME B31.8 contains details on conducting pressure tests for both pre construction testing and for subsequent testing after a pipeline have been in service for a period of time. It also specifies allowable test mediums and under what conditions the various test mediums can be used.

The operator should consider the results of the risk assessment and the expected types of anomalies to determine when to conduct inspections utilizing pressure testing.

a) Time dependent threats; pressure testing is appropriate for the use when addressing time dependent threat. Time dependent threats are external corrosion, internal corrosion cracking and other environmentally assisted corrosion mechanism.

b) Manufacturing and related threat defect threats: pressure testing is appropriate for the use when addressing the pipe seam aspect of the manufacturing threat. Pressure testing shall comply with the requirements of ASME 31.8. This will define whether air or water shall be used. Seam issue have been known to exist for pipe with a joint factor of less than 1.0(e.g., lap welded pipe, hammer welded pipe, and butt-welded pipe) or if the pipeline is comprised of low frequency welded electric resistance welded (ERW) pipe or flash welded pipe.

When raising the MAOP of a steel pipeline or when raising the operator pressure above historical operating pressure (ie, highest pressure recorded in 5 years) pressure testing must be performed to address the same issue. Pressure testing in accordance with ASME B31.8 is to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct test for both pre construction and in service pipelines.

7.3 Direct Assessment

Direct assessment is an integrity method utilizing a structured process through which the operator is able to integrate knowledge of physical characteristics and operating history of a pipeline system or segment with the result of inspection, examination and evaluation, in order to determine the integrity.

a) External corrosion direct assessment (ECDA) for external corrosion threat

External corrosion direct assessment can be used for determining the integrity for the external corrosion threats of the pipeline segment. The process integrates facilities data, and current and historical field inspection and tests, with the physical characteristics of a pipeline. Nonintrusive (typically above ground or indirect) inspections are used to estimate the success of the corrosion protection. The ECDA process requires direct examination and evaluations. Direct examination and evaluations confirm the ability of the indirect inspection to locate and past corrosion location of the pipeline. Post-assessment is required to determine a corrosion rate to set the re inspection interval, reassess the performance metrics and their current applicability, and ensure the assumptions made in the previous step remain correct.

The ECDA process therefore has the following four components

1) Pre-assessment
2) Inspection
3) Examinations and evaluation
4) Post assessment

The prescriptive ECDA process require the use of atleast two inspection methods, verifications checks by examination and evaluation and post assessment validation.

b) Internal corrosion direct assessment process (ICDA) for the internal corrosion threat.

Internal corrosion direct assessment can be used for determining integrity for internal corrosion threat on pipeline segments that normally carry dry gas but may suffer from short term upsets of wet gas or free water. Examinations at low points or at inclines along the pipelines, which forces an electrolyte such as water to first accumulate, provide information about the remaining length of pipeline. If these low points are not corroded, then other locations further downstream are less likely to accumulate electrolytes and therefore can be considered free from corrosion.

Examination is performed at locations where electrolyte accumulation is predicted. For most pipelines it is expected that examination by radiography or ultrasonic NDE will be required to measure the remaining wall thickness at those location. Once a site has been exposed, internal corrosion monitoring methods for example coupon, probe, ultrasonic sensor etc may allow an operator to extend the Reinspection interval and benefit from real time monitoring in the locations most susceptible to internal corrosion.

8. RESPONSES TO INTEGRITY ASSESSMENT AND MITIGATION (REPAIR AND PREVENTION)

This part covers the schedule of responses to the indication obtained by inspection, repair activities that can be affected to remedy or eliminate an unsafe condition, preventive actions that can be taken to reduce or eliminate a threat to integrity of a pipeline, and establishing the inspection interval. Inspection interval are based on the characterization of defect indications, the level of mitigation achieved, the prevention methods employed, and the useful life of the data, with consideration given to expected defect growth.

8.1 Responses to pipeline Inline inspections

An operator shall complete the response according to a prioritized schedule established by considering the result of a risk assessment and the severity of inline inspection indications. The required response scheduled interval begins at the time the condition discovered.

When establishing schedules, responses can be divided to following groups

a) Immediate: indication shows that defect is at failure point
b) Scheduled: indication shown defect is significant but not at failure point
c) Monitored: indication shows defect will not fail before next inspection.

Upon receipt of the characterization of indications discovered during successful inline inspection, the operator shall promptly review the results for immediate response indication. Other indication shall be reviewed within 6 months and a response plan will be developed.

1) **Metal loss tools for internal and external corrosion**

   Indications requiring immediate response are those that might be expected to cause immediate or near term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. This would also include any corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME B 31G or equivalent. Also in this group would be any metal loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding. The operator shall examine these indications within a period not less than 5 days following determination of the condition. After examination and evaluation, any defect found to require repair or removal unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

Indications in the scheduled group are suitable for continued operations without immediate response provided they do not grow to critical dimensions prior to the scheduled response. Indications characterized with a predicted failure pressure greater than 1.10 times the MAOP shall be examined and evaluated according to schedule.

2) **Crack detection tool for stress corrosion cracking**

All indication of stress corrosion cracks requires immediate response. The operator shall examine and evaluate these indications within a period not to exceed 5 days following determination of the condition. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair, removal or lowering the operating pressure.

3) **Metal loss and caliper tools for third party damage and mechanical damage**

Indications requiring immediate response are those that might be expected to cause immediate or near term leaks or rupture based on their known or perceived effects on the strength of the pipelines. These could include dent with gouges. The operator shall examine these indications within a period not to exceed five days following determination of the condition.

Indications requiring a scheduled response would include any indication on a pipeline operating it or above 30% of specified minimum yield strength (SMYS) of a plain dent that exceeds 6% of the nominal pipe diameter, mechanical damage with or without concurrent visible indentation of the pipe, dent with cracks, dent that affect ductile girth or seam welds if the depth is in excess of 2% OF The nominal pipe diameter, and dent of any depth that affect non ductile welds. The operator shall expeditiously examine these indications within a period not to exceed one year following determination of the condition. After examination and evaluation any defect found to require repair or removal shall be promptly remediated by a repair or removal, unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

8.2 Responses to pressure testing

Any defect that faces a pressure test shall be promptly remediated by repair or removal.

a) External and Internal corrosion threats: the intervals between tests for the external and internal corrosion threats is already discussed in the previous pages.

b) Stress corrosion cracking threats: the Interval between pressure test for corrosion cracking shall be as follows:

1. If no failure occurred due to SCC, the operator shall use one of the following options to address the long term mitigation of SCC:
   - A documented hydrostatic retest program with a technically justifiable interval or
   - An engineering critical assessment to evaluate the risk and identify further mitigation methods.
2. If a failure occurred due to SCC, the operator shall perform the following
   - Implement a document hydrostatic retest program for the subject segment and
   - Technically justify the retest interval in the written retest program

c) **Manufacturing and related defect threats**

A subsequent pressure test for the manufacturing threat is not required unless the MAOP of the pipeline has been raised or when the operating pressure has been raised above the historical operating pressure (highest pressure recorded in 5 years prior to the effective date of this supplement)

8.3 Response to direct assessment inspection.

a) External corrosion direct assessment (ECDA).

For the ECDA prescriptive program for pipelines operating at above 30% SMYS, if the operator choose to examine and evaluate all the indications found by inspection, and repairs all defect that could grow to failure in 10 years, then the re inspection interval shall be 10 years. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 5 years, provided an analysis is performed to ensure all remaining defect will not grow to failure in 10 years. The interval between determination and examination shall be consistent.

b) Internal corrosion direct assessment (ICDA).

For the ICDA prescriptive program, examinations and evaluation of all selected locations must be performed within 1 year of selection. The interval between subsequent examinations shall be consistent with below figure

Above figure contains three plots of the allowed time to respond to an indication based on the predictive failure pressure Pf divided by MAOP of the pipeline. The three plots correspond to

1. Pipeline operating at or above 50% SMYS
2. Pipeline operating at or above 30% SMYS but at less than 50%
3. Pipeline operating at less than 30% SMYS

The figure is applicable to the prescriptive based programs.

c) Repair methods

Each operator's integrity management program shall include documented repair procedures or repair shall be made with materials and processors that are suitable for the pipeline operating conditions.

8.4 Prevention options

An operator's integrity management program shall include applicable activities to prevent and minimize the consequences of unintended releases. Prevention activities do not necessarily require justification through additional justification data. Prevention actions can be identified during normal pipeline operation, risk assessment, implementation of the inspection plan, or during repair.

The predominant prevention activities presented above include information on the following:

a) Preventing third party damage

b) Controlling corrosion

c) Detecting unintended release

d) Minimizing the consequences of unintended release

e) Operating pressure reduction

9. QUALITY CONTROL PLAN

This paragraph describes the quality control activities that shall be part of an acceptable integrity management program

General: Quality control can be described as the documented proof that the operator meets all requirement of their integrity management program. Pipeline operators that have a quality control program that meets or exceeds the requirements can incorporate with the integrity management program activities within their existing plan. For those operators who do not have a quality program , this paragraph outlines the basic requirement of such a program.

9.1 Quality management control:

A. Requirement of a quality control program includes documentation, implementation and maintenance. The following six activities are usually required:
   a) Identify the process that will be included in the quality program.
   b) Determine the sequence and interaction of these processes
   c) Determine the criteria and methods needed to ensure that both the operations and control of these process are effective
   d) Provide the resources and information necessary to support the operation and monitoring of these process
   e) Monitor, measure and analyze these processes
   f) Implement actions necessary to achieve planned results and continued improvement of these processes

B. Specifically, activities that should be included in the quality control program are as follows:
   a) Determine the documentation required and include in the quality programs. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessment, the integrity management plan, integrity management reports and data management reports and data documents.

b) The responsibilities and authorities under this program shall be clearly and formally defined.

c) Results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvements.

d) The personal involved in the integrity management program shall be competent, aware of the program and all its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness and qualification and the process for achievement, shall be part of the quality control plan.

e) The operator shall determine how to monitor the integrity management program to show that it is been implemented according to plan and documented these steps. These control points, criteria, and/or performance metrics shall be determined.

f) Periodic internal audits of the integrity management program and its quality plan are recommended. An independent third party review of the entire program may also be useful.

g) Corrective action to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.

C. When an operator chooses to use outside resources to conduct any process (for example, pigging) that affects the quality of the integrity management programs, the operator shall ensure control of such process and document them within the quality program.

10. CONCLUSION

Pipeline Integrity management is an involved and detailed process using threat identification, risk analysis, assessment methods, evaluation, remediation, re-assessment and continuous improvement to accomplish one think – "*keep the product in the pipeline*". It assists in developing and implementing decision-making criteria, strategies and programs to effectively manage risks. Integrity management includes various pipeline systems includes pipes, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies. The principles and process embodied in integrity management are applicable to all pipeline systems.

11. REFERENCES AND STANDARDS

1) Common Ground: Study of One-Call systems and Damage prevention best practices

Publisher: Office of pipeline safety (OPS), research and special programs administration, U S Department of transportation, 400 seventh street, S W, Washington.

2) Guidelines for Technical Management Of Chemical Process Safety.

Publisher: Center for Chemical process safety (CCPS) of American Institute of Chemical Engineers, 3 Park Avenue, New York.

3) Juran's Quality Control Handbook (4th Edition)

Publisher: McGraw- Hill Book Company, 1221 Avenue of the Americas, New York

4) Pipeline Risk Management Manual(2nd Edition)

Publisher: Gulf Publishing Company, P.O Box 2608, Houston.

5) API 1160, Managing System Integrity for Hazardous liquid Pipelines

Publisher: American Petroleum institute (API), 1200 L Street, Washington.

6) ASME B31.8, Gas Transmission and Distribution Piping Systems

7) ASME B31G, Manual for determining the remaining strength of corroded Pipelines

8) ASME B31.8S-2004, Managing System Integrity of gas pipelines.

9) GRI-00/0076, Evaluation of pipeline design factors

10) GRI-00/0233, Quantifying Pipeline Design at 72% SMYS as a precursor to Increasing design Stress Level.