In the oil and gas industry, maintaining the integrity of production equipment is critical to ensuring the industry's sustainability. Failure to maintain the integrity of production equipment can result in financial losses for the business. The management of production equipment nearing the end of its design life faces an increasing cost of Inspection, Maintenance, and Repair (IMR). As a result, a strategy to improve the efficiency of IMR is essential. Recent IMR management practices include predictive Risk-Based Inspection (RBI), which is more efficient than Time-Based Inspection (TBI). The research intends to evaluate the 28-year-old subsea sales gas pipeline using API 581 standard quantitative methodology by utilizing the Inline Inspection (ILI). Specifically, the study focuses on measuring the Probability and Consequence Failure of inspected pipelines. The inspection interval is determined based on the minimum allowable thickness. The risk calculation indicates that 12 pipeline segments are at a medium risk level (3 segments, 1D and 1E, and 2C). The remaining nine segments remain at lower risk (1C). Based on the result, segment nine is accepted as the highest PoF value of 1.04E-4 failures per year due to high depletion values due to the higher CoF value at the leak location. The calculation of the inspection interval indicates that the forthcoming Inspection will be due 20 years post the previous assessment. Another method using the Estimated Repair Factor (ERF) thickness limit approach produces the same results. However, assessment using ASME B31.8S provides different results of 10 years intervals when using the same ILI inspection method. This work can be used as a standard guideline to assess the risk of pipelines over a decade in service

Keywords: risk-based Inspection, sales gas pipelines, ILI, Risk of Failure

UDC 622
DOI: 10.15587/1729-4061.2023.277256

DEVELOPMENT OF RISK-BASED INSPECTION OF 28-YEARS-OLD SUBSEA SALES GAS PIPELINES TO SUPPORT THE ENERGY DEMAND

Johny Wahyuadi Soedarsono
Corresponding author
Doctor of Engineering, Professor*
E-mail: jwsono@metal.ui.ac.id
Arie Wijaya
Bachelor of Science, Bachelor of Engineering, Master of Engineering*
Taufik Aditiyawarman
Master of Science, Doctoral Degree Student**
Agus Paul Setiawan Kaban
Master of Engineering, Graduate Student*
Rini Riastuti
Doctor of Engineering, Senior Lecturer*
Rizal Tresna Ramdhani
Bachelor of Science, Bachelor of Engineering,
Master of Engineering, Senior Engineer*
Ayende
Doctor of Engineering
Department of Mechanical Refinery Engineering
PEM Akamigas
Jalan Gajah Mada, 38, Cepu, Blora, Jawa Tengah, Indonesia, 58315
*Prof Johny Wahyuadi Laboratory**
**Department of Metallurgical and Materials Engineering
Universitas Indonesia
Kampus Baru UI Depok, Jawa Barat, Indonesia, 16424

Received date 15.02.2023
Accepted date 18.04.2023
Published date 28.04.2023

How to Cite: *Soedarsono, J. W., Wijaya, A., Aditiyawarman, T., Kaban, A. P. S., Riastuti, R., Ramdhani, R. T., Ayende (2023). Development of risk-based inspection of 28-years-old subsea sales gas pipelines to support the energy demand. Eastern-European Journal of Enterprise Technologies, 2 (3 (122)), 17–27. doi: https://doi.org/10.15587/1729-4061.2023.277256*

1. Introduction

The oil and gas industry provided an average of 18.2 % of non-tax state income per year between 2014 and 2020, as reported in [1]. Currently, the Oil and Gas Cooperation Contractors operate 199 work areas, of which at least 40 have functioned for more than 30 years, exceeding the design life specified at the production time. Asset Integrity Management (AIM) is used to manage production equipment. AIM includes the Inspection, Maintenance, and Repair operations designed to ensure the continuity of the production process, prevent process safety issues, and minimize losses on corporate assets [2]. Additionally, the strategy is an effective technique for enhancing the effectiveness of inspections through planning and risk assessment [3, 4].

Subsea pipelines are underground pipelines that transmit oil and natural gas output from one production platform in offshore facilities to another or to receiving terminals on land. According to a survey conducted by the Pipeline Hazardous and Material Safety Administration (PHMSA), pipeline breakdown occurrences over the previous decade have reached 12,507 cases, resulting in a loss of nearly USD 10 million, including an average of 14 fatalities and 59 injuries to employees [5]. Protecting the asset to maintain the operational and functional industry's activity is critical.

Production management facilities exhibit several unique issues due to Natural Decline and increased Inspection, Maintenance, and Repair (IMR) expenses beyond their design life. Maintaining the integrity of manufacturing equipment near the end of its design life demands a unique strategy since changes in operating parameters and fluids throughout operation might affect the equipment's failure. Equipment failure results in losses and hazards, giving the business management ample time to maintain a safe work environment. At the same time, it is beneficial to ensure production continuity, hinder excessive financial loss, and comply with existing norms and regulations.

A company must reduce the hazard and impact of the risk posed in the event of a failure by implementing preventive steps to ensure that the pipeline's operation is maintained and safe in a more effective manner. The Risk-Based Inspection (RBI) method is one strategy that is thought to be effective in maintaining pipeline integrity [6, 7]. Compared to the Time-Based Inspection approach, RBI is a method for developing an inspection plan based on the probability of failure during equipment operation and the impact if a failure occurs.

Numerous studies have been conducted on applying the RBI method for arranging pipeline inspections. The publication [8] shows that RBI is suitable for assessing the corrosion of underwater oil pipelines using pipe thickness division by burst pressure as a PoF classification. A recent study [9] argues that data management to historical data in assessing pipelines should not be oversight despite the utilization of magnetic flux leakage (MFL) testing, ultrasonic testing (UT), electromagnetic acoustic technology (EMAT), and eddy current testing (EC). While the research [10] claims that autonomous underwater vehicle (AUV) becomes an essential tool for locating and determining the leak area of submarine pipelines. On the other hand, the work [11] evaluates the reliability of equipment using the degradation model of corrosion using the value of corrosion rate internally and externally. The work [12–14] argues that inhibitor protection can help to reduce the impact of corrosion while preserving the environment, which is essential to lower the risk of pipeline failure. Therefore, it is essential to measure the risk of pipelines that deliver sales gas to prevent a severe catastrophic incident.

2. Literature review and problem statement

The paper [15] shows that the leak from an external force and defects in the girth weld are two root causes of failure for the leak in the sales gas of the company. Implementing quantitative risk assessment focuses on developing a strategy to increase the integrity assessment of sales gas pipelines. The study [16] shows that not merely the preventive action required but also the presence of black powder exhibits fatality towards the integrity and operation of natural gas transmission. It is important to note that sales gas pipelines and their corresponding risk analysis are an inherent extension measurement to monitoring gas delivery safety. In the research, the detection device detects an anomaly by sending a microwave signal, which has a detection precision of nearly 93 %.

The reason to measure the risk of sales gas pipelines is to ensure the timed delivery of hydrocarbon to meet the energy demand. It is common practice to use risk-based Inspection to evaluate the risk of pipelines aging related to their probability of failure (PoF) value as a function of time [17]. The study includes measuring mechanical properties to explain the behavior of aging pipelines. With this in mind, monitoring material degradation due to corrosion is critical. On the other hand, the shortcoming assumption that corrosion is uniform throughout the pipelines provides an analytical method to prioritize the corroded material's reliability. Therefore, the probability of corroded pipeline failures becomes a primary factor in considering types of mitigation [18]. In this instance, the probability analysis of the rupture and local burst remains critical since the corrosion effect decreases the pipelines' wall thickness. In the other publication, the analysis of PoF and CoF is another measurement to obtain the actual risk of pipelines, including assessing 5C or medium-high risk [19].

This study aims to analyze PoF and CoF using inspection data obtained through Inline Inspection (ILI), which includes assessing 5C or medium-high risk from one of the pressurized facilities. The uninspected pipelines may be an inherent risk due to fatigue, which has been in service for 28 years. However, difficulty arises when selecting proper tools to measure the risk and the actual method to capture the risk level of inspected pipelines. An option to overcome the relevant difficulties can be developing a Risk-based inspection using a risk matrix and generating data through inline Inspection as reported by [20]. The study [21] shows that the RBI is essential to replace the existing time-based Inspection.

The pipeline is at risk of failure when proper inspection planning is not implemented. The American Petroleum Institute (API) has recommended risk-based Inspection (RBI) planning depending on the risk level of the pipeline in the API 581 standard [22]. As a result, this study focuses on determining inspection intervals required by the API 581 standard using a quantitative calculation method against the 28-year-old subsea sales gas pipeline. Thus, inspections become more efficient and cost-effective while still meeting the requirements for operational safety.

However, the strategy is characterized by the difficulty to measure the immediate risk of pipelines. A recent generation of Inline Inspection (ILI) employs magnetic flux leakage (MFL) detectors to gain the defects in the internal and external surfaces of pipelines [23]. In particular, the intelligent pigging of MFL manages to obtain the data related to the crack located in the axial and circumferential direction. Acquiring essential information related to pipeline defects showcases the importance of measuring and mitigating the risk.

A few studies report and implement the RBI, which correlated to the result of ILI inspection. The work [24] implements RBI as a primary tool to prevent unplanned shutdown by ranking the risk based on all static equipment, inspection activities, and their optimization. The study shows the RBI is in place of time-based Inspection to gain the priority of Inspection based on the risk assessment. On the other hand, the RBI entails calculating the Probability of failure (PoF) and Consequence of failure (CoF). Several standards have been implemented to measure the risk, including DNV RP F101 [25]. The document provides practical recommendations for corroded pipeline assessment based on internal pressure loading and longitudinal compressive stress. It can be stated that ASME B31 G [26] governs the strict implementation of the relation between the size of defects and their internal pressure, which may lead to leaks or failed materials. As illustrated in Shell-92 [27], the standard code of Shell-92 considers the corrosion assessment to prioritize the burst pressure of corrosion defects. It relies on the average depth and the stress flow of pipelines. Compared to the rest of the standards, the British Standard of BS 7910 [28] outlines the criticality of the existing and new integrity of the non-destructive testing method to obtain the acceptance level of inspected pipelines.

The PoF and CoF assessments conducted against these multiple criteria produced similar findings.

As a result, risk mitigation is required to minimize the risk through inline Inspection. This study aimed to analyze PoF and CoF using inspection data obtained through Inline Inspection (ILI), which includes assessing 5C or medium-high risk. Moreover, the object of this study is entire pipelines that remain in their service life for 28 years. The pipeline is at risk of failure if proper inspection planning is not implemented. The American Petroleum Institute (API) has recommended risk-based Inspection (RBI) planning depending on the risk level of the pipeline in the API 581 standard. As a result, this study focuses on determining inspection intervals required by the API 581 standard using a quantitative calculation method against the 28-year-old subsea sales gas pipeline. Thus, inspections become more efficient and cost-effective while still meeting the requirements for operational safety. All this allows us to argue that it is appropriate to conduct a study to unveil the potential risk-based Inspection in uninspected sales gas pipelines.

3. The aim and objectives of the study

The study aims to determine the risk of failure of uninspected sales gas pipelines, which corresponds to their applicability in measuring the probability and consequence of failure.

To achieve this aim, the following objectives are accomplished:

– to determine the most severe segment of pipelines with the highest thickness loss;

– to assess the risk using a risk-based inspection method to obtain the highest segment corresponding to their probability and consequence of failure;

– to predict the upcoming inspection schedule of the pipelines based on the current results.

4. Materials and methods of research

4. 1. Materials and hypothesis of the work

The research object is the subsea pipelines (Carbon Steel API 5L X60) that deliver sales gas from the processing platform to onshore receiving facilities (ORF). The specifications of the pipelines are shown in Table 1.

Table 1

Pipeline specifications

Name	Description
Type of Equipment	Pipelines
Service Fluid	Natural Gas
Year Built	1993
Design Standard	ASME B31.8
Materials	Carbon Steel API 5L X60
Dimension	219.08 mm (OD)×14.275 mm (WT)× ×49.380 mm (L)
Corrosion Control	Coating and Sacrificial Anode
Safety Device	2 Pressure Safety Valve (PSV)
Design Pressure	91.39 kg/cm g (1,300 psig)
Design Temperature	93.33
Design Life	30 years
Operating Pressure	25.31 kg/cm g
Operating Temperature	32.22

According to Table 1, the natural pipelines have been bound to ASME 31.8 where the primary corrosion control is carried out by implementing the coating and sacrificial anode. It can also be noted that the pipeline is categorized as aging pipeline with considerate operating pressure.

On the other hand, it can be predicted that the inspected pipeline will have variation in terms of PoF value due to thinning. Due to dissimilar material corrosion responses, this assumption can be classified from multiple pipeline risk segmentation. Based on Table 1, it can be assumed that the material would have a moderate risk level due to corrosion mitigation of cathodic protection and coating.

4. 2. Methods

4. 2. 1. Segmentation of pipelines

In this work, the segmentation is classified as static or dynamic. Static segmentation divides the pipe every mile or as the valve component determines. By contrast, dynamic segmentation divides pipes into unequal or unknown length segments for each component [8]. The distribution pipe is segmented in this study using a combination of static and dynamic segmentation based on length and location. The sales gas pipelines were divided into 11 segments, according to Fig. 1.

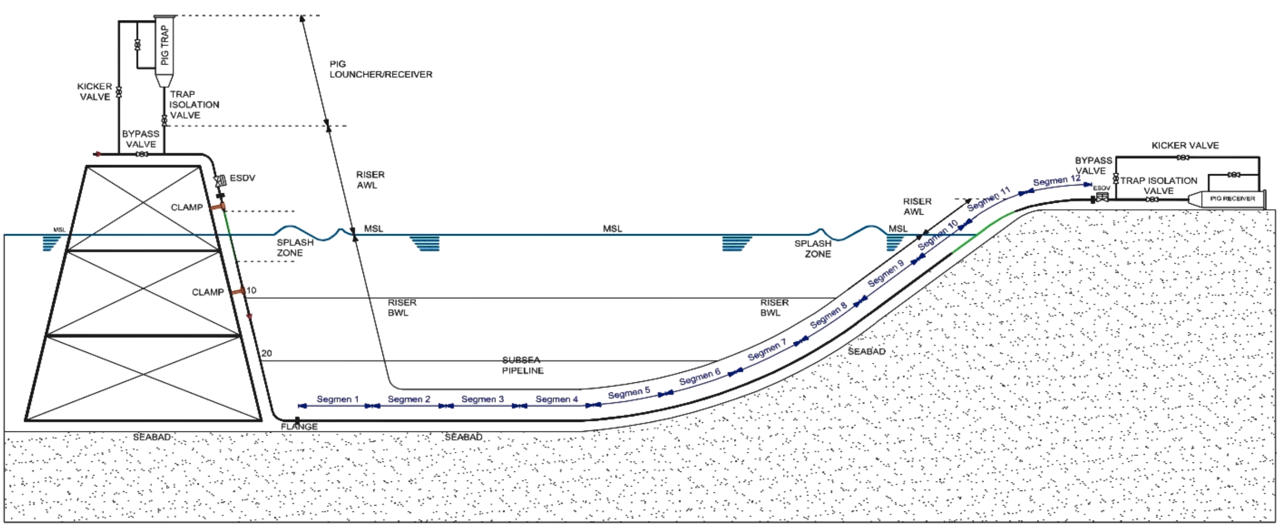

Fig. 1. Segmentation of pipelines risk analysis

The pipeline component was risk-assessed, from subsea part J-pipes below the offshore platform to onshore pipe flanges connected to the pig receiver at the end of the pipeline's boundaries. Segmentation divided the pipeline's approximately 5,000 meter length into segments 1 to 9 and was adjusted for length in segments 11 and 12 as they approach and enter the Onshore Receiving Facilities (ORFs) with varying consequence values.

4. 2. 2. Risk-Based Inspection

The inspection priority and manage the Inspection by focusing inspection and maintenance resources on equipment with greater risk. This study uses the RBI methodology based on API 581 for risk assessment of sales gas pipelines. API 581 has been accommodating the risk target concept for inspection planning. Risk is calculated using inspection data, time-dependent, and the result is more precise than with the qualitative approach [29]. Compared to qualitative risk assessment, it provides an objective analysis, reflecting not only on an expert judgment [30]. Therefore, such an approach will likely be audited by an external body. In the RBI methodology, the risk as a function of time is a combination of the Probability of Failure (PoF) and the Consequence of Failure (CoF), as indicated in (1) [7]:

$$\{Risk = PoF \times CoF\}. \tag{1}$$

In the above equation, PoF and CoF are the Probability and Consequence of Failure as a function of time. The Probability of Failure is calculated based on (2) [7]:

$$\{PoF = GFF \times F_{MS} \times D_{f(t)}\}. \tag{2}$$

In the above equation, *GFF* stands for Generic Failure Frequency and is a probability of failure developed for specific component types based on extensive population data and does not include the effect of specific damage mechanisms in the component. The recommended value of Generic Failure Frequency was taken from API 581. F_{MS} is a factor in the process safety management system. This factor results from evaluating a facility or operating unit management system that affects plant risk. A maximum possible score (*pscore*) as recommended by API 581 is 1000 and converted to F_{FM} using (3) and (4) [7]:

$$\left\{pscore = \frac{score}{1000} \times 100\,\%\right\}, \tag{3}$$

$$\{F_{MS} = 10^{(-0.02 \times pscore + 1)}\}. \tag{4}$$

D_f is a damage factor determined based on relevant active damage mechanisms at the process service to the constructed materials and inspection techniques to quantify the damage. D_f is used to modify the industry *GFF* and make it specific to the component under risk evaluation. Damage factors are calculated based on the damage mechanism using (5) [7]:

$$\left\{\begin{matrix} D_{f(t)} = D^{thin}_{f-gov} + D^{extd}_{f-gov} + D^{scc}_{f-gov} + \\ + D^{htha}_{f-gov} + D^{mfat}_{f-gov} + D^{brit}_{f-gov} \end{matrix}\right\}. \tag{5}$$

Based on (5), D^{thin}_{f-gov}, D^{extd}_{f-gov}, D^{scc}_{f-gov}, D^{htha}_{f-gov}, D^{mfat}_{f-gov}, D^{brit}_{f-gov} are Internal Corrosion D^{thin}_{f}, External Corrosion D^{extd}_{f}, Stress Corrosion Cracking (SCC) D^{scc}_{f}, High Temperature Hydrogen Attack (HTHA) D^{htha}_{f}, Mechanical Fatigue D^{mfat}_{f-gov}, and Brittle Fracture D^{brit}_{f-gov}. Only relevant damage mechanisms are included in the calculation damage factor; API 581 provides screening criteria for each mechanism based on equipment conditions, equipment fluids, environment, inspection results, and operating parameters.

The consequence of failures can be calculated either area-based or financial-based. The area-based consequence area is calculated based on phase and type of service fluid and equipment operating conditions. The analysis of the consequence area was conducted in two ways, level 1 for a single-phase fluid and level 2 when the fluid has two or three phases according to API 581. The consequence of area is calculated using (6) [29]:

$$\{A = a \times X^{b}\}. \tag{6}$$

Based on (6), *A* corresponds to the impacted area, and *X* is the continuous leakage rate and instantaneous leakage mass. The variables *a* and *b* are specified in the API 581 standard for the reference fluid of the API 581 standard handbook.

On the following note, the financial consequences were directly calculated by multiplying the affected area by costs per unit area and then adding this to the cost of business interruption and environmental cleanup costs. The value of financial consequences is determined by (7) [29]:

$$\{FC = FC_{cmd} + FC_{affa} + FC_{prod} + FC_{inj} + FC_{env}\}. \tag{7}$$

In the above equation, FC_{cmd} is the component damage, FC_{affa} is the Damage Costs to Surrounding Equipment in Affected Area, FC_{prod} is the Business Interruption, FC_{inj} is the potential injury, FC_{env} is attributed to environmental cost. A 5×5 risk matrix is used to present the calculated risk, as shown in Fig. 2. The location of each equipment segment on the risk matrix is determined based on the calculated PoF and CoF. The classification of PoF and CoF categories can be determined using the guideline in Table 2.

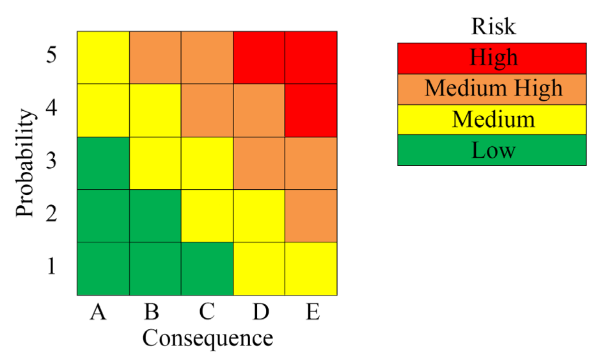

Fig. 2. Risk Matrix [29]

Table 2

Category of Probability of Failure (PoF) and Consequence of Failure (CoF) [1]

Probability of Failure (PoF)		Consequence of Failure (CoF)	
Category	Probability Range	Category	Financial Range (USD)
1	PoF≤3.06E-05	A	FC≤10,000
2	3.06E−05<PoF≤3.06E−04	B	10,000<FC≤100,000
3	3.06E−04<PoF≤3.06E−03	C	100,000<FC≤1,000,000
4	3.06E−03<PoF≤3.06E−02	D	1,000,000<FC≤10,000,000
5	PoF>3.06E−02	E	FC>10,000,000

In this work, the primary outcome of the risk-based Inspection is to determine inspection intervals using a particular inspection method. Instead of using a risk target, inspection planning was determined using a PoF target and compared with the remaining life from the corrosion rate calculation [29]. Using PoF as inspection planning has the limitation of ignoring the effect of CoF. CoF is considered dependent for the calculation of inspection planning. API 581 allows the determination of inspection planning by using the remaining life of equipment using the corrosion rate approaching. The remaining life of pipelines can be determined using (8) [31]:

$$\left\{RL=\frac{t_{rd}-t_{req}}{CR}\right\}, \tag{8}$$

where t_{rd} is attributed to the actual thickness from the inspection result and t_{req} is the minimum thickness required. In this equation, CR is the corrosion rate determined by the difference between the previous inspection thickness and the last inspection thickness by the tie interval of Inspection. Moreover, (9) shows the calculation of the corrosion rate (CR):

$$\left\{CR=\frac{t_{initial}-t_{actual}}{time_{(year)}\times t_{prev}\times t_{actual}}\right\}. \tag{9}$$

Based on (9), $t_{initial}$ and t_{actual} are the initial and actual thickness values (mm), while the time$_{(year)}$, t_{prev}, t_{actual}, are the time of observation, time of previous Inspection, and time of actual Inspection. All units are in a year.

Despite the value of CR, it is possible to interpret the Damage mechanism mainly by applying the total Damage Factor (D_f) of the external thinning and corrosion damage mechanisms occurring at different locations within the same segment.

(10) shows the calculation of D_f related to the segmentation:

$$\left\{D_{f-total}=\max[D_f^{thin},D_f^{extcorr}]\right\}. \tag{10}$$

According to (10), D_f^{thin} and $D_f^{extcorr}$ are the damage factors due to thinning and external corrosion.

5. Results of Risk-based Inspection of Sales Gas Pipelines

5. 1. Inline Inspection Data

Table 3 shows the value of the material loss, which is assumed to be constant, providing information on metal loss, depth, length location, and types of defect in the pipelines.

Table 3 shows that the risk evaluation data is obtained from the Inline Inspection (ILI) using Magnetic Flux Leakage (MFL) method. The ILI results indicate that the most significant metal loss occurs in segment nine at 41,330 meters from the Datum. Also, the starting thickness was reduced by approximately 34 % based on a nominal wall thickness of 14.28 mm (Table 3). It can be concluded that in segment 8, there was a significant loss of 20 % due to internal corrosion in 2007. However, the value was slightly lowered by 19 % in 2013.

5. 2. Risk-Based Inspection

5. 2. 1. Results of CO_2 and H_2S monitoring

The corrosion monitoring includes inspecting the CO_2 and H_2S content, as shown in Tables 4, 5. Table 4 shows the CO_2 partial pressure, which indicates the corrosion rate of the sales gas distribution before the analysis of RBI.

According to Table 4, the elevation of CO_2 partial pressure gradually increased over the four years of observation, with the highest value of 25.2 psi in 2020. CO_2 levels measured during sampling have increased since 2007, 2013, and 2020. The results of the CO_2 partial pressure classification analysis indicate that the corrosion rate falls into the «Corrosion May Occur» category.

On the other hand, Table 5 showcases the result of H_2S content monitored over the same observation period.

Table 3

Inline Inspection Data

Segmentation	Internal Corrosion				External Corrosion				Distance from Datum (m)	Length of Segment (m)
	2007		2013		2007		2013			
	Wall Loss (%)	Previous thickness (mm)	Wall Loss (%)	Actual thickness (mm)	Wall Loss (%)	Previous thickness (mm)	Wall Loss (%)	Actual thickness (mm)		
1	0	14.28	0	14.28	0	14.28	0	14.28	42.147–<5,000	4,957.853
2	0	14.28	0	14.28	0	14.28	0	14.28	5,000–<10,000	5,000
3	0	14.28	10	12.85	0	14.28	10	12.85	10,000–<15,000	5,000
4	0	14.28	10	12.85	0	14.28	0	14.28	15,000–<20,000	5,000
5	0	14.28	0	14.28	0	14.28	0	14.28	20,000–<25,000	5,000
6	0	14.28	18	11.71	0	14.28	0	14.28	25,000–<30,000	5,000
7	0	14.28	11	12.70	6	13.42	10	12.85	30,000–<35,000	5,000
8	20	11.42	19	11.56	6	13.42	10	12.85	35,000–<40,000	5,000
9	20	11.42	34	9.42	0	14.28	0	14.28	40,000–<45,000	5,000
10	0	14.28	10	12.85	0	14.28	0	14.28	45,000–<49,272	4,272
11	0	14.28	0	14.28	0	14.28	0	14.28	49,272–<49,283	11
12	0	14.28	0	14.28	0	14.28	0	14.28	49,283–<49,314	31

Table 4

CO_2 Corrosion Level Analysis

Year	CO_2 (%)	Partial pressure (psi)	Corrosivity Rate	Classification based on NACE SP-0106
2007	1.5	5.4	Corrosion May Occur	Partial Pressure CO_2>30 psi (usually corrosive)
2013	3	10.8	Corrosion May Occur	Partial Pressure CO_2 3–30 psi (corrosion may occur)
2020	7	25.2	Corrosion May Occur	Partial Pressure CO_2<3 psi (non-corrosive)

Table 5

H_2S Analysis of Stress Corrosion Cracking (SCC)

Year	H_2S (ppm)	Partial pressure (psi)	Corrosivity Rate	Classification based on NACE MR-0175 [2]
2007	0	0	No SCC tendency	Partial Pressure H_2S>0.05 psi can cause Stress Corrosion Cracking (SCC)
2013	7	0.00252	No SCC tendency	
2020	12	0.00432	No SCC tendency	

The results of the analysis of the H_2S content of the partial pressure are less than 0.3 KPa, indicating that it does not cause SCC according to the NACE MR-0175 classification (SCC). Fluid sampling results for H_2S impurities are consistent with Table 5.

5. 2. 2. Results of Probability of Failure Estimation

In this work, the probability of failure is calculated by multiplying the Generic Failure Frequency (G_{ff}), the Management System Factor (F_{MS}), and the Damage Factor (D_f) using (2), and their result is depicted in Tables 6–9. Table 6 shows the average failure frequency of equipment displayed in API 581.

Table 6

Generic Failure Frequency (GFF)

Equipment Type	Component Type	GFF as a function of hole size (failures/yr)				GFF_{total} (failure/year)
		Small	Medium	Large	Rupture	
Pipe	PIPEGT-16	8.00E-06	2.00E-05	3.06E-05	6.00E-07	3.06E-05

As can be noted from Table 6, the G_{ff} value for the 26-inch gas supply pipe is considered as the PIPEGT-16 component type. On the other hand, the management System Factor (F_{MS}) shows the significance of an adjusting factor that influences the mechanical integrity management system. Based on Annex 2A API 581 of the third edition (3) of 2016 or by implementing a 50 % threshold, the survey was conducted to obtain the F_{ms} score. The value is then converted to the p-score base. The result of (3) and (4) shows a p-score value of 50 %, while F_{MS} is 1. The Damage factor categorizes the risk factors into thinning, external damage, stress corrosion cracking (SCC), high-temperature hydrogen attack (HTHA), mechanical fatigue, and brittle fracture. In this work, D_f is induced by thinning and external damage, showcasing the corrosion rate category. The calculated corrosion rate compares the initial and inspected thickness observation, and their result is presented in Table 7.

Table 7 reports that the highest corrosion rate occurs in segment 9, which is related to short-term and long-term due to thinning. While implementing (10), the damage factor from the mechanism of external corrosion damage on segment 1 of the gas distribution pipe. Table 8 summarizes the calculation results for each pipeline segment.

Table 8 agrees well with the result of the corrosion rate due to thinning and external corrosion, which may indicate that the ninth segment has experienced the most significant corrosion process. In essence, Table 9 shows the value of PoF, which correlated to D_f, Gff, and F_{MS}.

The result of Table 9 is consistent with Table 8, which confirms that the same segment increases the risk of corrosion due to the presence of CO_2. In addition, the consequence of failure (CoF) is at a minimum level compared to the API 581 standard. Level 1 correlates to the result of the flowing fluid in place of the outer phase. Table 10 shows the calculated result of CoF.

Table 7

Corrosion Rate for Thinning and External Corrosion Damage Mechanisms

Segmentation	Corrosion Rate for Thinning		Corrosion Rate for External Corrosion	
	Short-term (mmpy)	Long-term (mmpy)	Short-term (mmpy)	Long-term (mmpy)
1	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00
3	0.00	0.00	0.24	0.05
4	0.24	0.05	0.00	0.00
5	0.00	0.00	0.00	0.00
6	0.10	0.09	0.00	0.00
7	0.26	0.06	0.10	0.05
8	0.05	0.10	0.10	0.05
9	0.33	0.17	0.00	0.00
10	0.24	0.05	0.00	0.00
11	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00

Table 8

Total Value of Damage Factor

Segmentation	D_f^{thin}	$D_f^{extcorr}$	$D_{f-total}$
1	0.10	0.0476	0.10
2	0.10	0.0476	0.10
3	0.10	0.1568	0.156
4	0.15	0.0476	0.15
5	0.10	0.0476	0.10
6	0.12	0.0476	0.12
7	0.19	0.0853	0.19
8	0.11	0.0853	0.11
9	3.41	0.0476	3.41
10	0.15	0.0476	0.15
11	0.10	0.0476	0.10
12	0.10	0.0476	0.10

Table 9

Value of Probability of Failure (PoF)

Segmentation	Gff	D_f	F_{MS}	PoF
1	0.0000306	0.10	1	3.06×10^{-6}
2	0.0000306	0.10	1	3.06×10^{-6}
3	0.0000306	0.156	1	4.77×10^{-6}
4	0.0000306	0.15	1	4.59×10^{-6}
5	0.0000306	0.10	1	3.06×10^{-6}
6	0.0000306	0.12	1	3.67×10^{-6}
7	0.0000306	0.19	1	5.81×10^{-6}
8	0.0000306	0.11	1	3.37×10^{-6}
9	0.0000306	3.41	1	1.04×10^{-4}
10	0.0000306	0.15	1	4.59×10^{-6}
11	0.0000306	0.10	1	3.06×10^{-6}
12	0.0000306	0.10	1	3.06×10^{-6}

5. 2. 3. Estimated Consequence of Failure (CoF)

In the RBI methodology, the estimated CoF and PoF are based on the potential failure, including the human, tools, and environmental impact, which may cause financial losses for the company. Table 10 shows the business CoF of failed gas pipelines.

Table 10

Total Financial Consequences of Gas Pipeline Failure

Seg-menta-tion	FC_{cmd} (\$)	FC_{affa} (\$)	FC_{prod} (\$)	FC_{inj} (\$)	FC Total (\$)
1	110,458	82,462,858	22,419,936	973,630,415	105,628,767
2	110,458	0	639,945	0	640,056
3	110,458	0	639,945	0	640,056
4	110,458	0	639,945	0	640,056
5	110,458	0	639,945	0	640,056
6	110,458	0	639,945	0	640,056
7	110,458	0	639,945	0	640,056
8	110,458	0	639,945	0	640,056
9	110,458	0	639,945	0	640,056
10	110,458	0	639,945	0	640,056
11	110,458	0	639,945	0	640,056
12	110,458	3,908.395	3,908,423	243,407,603	7,694,966

Table 10 shows the financial CoF of the inspected pipelines. The first and last segments contribute to the possible business losses of nearly \$ 112 million.

5. 2. 3. Risk Matrix

According to Fig. 3, the PoF calculations for 12 segments of the subsea sales gas pipeline, only segmentation 9 has a higher damage factor value than the other segments due to a thickness reduction of 34 % from the initial thickness. Fig. 3 provides a clear risk matrix related to the uninspected sales gas pipelines.

From Fig. 3, it can be noted that most of the pipeline segmentation remains under a lower to medium risk level. The matrix is aligned with Table 11, which exemplifies how the risk level is calculated from D_f, PoF, and CoF values.

It can be concluded that segment 9 remains consistent with the previous results, which may increase the risk of pipeline defect. The CoF loss is USD 640,056, less than for segments 1 and 12 with the same risk level. According to Table 11, segments 1, 9, and 12 are categorized as a medium condition. This is already correct (Table 11).

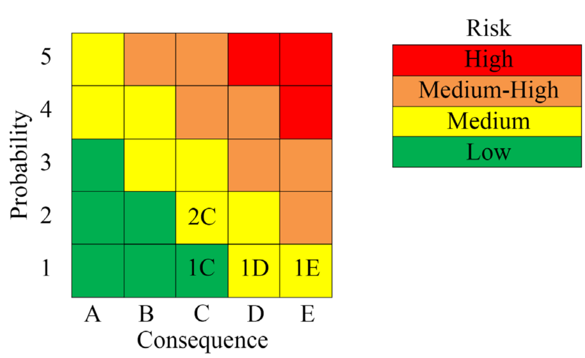

Fig. 3. The result of Risk Matrix of Sales Gas Pipelines

Table 11

Risk Level of the Gas Pipeline

Segmentation	D_f	PoF	CoF	Risk Level	Risk Category
1	0.10	3.06×10^{-6}	105,628,767	1E	Mediun
2	0.10	3.06×10^{-6}	640,056	1C	Low
3	0.15	4.77×10^{-6}	640,056	1C	Low
4	0.15	4.59×10^{-6}	640,056	1C	Low
5	0.10	3.06×10^{-6}	640,056	1C	Low
6	0.12	3.67×10^{-6}	640,056	1C	Low
7	0.19	5.81×10^{-6}	640,056	1C	Low
8	0.11	3.37×10^{-6}	640,056	1C	Low
9	3.41	1.04×10^{-4}	640,056	2C	Medium
10	0.15	4.59×10^{-6}	640,056	1C	Low
11	0.10	3.06×10^{-6}	640,056	1C	Low
12	0.10	3.06×10^{-6}	7,649,966	1D	Medium

5. 3. Interval Inspection Planning

In this work, the inspection period intends to reduce the risk level, which can be reflected by calculating the remaining useful life. According to the corrosion rate of 0.33 mmpy, the remaining thickness will reach the required minimum thickness after 20 years or in 2033. Fig. 4 shows the remaining life projection from the year of observation.

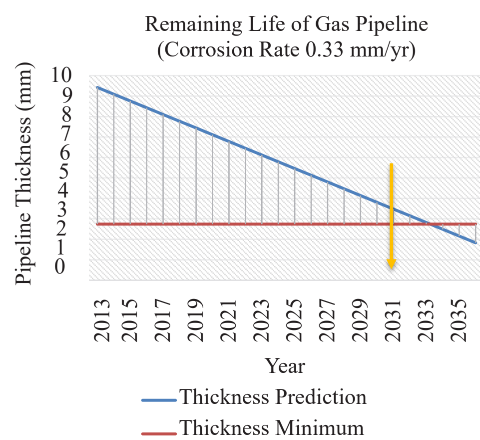

Fig. 4. Schematic of the Gas Pipeline Inspection Intervals

According to Fig. 4, the Inspection of the sales gas pipelines is in 2033, in which the minimum line meets the prediction thickness.

6. Discussion of the results of the unpiggable Risk-based Inspection study

Overall, the ILI data for each segment indicate that the internal corrosion rate is relatively low for a 28-year-old gas pipeline. The corrosion rate is extremely low due to the absence of water in the gas supply pipe [11].

As illustrated in Table 3, corrosion begins in segments 6 to 9, resulting in a loss of pipe wall thickness ranging from 11 % to 34 %. A bathymetric survey of the seabed profile revealed a significant increase and decreased over a short period. The point of sea depth drops steepest in segment 7 (30,000–35,000 m from the Datum), a seabed basin that rises continuously and irregularly. The results obtained are a result of ILI, which is now regarded as having a high level of accuracy. More remarkable than other pipeline inspection methods. In segment 8, the thickness loss due to internal corrosion was 20 % in 2007 but only 19 % in 2013. This data remains significant because ILI has a 90 % accuracy rate.

On the other hand, inconsistent seabed profiles result in the formation of natural bends in the pipeline, which can result in a turbulent flow.

This result is similar to the study given in [32, 33], which shows that the development of the intervention of operation is necessary to ensure the availability and flexibility of drilling rigs to acquire information related to the posture of the natural bed pipeline. It includes the design of material related to water depth rate, capacity of load deck, material barge, and hydralift. This study will help to hinder the effect of turbulence in pipelines.

To determine the location of the highest depletion in segment 9, additional analysis by simulating the fluid flow pattern in the pipe is required.

On the other hand, CO_2 corrosion occurs only when dissolved in water, forming the corrosive weak carbonic acid H_2CO_3 [34]. The greater the partial pressure of CO_2, the greater the rate of carbonic acid reduction, increasing carbonic acid concentration [35]. The temperature of the gas in this pipeline is higher than the temperature of seawater, and condensation will occur. According to operating data, the gas temperature is 32.22 °C while the seawater temperature in Northern Java is 22–31 °C [36]. Condensation occurs in the subsea sales gas pipeline due to the temperature difference between the gas and seawater. Consistent reports of pigging activity confirm the presence of condensation caused by gas cooling.

It affects by lowering the pH of the carbon steel's surface. Turbulence also results in the loss of the protective $FeCO_3$ layer, which is swept away by the flow [37]. The reaction is described in the reaction for forming a protective layer of $FeCO_3$.

Sampling the gas fluid in the distribution pipe also analyzes for the presence of H_2S, a compound that can result in the Stress Corrosion Cracking (SCC) mechanism of damage. Moreover, the analysis of fluid samples flowing through the sales gas distribution pipe revealed the presence of CO_2 and H_2S impurities in place of SRB (Sulfate Reduced Bacteria).

Based on the result of risk-based Inspection, the Probability of Failure (PoF) is calculated by multiplying the Generic Failure Frequency (GFF), the Management System Factor (FMS), and the Damage Factor (D_f). The final value of PoF is determined by considering the screening characteristics of each damage mechanism. The screening criteria include inspection results, damage mechanisms, records of previously occurring damage, and fluid sampling data to determine the level of impurities in the gas that affect the corrosion rate, such as CO_2, H_2S, and SRB. According to the gas phase properties, the high molecular weight of 23 kg/kg-mol, with constant pressure specific heat capacity of 44.70 J/kg K, will allow the phase inside the containment, in this case, the distribution pipe, and it is gas when it exits under ambient conditions.

On the other hand, the CoF includes several factors, including component damage, equipment damage, fire-affected area, financial interruption of business, and personal injuries. The mentioned factors are associated with the segment with unique location value and the time needed to repair as agreed with the publication [38]. According to the API-581 standard, the CoF value includes geographic or pecuniary values. Area-based calculations are made to determine the influence of a particular area on equipment damage and crew injuries in the case of a fire. Each length of the subsea gas pipeline has the same CoF value of 1873 m^2 for personnel injuries due to this computation. The CoF calculation based on area ignores the location of the distribution pipe segment, regardless of whether it is placed at sea or on land; it also disregards the conditions around the failure location, such as the presence of numerous industrial equipment and employees. Because the pipeline used to sell subsea gas is subject to various environmental conditions, area-based assessment is deemed unacceptable. The pipeline segment in the mid-ocean area should have a lower CoF value than the pipeline segment on land, surrounded by numerous production facilities and employees [39]. As a result, a complete review based on financial data is required.

CoF is calculated on a financial basis by identifying the conditions surrounding the distribution pipe in the event of a failure, such as the number of pieces of equipment that will be damaged in the event of a failure, production loss that will require repairs, and the population density around the failure location [40]. The results of the financial computation of the CoF are shown in Table 10. Financial calculations are performed by multiplying the area of the affected region, which is determined by the CoF calculation, by the area determined by the cost required to repair the area surrounding the failure, plus any losses incurred due to the halt of production for repairs. Additionally, the loss due to personnel injury resulting from a fire is computed by multiplying the affected area by the surrounding population density.

Segment 1 is at level E and exhibits a loss value of $105,628,767 due to its proximity to the offshore platform and the possibility of a failure affecting the platform [41]. Thus, segment 1 has a greater financial loss value than segment 2, up to segment 11, which is submerged in water and has a financial loss of $640,056, and segment 12, which is on land and has a financial loss of $7,649,966. Segments 2 to 11, which are submerged, have a value of 0 for losses due to replacing damaged nearby equipment (FC_{affa}), as there are no affected buildings. Similarly, the cost of replacing personnel injured due to a fire is zero because no personnel is present near the gas distribution pipe. Only the cost of repairing the damaged pipeline segment (FC_{cmd}) and the cost of lost production (FC_{prod}) due to fire are considered in the calculations for segments 2 to 11. Because segment 12's asset value is lower and its employee count is lower than in segment 1, segment 12 is classified as a CoF D segment.

The calculation in segment one is based on the assumption of pipe failure beneath the offshore platform, resulting in a collection of gas directly beneath the platform and a fire on the platform's side. API-581 does not take the location of the failure into account when calculating the fire impact area; naturally, the potential for fire in the subsea portion will be less than the potential for fire in the portion above the water.

The risk matrix in Table 10 shows that a single leak history influenced the damage factor in 2010 and their corresponding PoF of 0.61506 failures annually. As such, the inspection interval can be conducted to remove the insignificant risk level. According to (8), the predicted remaining life is 20.23 years. It is possible to conduct another inspection in 2023. Despite various standards used to measure the inspection interval, it is noteworthy to elicit that the work method is suitable to measure the risk.

The weakness of this study can be formulated by the risk measurement of gas sales only in which the same procedure can be implemented to the main oil line system. In addition, the method is ideally sufficient to predict the forthcoming inspection plan with or without a mitigation plan being executed in the field.

In this case, the sales gas, which has never been inspected due to the high corrosion resistance, may perform differently to lower the risk while reducing costs. In detail, the operating equipment remains at its safe level, which creates a lower negative effect on the condition of the pipelines that require a more frequent inspection time.

This shortcoming can be addressed by utilizing various suitable methods to show that implementing the root-cause failure analysis (RCFA) will help to overcome the existing inspection method. Therefore, the technique must be implemented to investigate the main oil gas lines. According to the literature [42], the method of Winkler-type beam on-spring is suitable to overcome the difficulty in measuring the risk under different conditions.

The inline Inspection also deals with numerous data, which may be vulnerable to human subjectivity in measuring the risk. With the data complexity, noise, and uncertainty, engaging the study by utilizing Artificial Intelligence to free the analysis from human subjectivity is noteworthy. Supervised and unsupervised machine learning has been developed recently as a primary tool to address the challenge of data complexity [43]. In this case, the inspection data is split into training and testing data, where the evaluation of the training data is possible.

7. Conclusions

1. The highest PoF value is found in segment nine at 1.04×10^{-4} failures per year, classified as PoF category two, with a corrosion rate of 0.33 mmpy. The remaining eleven segments are classified as 1 PoF.

2. According to the risk based on the risk-based inspection method, the medium risk category is divided into three segments: segment 1 (risk level 1E), segment 2 (risk level 2E), and segment 3 (risk level 3E). Segment 1 has a PoF of 3.06×10^{-6} failures per year and a CoF of USD 105,628,767; Segment 9 has risk level 2C, with 1.04×10^{-4} failures per year and a CoF of USD 640,056; Segment 12 has risk level 1D, with 3.06×10^{-6} failures per year and a CoF of USD 7,694,966. Low risk comprises nine segments with a risk rating of 1C, namely segments 2 to 8 and segments 10 and 11. The result indicates qualitative or quantitative indicators of the research results.

3. The successive inspection schedule based on the RBI estimates that the next Inspection will occur 20 years from the last, in 2033. This inspection interval was calculated to be longer than the previous one, only six years (2007–2013). The result is associated with quantitative results.

Conflict of interest

The authors declare that they have no conflict of interest with this research, whether financial, personal, authorship, or otherwise, that could affect the research and its results presented in this paper.

Financing

The authors thank the Indonesian Directorate General of Higher Education, Ministry of Education, Culture, Research, and Technology, for funding the research under the International publication of (PUTI) Q2 and Matching Fund 2022–2023 with contract number: NKB-1477/UN2.RST/HKP.05.00/2022.

Data availability

Data cannot be made available for reasons disclosed in the data availability statement.

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