Managing Structural Integrity of Pipelines Utilising Inline Inspection Data

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Abstract — **Pipeline structural integrity challenges highlight the need for pipeline operators to prioritise inline inspection technologies as part of risk-based condition assessment. This initiative is motivated by increased regulatory and economic constraints associated with the worldwide ageing pipeline infrastructure. Inline inspection technologies are now extensively used to detect and inspect various anomalies and prevent unintended catastrophic pipeline failures. This paper outlines the importance of inline inspection technologies to collect data for structural integrity analysis. It also considers inline inspection technology selection, including performance and deterministic methods to interpret the inline inspection data. The deterministic methods assist in determining the remaining strength and useful life.**

Keywords—manage, pipeline, structural integrity, inline inspection

I. Introduction

With the increased need to expand pipeline distribution network systems globally, inline inspection tools ensure that pipelines perform their intended function. Inline inspection refers to preemptive structural integrity assessment to identify anomalies or defects that may result in the catastrophic failure of a pipeline. Pipeline's transport large quantities of water, oil, and gas to consumers over long distances. [1] opine that pipelines are susceptible to flaws, such as fatigue cracks, mechanical corrosion, microbiological induced corrosion, stray current corrosion, and stress corrosion cracking. [2] states that a pipe flaw is an unintentional imperfection in a pipe wall, and a defect is any flaw that does not meet structural integrity acceptance criteria. [3] firmly believe that financial losses due to unintended pipe failures may be reduced if adequately managed. This would also lead to improved health and safety, goodwill, and organisational reputation, reduced environmental degradation, and decreased liabilities. Structural integrity management of pipelines requires continuous data collection using inline inspection technologies as part of the risk-based assessment for preventative maintenance. [4] points out that the first few years after commissioning pipelines are relatively safe to operate and reliable to use; however, with time, the structural integrity decreases due to various factors. After some time, a pipe wall will develop more significant or minor flaws during its economic service life; these types of defects require fit-for-purpose assessment. Further, research studies on pipe structural integrity show that corrosion is a primary root cause for failures and is most challenging to detect. [5] claims that corrosion defects generally cause approximately 42% of pipeline failures. [6] argues that about 50% of the recorded significant pipeline failures between 1980 and 2006 were primarily due to compromised structural integrity associated with corrosion. Many regulations and standards i.e., ISO 19342-2-2019, NACE SP 0102:2010, SANS 347, EN 16348, ASME B31 G, BS 7910, and PD 8010-4 support the use of inline inspection technologies to evaluate fitness-for-purpose (compare). Compared to other techniques, inline inspection technology provides effective and efficient ways to inspect longer pipe lengths within a reasonable period [7].

Inline inspection technology aims to identify and detect unwanted anomalies on the pipe wall and categorise defects according to the condition grading of 1 – 5, where one (1) is "very good," and five (5) is unserviceable [8]. To be particular about the structural integrity, it is the pipeline owner's responsibility to conduct structural health condition monitoring to identify defects and flaws or significant damage to the pipe before failure [4]. Rehabilitation and renewal are the most critical aspects of the organisational maintenance decision; hence, knowing the pipeline's structural integrity becomes essential. [9] maintains that any inline inspection technology will benefit the pipeline owner or operator by increasing confidence and reducing maintenance costs.

Similarly, [10] suggests that reducing 20% to 30% of the operational cost can be achieved through optimisation efforts. [11] firmly believes that pipeline defects result in additional maintenance costs and could lead to fatal catastrophic failures, such as the case in Taiwan where 27 people succumbed to the disastrous pipe failure, and about 286 people were injured. Inline inspection technology allows the pipeline owners to evaluate simultaneously and trade-off multiple drivers, such as avoiding unintended reactive maintenance costs, reducing pipe bursts, and improving performance, reliability, and availability [9]. Knowing the root cause of failure would enable the development of rehabilitation or maintenance strategies to avoid repeat pipe failures.

II. LITERATURE REVIEW

[12] indicated that the goal for using ILI technology is to determine the structural condition of pipelines to support decision-making about possible preventative or remedial action to ensure desired service levels. The increasing trend in managing structural integrity of pipelines using inline data has proven to be a quicker and more effective way of doing analysis and decision-making regarding refurbishment or replacement of corroded pipelines to reduce maintenance costs and minimise downtime. [13] claims that periodic pipeline maintenance was minimal in the past; the structural integrity of a pipeline would deteriorate in such a way that by the time pipeline failure occurred, it was either impossible to repair or refurbish the affected section or entire pipe length.

Inline inspection technologies are now extensively used to detect and inspect various types of pipe defects and flaws. Pipeline structural integrity challenges are now calling on pipeline operators to prioritise inline inspection techniques as part of structural health condition monitoring, thus due to increased regulatory and economic constraints associated with worldwide ageing pipeline infrastructure [7]. [8] states that an organisation must have precise knowledge about its structural condition and pipeline performance. In other countries, pipeline monitoring regulations demand periodic pipeline monitoring systems for the structural integrity of pipelines; thus, pipeline integrity assessment and the fitness-for-purposes condition is mandatory [7].

[14] states that pipeline owners invest approximately \$2.2 trillion annually in corrosion monitoring technologies. [6] indicates that the budget for corrosion monitoring technology in the United States of America increased by more than \$1 trillion in 2012, accounting for approximately 6.2 percent of GDP. [3] emphasises that the development of the Pipeline Integrity Management (PIM) programs must be part of maintenance strategies. [15] defines Pipeline Integrity Management as the process of evaluating and mitigating pipeline risks to minimise the likelihood of pipe failure and its consequence.

Besides, [15] emphasises that pipeline integrity management must have supporting functions such as condition assessment policies, including corporate objectives/guidelines and maintenance procedures, to ensure effective pipeline integrity management. Many inline inspection technologies are now available on the market with four measures that characterise the performance of each technique: locating, detecting, identifying, and accuracy [1]. Besides, [16] argues that detailed structural integrity assessment for longer pipelines has limitations on selecting inline inspection evaluation tools due to vertical bends and varying gradients along the pipeline route. [17] firmly believe that a possible way to determine the extent of internal corrosion is to do external excavations and examine the wall thickness.

The complexity of unsystematic corrosion on metal structures has made corrosion prediction over the design useful life of pipeline assets challenging to predict. [1] expanded the research on various inline inspection technologies currently available in the market as follows:

- Magnetic Flux Leakage (MFL)
- Guided Ultrasonic (UT)
- Eddy Current Testing (ET)
- Ultrasonic Testing for crack detection
- Electromagnetic Acoustic Transducer (EMAT)

Furthermore, [1] compared the performance of each inline inspection technology as follows:

TABLE 1: INLINE INSPECTION TECHNOLOGY COMPARISON

ILI tool type	**Cracks**	**Metal loss (due to corrosion)**	**Metallurgical changes**	**Geometry changes**	**Others (Weld characteristic, etc.)**	
Ultrasonic	Y	Y	N	N	S	
Magnetic flux leakage	N	Y	Y	S	S	
Electromagnetic acoustic transducer	Y	N	N	N	S	
Eddy current Testing	Y	N	S	N	S	

Y: The ILI tool can detect this type of flaw.

N: The ILI tool cannot detect this type of flaw.

S: Some ILI tools can detect this flaw while others cannot.

[18] recommends that it is the inline inspection operator's responsibility to select the inline inspection tool based on the pipeline owner's goal and objective for the inspection. [19] suggests that the corrosion engineer or pipeline inspector must be familiar with the distinctiveness of various corrosion defects and the associated constraints on the inline inspection tools selection. [1] defines detection as the capability to detect the metal flaw when the probability of detection must be over 90%. [20] claims that predicting the extent of the damage on steel pipes with gouges or defects can be challenging. Also, [21] indicated that there is limited literature on dent depth influence on the ultimate limit state of pipelines or burst pressure. Plain smooth steel pipes with dent depth up to 8% of the outer diameter do not impact the burst strength of the assessed pipeline. However, some authors argue that a plain dent with dent depth up to 24% of the pipe outside diameter (OD) has minimal effect on the burst strength of steel pipe.

[22] firmly believes that if the dent depth on a weld exceeds 2% or 4% of the pipe outside diameter (OD), it compromises the pipeline's structural integrity, and immediate replacement of the affected pipe segment is required.

[2] recommends emergency replacement when a steel pipe has lost 80% of its original wall thickness. [23] support the view that replacement is required if the pipe segment has a

corrosion depth of 80%. [24] challenges that the pipe failure criterion depends on a critical corrosion depth, usually 85% of the original pipeline wall thickness. Further, [23] claims that if the corrosion depth is less than or equal to 20% of the actual wall thickness, the pipe segment is safe to operate. [25] emphasises that "in no case shall pipe wall thickness be less than 1.8mm." [1] maintains that the most deterministic methods to evaluate the inline inspection data for structural integrity assessment are: ASME B31G, modified B31G, RSTRENG, SHELL92, SAFE, DNV-RP-F101, CPS, and PCORRC.

[8] states that the benefits of knowing the structural integrity of pipelines are:

- Avoidance of premature failure.
- Accurately predict future budget requirements for periodic condition assessment.
- Amend operating philosophy, maintenance plan, and rehabilitation strategies based on existing pipe material strength.
- Develop a risk management plan associated with pipe failure and mitigation of the consequence of failure.

[26] claims that pipeline owners benefit from accurate detection, identification, sizing, and locating of pipe defects: (1) benefit (saving) realised by correctly detecting critical defects before pipeline burst or rupture; and (2) correct accurate 3D sizing of the detected defect(s) (accurate failure prediction). [27] states that preventing leaks or pipe ruptures is more than or equivalent to avoiding these possible expenses.

III. Research Methodology

This study uses a quantitative research method, and the nature of the research is experimental. The methodology in this paper focuses on an 800mm diameter with 8mm wall thickness and X42 steel pipe material. The pipeline owner is treated confidentially; therefore, the study area is not indicated. At the same time, it also only considers the Guided Ultrasonic inline inspection tool. A total of three corrosion monitoring locations are selected based on % IR values from the direct current voltage gradient. This study considers only one corrosion monitoring site. The proposed methodology utilises the deterministic codes and standards; ASME B31G, DNV, RSTRENG, PCORRC, and API 579 to analyse the data collected by the inline inspection tool. These codes characterise the surface defect in a longitudinal (axial) section of a defective pipe segment as parabolic form, as shown in Fig. 1. The defect area highlighted in grey is calculated $\frac{2}{3}\ d.l.$

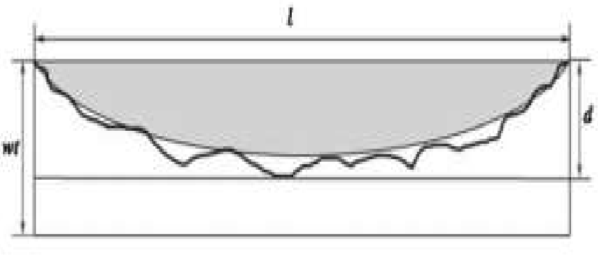

Fig. 1 Parabolic approximation of the surface defect in the pipeline longitudinal cross-section, as per B31G and DNV codes
Source:[26]

Where:

l is the maximum length of the defect along the pipe axis

wt is the pipe wall thickness

d is the maximum defect depth

Deterministic codes assess the extent of corrosion at different corrosion monitoring points. These codes are based on numerical supposition, rely on data that is often difficult and expensive to obtain, do not take account of the complexity of the corrosion rate process, and can only be applied to analyse collected data. [26] states that these deterministic codes use the semi-empirical criteria of the plastic fracture equation to calculate the remaining strength of a pipeline segment with the longitudinally oriented defect, as shown in equation 1.

$$\sigma_h = \sigma_f \frac{A_0 - A}{A_0 - AM^{-1}} = \sigma_f \frac{1 - \frac{d}{wt}}{1 - \frac{d}{wt.M}} \qquad (1)$$

Where:

σ_h is Hoop stress of the pipe segment with a single defect

σ_f is Yield stress

A_0 is $l.wt$ the initial length of the longitudinal cross-section of the damaged pipe segment.

l is the maximum length of the defect along the pipe axis

wt is the pipe wall thickness

$A = ld$ is the area of the defect in the longitudinal cross-section of the defective pipe segment

d is the maximum defect depth

M is a folias factor

B31G Code

[27] states the B31G code estimates that the surface defect in the longitudinal section of a defective pipe segment is in a parabolic form. The defect area highlighted in grey is calculated $\frac{2}{3}\ d.l.$

Equation (2) is Folias factor formula

$$M_1(\mathrm{t}) = \sqrt{1 + 0.893\frac{l^2}{D.wt}} \qquad (2)$$

Where:

M = folias factor

t = defect pipe segment at the time

D = pipe outer diameter

wt = pipe wall thickness

l = maximum length of the defect along the pipe axis

flow stress $\boldsymbol{\sigma_f}$=1.1Specified Minimum Yield Stress (SMYS).

$$P_f(\mathrm{t}) = \frac{2wt\ .1.1SMYS}{D} * \frac{\left(1 - \frac{2d(t)}{3\ wt}\right)}{\left(1 - \frac{2}{3wt.M_1(t)}\frac{d(t)}{}\right)} \qquad (3)$$

Where:

p_f(t) = failure pressure

t = defect pipe segment at the time

wt = pipe wall thickness

SMYS = Specified minimum yield stress

D = pipe outer diameter

d =internal diameter

M = Folias factor

$$p_f(t) = \frac{2wt\,(SMYS+68.95MPa)}{D}\;\frac{\left(1-\frac{0.85d(t)}{wt}\right)}{\left(1-\frac{0.85d(t)}{wt*M_2(t)}\right)} \tag{4}$$

Where:

p_f = failure pressure

t = defect pipe segment at the time

M = Folias factor

wt = pipe wall thickness

A. Sample and Data Collection

The Direct Current Voltage Gradient results indicate the extent of the corrosion defect. Based on the % IR value, corrosion monitoring locations with large (35 – 60%) to very large (>60%) coating defects are considered. The coating defect size generally characterises the criticality of the coating defect. The Guided Ultrasonic inspection technology measures the remaining wall thickness on identified corrosion monitoring location.

B. Results

Table 1 illustrates the inline inspection data collected on corrosion monitoring location using the Guided Ultrasonic tool. The measurements are taken at a 50mm interval.

TABLE 2: WALL THICKNESS MEASUREMENTS

Interval (mm)	MEASURED WALL THICKNESS (mm)									
50	7.1	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.6	7.6
100	6.9	6.9 5.94	6.9 5.94	7.1 5.94	7.4	7.4	7.4	7.6	7.3	7.6
150	7	6.9 5.94	6.9 5.94	7.1 5.94	7.4	6.5 4.93	6.4 4.93	7.5	7.4	7.4
200	7.1	7.8 5.94	7.7 5.94	7.7 5.94	7.5	7.6	7.5	7.5	7.4	7.5
250	6.8	7.7	7.7	7.7	6.7	6.6 3.31	6.9 3.31	7.4	7.4	7.4
300	6.7	7.7	7.7	7.7	6.9	6.6	6.5	4.4	4.4	4.9
350	6.9	7.5	7.3	7.1	6.8	5.9 3.14	5.0 3.14	4.4	4.4	4.9
400	7.4	6.9	7	7	6.7	6.4	6.4	3.1	3.1	3.3
450	7.3	7.1	7.5	6.9	6	6.1	6	7.7	7.7	7.7

The exception is areas where the original wall thickness has significantly reduced by 61.25%, with 3.1mm remaining wall thickness. These results show that the inspected pipe is indeed subjected to metal loss due to corrosion.[8] developed a condition grading system to evaluate the criticality and the extent of corrosion defects. Table 2 shows varying condition grading results based on the remaining wall thickness.

TABLE 3: CONDITION GRADING SYSTEM

Ranking	Description of Condition
1	Condition grading 1 characterises Very Good condition (Only regular maintenance required).
2	Minor Defects Only (Minor maintenance required (5%)
3	Maintenance Required to return to an acceptable level of service (Significant asset maintenance required (10-20%)
4	Requires Renewal or Upgrade (20 - 40%)
5	Over 50% of asset requires replacement

C. Data Accuracy and Assurance

The legitimacy of measurements directly depends on the correct selection of the inline inspection tools and their accuracy [28]. Besides, each ILI tool has its respective strength and weakness. [28] indicated that after completing the inline inspection, a minor percentage of the detected pipe wall imperfection is verified by doing another set of measurements. Guided Ultrasonic tool results were within the tool specification for pipe defect detection capabilities, confidence interval, accuracy, minimum detection levels, and detection thresholds.

IV. DATA ANALYSIS

[29] developed a flow chart for flaws or damage mechanisms. The pipeline flaw or damage mechanism on Pipeline A is Corrosion. As shown in Table 4, deterministic methods: DNV, RStreng, PCORRC, and ASME B31G evaluated the maximum allowable operating pressure in all corrosion monitoring locations as per Table 2. These methods showed different safe operating parameters.

Furthermore, the PCORRC only takes the maximum length, and the full depth and API RP579 determined the fitness for service. Similarly, pipeline A material is as per the API 5L specification; therefore, data analysis uses API RP579 and ASME 31G (approved manual for determining the remaining strength of the corroded pipelines). [30] maintains that the ASME B31G code for failure pressure prediction using the area method (RSTRENG) has significantly benefited pipeline owners by reducing unnecessary pipe repairs. The API RP579 is the method that predicts the failure pressure closest to the burst pressure.

TABLE 4: RESULTS OF WALL THICKNESS ANALYSIS

METHOD	Max. Safe Pressure (MPa)	Burst Pressure (MPa)	F-Safety
PRCI - RSTRENG - Effective Area	2.29	3.82	4.778
PRCI - RSTRENG - 0.85DI	2.06	3.44	4.301
PRCI - ASME B31G	1.23	2.05	2.568
DNV	2.45	4.09	5.109
API RP 579, Level 1	1.44	2.40	2.994
PCORRC	2.44	4.06	5.076
SHELL	2.00	3.33	4.165

Fig. 2 shows a graphical presentation of the remaining wall thickness measurements. This graph clearly shows the extent of the metal loss, with some sections nearing the 80% line being the most critical area for pipe safe operating conditions. The minimum and the maximum measured metal loss are 21.8% and 61.25%, respectively. However, 61.25% is lower than 80%, regarded as a critical failure operating threshold, and 21.8% is higher than the 20% threshold, which is considered acceptable for safe operating pressure. Based on data analysis results, the inspected pipe segment with 61.25% has exceeded the design stresses of 50 and 60%.

Furthermore, the results from ASME B31G and API RP579 were the closest to the failure pressure (burst pressure). In this case, the thinned wall will result in performance limits such as excessive deformation and leaks. Besides, to avoid water losses or unintended pipe failure, it is recommended to regulate operational philosophy.

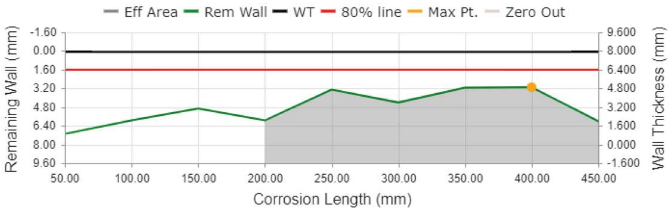

fig. 2: corrosion profile pit depth

V. Discussion

From the identified coating defects, metal loss due to corrosion was observed. [1]indicated that pipe failure stress due to corrosion defect can be expressed as a function of shape and the size of the defect and pipe geometry, and the material properties, such as ultimate tensile strength and specified minimum yield strength. A pipeline failure caused by a corrosion defect can occur when the burst pressure is lower than the maximum allowable operating pressure (MAOP), or the depth of defect reaches the critical operational threshold of 80%.

The operational threshold describes the minimum acceptable operative conditions that the pipe must withstand internal pressure. Also, if the corrosion depth is less than or equal to 20% of the original wall thickness, it is concluded that the segment is acceptable for service. Though the maximum metal loss is less than 80%, which is regarded as “high risk” due to the potential pipe failure, the inspected pipeline comprises X42 steel material with a specified minimum yield strength of 289.6MPa and design stress of 60%. In this case, the maximum measured corrosion defect is 61.25%, exceeding the allowable design stress of 60%. The stresses developed in this pipe segment due to service loads might exceed the elastic limit and thus result in permanent deformation. The failure probability of an engineering system is when the allowable limit state is exceeded.

[26] indicates that the time reached of a critical state by a “leak criterion” is the time required for a defect under the estimated corrosion rate to measure the depth of 60, 70, or 80% of the pipe wall thickness. Therefore, sections with a measured corrosion depth of 61.25% will ultimately leak. Based on these results, the inspected pipe segment has a condition grading of 3; pipeline intervention services are required to maintain the structural integrity.

VI. Limitations

The metal loss analysis using deterministic methods requires corrosion rate per for the inspected pipe segment. In this case, the year in which the corrosion started remains unknown.

[31] recommends a point-to-point method to obtain an annual corrosion rate. This method considers the number of years of a pipeline in service. Also, the year in which foreign the infrastructure such as cathodically protected gas pipelines and railway lines were commissioned is unknown. From the results, it is evident that the foreign infrastructure affects the structural integrity or impacts negatively on inspected pipe segments.

In this case, to obtain the corrosion rate, a point-to-point method is considered. The calculated corrosion rate of 0.153% over the economic service useful life of 32years using the point-to-point method to analyse the data might be incorrect, thus resulting in overestimating or underestimating the remaining useful life of the inspected pipe segment.

Furthermore, incorrect indicative remaining useful life will affect the replacement pipe schedule and thus will lead to reactive maintenance. Additionally, the proposed corrosion measuring device to capture live data or real-time data will assist in monitoring wall thinning due to corrosion.

VII. Future Research

The known corrosion growth rate allows for predicting the corrosion condition of the pipeline in the future. Although the corrosion growth rate can be used as an indicator of the corrosion rate over the economic service useful life of the steel pipe when the extrapolation is done, the uncertainties can be significant as the corrosion rate per year is unknown. These uncertainties can be minimised by developing proper corrosion growth rate models that best suit the environment and pipeline conditions. In general, determining the correct corrosion rates is very important. Low corrosion rates could lead to a leak or rupture of pipelines, while high corrosion rates could result in an unnecessary assessment of pipelines.

VIII. Conclusion

Many studies in the broader literature have examined the importance of inline inspection tools. Inline inspection tools provide accuracy, confidence, and quantitative measurement capabilities, allowing for a less conservative assessment. However, Corrosion rate per annual is meaningful data for structural integrity analysis; however, using a formula to obtain the corrosion rate per annum might present inaccuracies.

Though pipeline industry regulatory requirements emphasise the management of pipelines through practical reliability engineering, maintenance, and design, inline inspection technologies are still regarded as a burden of expenses, especially in the water industry. Although inline inspection tools have proven to be effective in collecting data for structural integrity analysis, a need to develop a corrosion measuring device compatible with other pipeline monitoring systems exists.

Currently, when the maintenance budget is insufficient for condition-based monitoring, the most used method to assess the leaks is pipe patrolling. This type of assessment usually does not add much value as some leaks do not surface. In most cases, pipe gradient and vertical bends restrict the inspection resulting in other pipe segments not being inspected. Also, some technologies require insertion and extraction points during inspection; however, the proposed device will be attached to the pipe wall during pipe laying, and a budget for excavation will not be required. Further, congested pipe servitudes by other infrastructure services restrict the required excavations for direct inspections.

The compromised structural integrity of steel pipe often leads to failure that significantly impacts the environment and social and economic impact. Despite all maintenance activities performed in the pipeline industry, unexpected pipe failures will continue to occur. Pipeline failure due to compromised structural integrity is a global crisis; the impact of these incidents can be minimised by monitoring. This will ensure that pipeline infrastructure is retained in the "available state" to perform its intended function under given operating conditions.

IX. RECOMMENDATIONS

The structural integrity of the steel is evaluated on the principle of pipe performance, such as leaks and longitudinal deformation. Inline inspection technologies have proven to be effective in collecting data to detect anomalies and defects that might affect performance. Though ISO 19342-2 2019 recommends complete life-cycle integrity management, corrosion remains challenging to monitor. Literature suggests different acceptable corrosion rates per annum; however, these rates might not be applicable in some cases as wall thinning due to corrosion differs from one environment to another.

The available inline inspection technologies require a technology operator to do physical measurements. When this intervention is not done regularly, defects will continue to grow, and by the time they are detected, it is already too late. It is, therefore, recommended that a remote monitoring corrosion measuring device be developed to capture the live data. This device must be linked to other monitoring systems, and data be integrated into the hydraulic software, Geographical Information System (GIS), including the SCADA and Maximo.

When manufactured correctly as per the API 5L specification, steel pipe has good material strength that can withstand environmental conditions; however, a good coating system acts as primary protection, and cathodic protection systems are required. The device will assist the cathodic protection team in identifying immediate changes in pipe potentials.

The benefit of using or installing a corrosion measuring device will be realised by correctly detecting critical defects before the pipeline burst. Also, this device will assist in capturing the correct 3D sizing of the detected defect. Pipeline owners incur additional expenditures on legal liabilities due to pipe ruptures, and these incidents ruin pipeline owners' reputations.

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