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Fitness for service and risk-based inspection for line piping leakage of hydrocarbon release at offshore northwest java topside facility

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Abstract

Hydrocarbon leaks from offshore facilities can pose serious risks to workers, the environment, equipment, and operations. This study evaluated the safety and reliability of a repeatedly leaking three-phase piping system and assessed whether it could continue operating safely over the next 20 years. Fitness-for-Service (FFS) assessment based on API 579-1/ASME FFS-1 and Risk-Based Inspection (RBI) following API 581 were applied to evaluate the piping condition, risk level, remaining service life, and inspection requirements. Field observations and investigations were performed to evaluate piping conditions, while RBI and Estimated Life (EL) calculations were used to assess risk, remaining service life, and future piping conditions. Level 1 and Level 2 FFS assessments indicated that neither piping system could be considered fit for operation over the next 20 years, requiring a more detailed Level 3 assessment. Initially, both piping systems were classified in the yellow risk zone, but the risk was predicted to increase to the orange zone after 72 months. Therefore, The piping systems require further integrity assessment and risk mitigation to support safe long-term operation. Timely inspection, maintenance, repair, or replacement should be implemented to control increasing risk and ensure safe and reliable offshore operations.

Keywords: Fitness for service (FFS), Piping leakage, Risk-based inspection, Three-phase service.

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1. Introduction

Preventing and mitigating hydrocarbon emissions is important because they can lead to serious accidents in the oil and gas industry. Therefore, pipelines and other pressurized equipment must remain in good condition to ensure safe and reliable operation. However, these components can gradually deteriorate or fail due to exposure to corrosive substances, such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S), that are present in the system. For this reason, pipelines in the petrochemical industry are regularly inspected for damage, including blistering [1] and corrosion [2]. Predicting the pressure at which a damaged pipeline may fail is also important for assessing its safety. As pipelines become older, regular inspections and evaluations are needed to maintain their reliability and safe operation. In this context, Fitness-for-Service (FFS) provides a useful approach for evaluating whether damaged pipelines can continue to operate safely under actual service conditions.

Fitness-for-Service (FFS) assessments provide systematic engineering procedures that employ quantitative analyses to evaluate and verify the continued structural integrity of in-service equipment. According to API 579-1/ASME FFS-1, these assessments are conducted when components contain defects or damage, or when they operate under conditions that may increase the risk of failure [3]. For damaged components that remain in service, FFS assessments can be used to estimate their remaining service life under the original or modified operating conditions. FFS methods assess various types of damage, including general and localized corrosion, local thin areas [4] pitting [5, 6] (both widespread and localized), hydrogen-induced damage, shell distortions, weld misalignment [7] and crack-like defects [4, 8]. These defects may include environmental cracking, dents, gouges, and laminations.

In a refinery case study, Bakhtiari and his co-workers Bakhtiari, et al. [9] investigated a fire-damaged pressure vessel using an FFS assessment. The study incorporated hardness testing and microstructural characterization at multiple locations on the internal and external surfaces of the vessel to evaluate its overall structural integrity and serviceability. Simillarly, Tantichattanont, et al. [10] conducted an FFS assessment of a spherical pressure vessel that had experianced localized hot spot damage. Such localized overheating can occur in aging vessels due to factors including refractory degradation, flame impingement, and non-uniform flow of catalysts and reactive materials. These studies demonstrate the effectiveness of FFS in determining the continued serviceability of damaged equipment. However, structural integrity assessment alone may not capture failure probability and consequences, highlighting the need to complement FFS with risk-based approaches for more comprehensive safety and maintenance decisions.

Risk assessment plays a crucial role in safety management, and numerous studies have investigated risks associated with pipelines, offshore platforms, and process equipment, which represent major operational hazards in the oil and gas industry. Various methodologies have been applied, including qualitative and quantitative assessments, dynamic risk modeling, and analytical tools such as fault tree analysis, bow-tie diagrams, and fishbone charts. In particular, risk-informed assessment methods have been developed to support decision-making for offshore component replacement by evaluating time-dependent failure mechanisms and their consequences [11]. Bayesian updating combined with risk-based analysis has also been introduced to improve probabilistic modeling of pipeline deterioration [12]. Similarly, integrated risk-based assessment frameworks have been employed to predict the occurrence and consequences of failures in offshore crude oil pipelines [13].

Researchers have developed dynamic risk assessment frameworks that combine real-time data with risk levels to predict storage tank leaks. These approaches integrate qualitative analysis using fishbone diagrams with quantitative methods, including fault tree analysis (FTA) and Boolean algebra [14]. Both Risk-Based Inspection (RBI) and FTA have been applied to pipelines to reduce failure probability [15]. Similarly, in direct coal liquefaction, RBI also been used to assess leakage risk [16] and to determine appropriate inspection intervals for crude oil storage tanks [17].

In the oil and gas industry, quantitative risk assessments was performed on pipelines laid in a common trench [18]. The analysis combined fuzzy set theory with FTA to estimate the failure probability of individual pipeline, while a bow-tie diagram was employed to support risk management and control. Fuzzy logic approaches have also been applied to pipeline risk assessment, as demonstrated by Singh and Markeset [19]. Similarly, risk-based methods have been integrated with the Analytical Hierarchy Process (AHP) to identify effective maintenance strategies for oil refineries [20, 21]. In addition, an integrated quantitative risk analysis approach was applied to natural gas pipelines to improve the safety performance of the natural gas supply system.

Integrating risk management and data management within the RBI framework can support the development of efficient and effective strategies for piping system operation. In RBI methodology, risk is assessed based on the probability of failure (PoF) and consequence of failure (CoF) (API RP 581) [22]. As damage accumulates in pressurized component during service, the associated risk level may increase. When the estimated risk exceeds the established acceptance threshold, inspection is required to accurately determine the extent and severity of the damage.

In this study, an FFS assessment was performed in accordance with API 579/ASME FFS-1 guidelines using Level 1 and 2 evaluations [3]. The assessment was applied to a three-phase piping system in a topside offshore facility that had experienced repeated hydrocarbon leakage over a specified period. The piping system exhibited uniform and localized wall-thickness loss attributed to CO_2 corrosion, erosion, and flow-induced corrosion. Moreover, a quantitative RBI analysis based on API 581 standards was conducted to evaluate the associated risk, estimated the remaining service life, and recommend inspection strategies to reduce risk and prevent recurrent leakages in the piping system.

2. Methodology

2.1. Corrosion Rate (CR) Calculation

Two kinds of corrosion rate (CR) calculations were used in this study. The long term (LT) CR of piping was calculated using Equation 1 and 2, in accordance with API 570 [23].

$$Corrosion\ rate\ (LT) = \frac{t_{initial} - t_{actual}}{years\ in\ service} \quad (1)$$

Short term (ST) CR of piping was calculated using the following formula:

$$Corrosion\ rate\ (ST) = \frac{t_{previous} - t_{actual}}{years\ in\ service} \quad (2)$$

where t_{actual} denotes the inspected thickness at the time of measurement, $t_{initial}$ represents the width calculated at the same location as t_{actual} during the initial installation, and $t_{previous}$ denotes the wall thickness measured during one or more previous inspection.

2.2. Future corrosion allowance (FCA)

The future corrosion allowance (FCA) was determined based on previous inspection records or CR values reported for the component material under similar operating conditions. The FCA was calculated by applying the estimated CR over the intended service period, as expressed by the following formula:

$$FCA = corrosion\ rate\ (mmpy) x\ interval\ (years) \quad (3)$$

The assessment was conducted using a 20-year end-of-life target. FCA calculations were performed for both internal and external corrosion over the subsequent 20-year service period. The corresponding FCA values for internal and external corrosion were calculated using Equation 4 and 5 respectively [24]:

$$FCA_i = CR_i\ x\ (2043 - last\ inspection\ date) \quad (4)$$

$$FCA_e = CR_e\ x\ (2043 - last\ inspection\ date) \quad (5)$$

where FCA_i denotes the internal FCA (mm), FCA_e denotes the external FCA (mm), CRi denotes the internal CR (mm/year), and CR_e denotes the external CR (mm/year).

2.3. Fitness-for-Service (FFS) Assessment

Fitness-for-Service (FFS) assessment provides a systematic approach for evaluating the effects of in-service degradation and determining whether equipment can safely remain in operation, thereby avoiding premature replacement or unplanned shutdowns. Equipment deemed acceptable for continued service may remain operational subject to appropriate inspection and monitoring; otherwise, further evaluation, repair, or replacement may be required. FFS assessments are generally conducted at three levels, with Level 1 based on conservative assumptions and Level 3 providing the most detailed and accurate evaluation.

General metal loss refers to material loss caused by corrosion or erosion, as addressed in Part 4 of API 579-1/ASME FFS-1. This assessment is applicable when wall-thickness reduction occurs over a relatively broad area rather than at isolated locations. Point Thickness Readings (PTRs) can be used to evaluate such degradation when no significant variation exists among thickness measurements obtained at different inspection locations.

Three parameters were evaluated in the Level 1 FFS assessment. The first inlvolved calculating the average wall thickness from PTR. The acceptance criteria for this assessment was determined using the following formula:

$$t_{am} - FCA \geq t^C_{min} \quad (6)$$

where t^c_{min} denotes the minimum required thickness of the piping system based on its intended operating pressure, t_{am} represents the minimum measured thickness obtained from the latest inspection data. Metal loss on both the internal and external surfaces of the components was considered when determining the FCA.

Moreover, the wall thickness (t^c) used in the assessment was obtained through the following formula:

$$t^c = \frac{PD}{2(SEW + PY)} + CA \quad (7)$$

The second assessment involved calculating the Maximum Allowable Working Pressure (MAWP) based on the PTR data. The acceptance criteria for this assessment was determined using the following formula:

$$MAWP^C_r \geq MAWP \quad (8)$$

where $MAWP^c_r$ was calculated based on $t_{am} – FCA$ for thickness.

The third assessment involved determining the minimum measured wall thickness. The acceptance criteria for this assessment was determined using the following equation:

$$(t_{mm} - FA) \geq max[0.5t_{min}, t_{lim}] \quad (9)$$

where t_{lim} is the limiting thickness, and the value referred to the information provided which applied to the piping system.

$$t_{lim} = max\ [0.2t_{nom}, 1.3mm\ (0.05\ inch)] \tag{10}$$

t_{nom} represents the specified or intended thickness of the pipe wall as determined by the design or engineering standards.

When the Level 1 assessment criteria were not satisfied, a Level 2 assessment was performed. According to API 579-1/ASME FFS-1, the assessment parameters at Level 2 are similar to those used in Level 1, but the calculation incorporates the allowable Remaining Strength Factor (RSF_a). For major design codes, the recommended RSFa value is 0.9.

The Level 2 assessment also involved three parameters, consistent with those evaluated in Level 1. The first involved calculating the average measured thickness from the PTR data, with acceptance criteria similar to those applied in Level 1. However, the minimum required thickness (t^c_{min}) was determined using the design pressure multiplied by the RSF_a value. The second parameter involved calculating the MAWP from the PTR data, with the corresponding acceptance criteria given by Equation 11.

$$\frac{MAWP_r^C}{RSF_a} \geq MAWP \tag{11}$$

The third assessment involved determining the minimum measured wall thickness, with acceptance criteria identical to those applied in the Level 1.

2.4. Risk Analysis

Risk can be described as the potential for harm, loss, or adverse consequences due to the progression of an event [14]. Mathematically, risk is determined by combining the probability of occurrence within specific time period with its associated consequences, as expressed in Equation 12.

$$Risk\ \left\{\frac{Consequence}{Time}\right\} = Probability \left\{\frac{Event}{Time}\right\} x\ Impact \left\{\frac{Consequence}{Event}\right\} \tag{12}$$

Risk analysis was conducted to support risk management and control, with a focus on hazard identification, reliability improvement, and accident prevention. The main stages involved identifying hazards and threats, analyzing their causes and consequences, considering exposure and risk acceptance criteria, and evaluating the resulting risks. Risk analysis approaches have evolved from traditional methods toward more dynamic frameworks [25].

Potential risks were evaluated and ranked using a 5×5 risk matrix developed from historical statistical data [26]. The matrix combines the probability of occurrence on one axis with the associated consequences on the other, with the highest risks located in the upper-right region, as shown in Table 1. Risk were categorized as high (orange-red), medium (yellow/ALARP), and low (green). Risk levels were assessed using qualitative, quantitative, and semi-quantitative approaches.

Table 1.
5×5 Risk Matrix.

Probability / **Consequence**	**Almost Impossible (0% < X≤20%)**	**Very Low (Unlikely) (20% < X≤40%)**	**Low (Possible) (40% < X≤60%)**	**Medium (Likely) (60% < X≤80%)**	**High (Almost Certain) (80% < X<100%)**
Catastrophic	5x1	5x2	5x3	5x4	5x5
Major	4x1	4x2	4x3	4x4	4x5
Moderate	3x1	3x2	3x3	3x4	3x5
Minor	2x1	2x2	2x3	2x4	2x5
Slight	1x1	1x2	1x3	1x4	1x5

Following the API RP 581 (2016) guidelines, a quantitative RBI software tool was developed to evaluate risk, estimate remaining service life, and recommend inspection or mitigation strategies for piping systems experiencing recurrent leakage. Although the software was initially developed in accordance with API RP 581 (2016), modifications were made to the damage factor calculations, consequence assessment, and inspection and mitigation procedures.

The overall risk level was determined from the probability of failure (PoF) and consequence of failure (CoF). Specifically, PoF was calculated as the product of the generic failure frequency (*gff*), damage factor ($D_f(t)$), and management system factor (FMS), as shown in Equation 13.

$$P_f = gff.F_{MS}.D_f(t) \tag{13}$$

Here, *gff* represents the generic failure frequency of the component prior to the occurrence of a specific damage mechanism or environmental exposure during operation. The damage factor ($D_f(t)$) was determined based on the specific damage mechanism affecting the component. In contrast, the management system factor (FMS) was applied uniformly across the facility and was assigned a value of 1 in this study.

Four main consequences categories were considered in the calculation of the consequence of failure (CoF), as area CoF categories namely flammable and explosive consequence CA_{cmd}^{flam} and CA_{inj}^{flam}, toxic consequence CA_{inj}^{tox}, non-toxic & non-flammable releases CA_{inj}^{nfnt}, and final consequence area, respectively refer to Equation 14.

$$CA = max\ [CA_{cmd}, CA_{inj}] \tag{14}$$

The financial consequences of equipment failure in process plants were divided into several CoF categories. These included the cost of repairing or replacing the failed component (FC_{cmd}) and the cost of collateral damage to surrounding equipment within an affected area FC_{affa}.

Beyond direct equipment damage, associated costs included downtime losses (FC_{prod}), potential injury-related expenses (FC_{inj}), and environmental clean-up requirements ($FC_{environ}$), as expressed in Equation 15.

$$FC = FC_{cmd} + FC_{affa} + FC_{prod} + FC_{inj} + FC_{environ} \tag{15}$$

The economic impacts associated with environmental consequences included compensation for affected fisheries and tourism businesses, ecosystem restoration costs, and oil spill recovery expenses. Compensation for fisheries and tourism businesses covered revenue losses incurred during both the incident and subsequent cleanup activities [27, 28].

The PoF and CoF ranges used to define the risk matrix categories are summarized in Table 2. The PoF was quantified as the failure frequency over a specified period, whereas the CoF was expressed in terms of affected area or financial impact.

Table 2.
Associated Values for Probability of Failure and CoF, Classified by Area and Financial Criteria.

PoF Category		**Severity & Consequence Category**		
Category	**Probability Range**	**Category**	**Impacted Area (m²)**	**Financial Range ($)**
1	PoF ≤ 3.06E -05	A	CA ≤ 9.29	FC ≤ 1,000
2	3.06E -05 < PoF ≤ 3.06E -04	B	9.29 < CA ≤ 92.9	1,000 < FC ≤ 10,000
3	3.06E -04 < PoF ≤ 3.06E -03	C	92.9 < CA ≤ 929	10,000 < FC ≤ 100,000
4	3.06E -03 < PoF ≤ 3.06E -02	D	929 < CA ≤ 9290	100,000< FC ≤ 1,000,000
5	PoF > 3.06E -02	E	CA > 9290	FC > 1,000,000

2.5. Estimate Life

The estimated life (EL) was calculated as the difference between the most recent thickness measurement (t_{rd}) and the required minimum thickness (t_{req}), divided by the corrosion rate (CR), as expressed in Equation 16.

$$EL = \frac{t_{rd} - t_{req}}{CR} \tag{16}$$

The calculation for t_{req} was determined as shown in Equation 17:

$$t_{req} = \frac{P\ R}{(SE + 0.4P)} \tag{17}$$

Here, P was taken as 130% of the maximum operational pressure, R denoted the external radius, S corresponded to the higher limit of allowable stress, and E referred to the joint efficiency.

2.6. RBI

A key step in developing the inspection plan was establishing the target inspection date. As the probability of failure increases with progressive degradation, the RBI software used a linear iterative approach to determine the inspection date based on the maximum allowable PoF as the risk criterion. The selected PoF threshold was subsequently adjusted according to the applicable company policies, as illustrated in Figure 1.

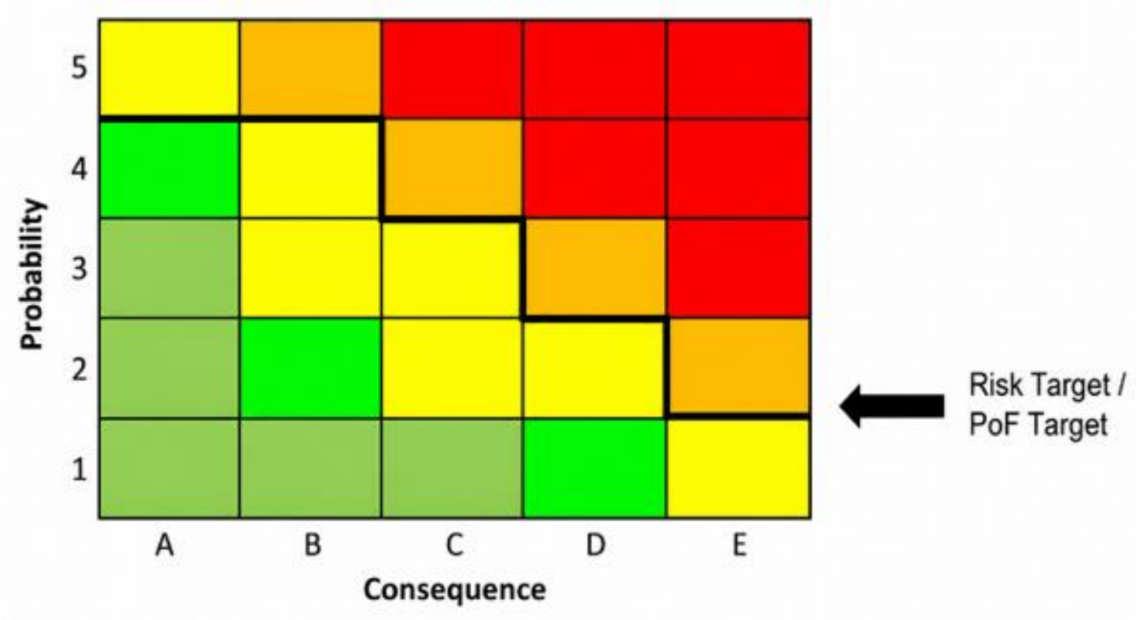

Figure 1.
Representation of Risk Target and Probability of Failure (PoF) Threshold within the Risk Matrix.

Equipment inspection was recommended when the risk level approached or reached the predefined target. The inspection recommendation was based on the damage mechanism associated with the highest damage factor. Accordingly, the inspection schedule was established to ensure that inspections were conducted when the calculated risk reached the defined target.

2.7. Case Study

In this study, three carbon steel piping lines, designated as Lines 1, 2, and 3, were investigated. The lines conveyed water, oil, and gas phases and were located on the topside of an offshore platform in Northwest Java. The piping system had experienced recurrent leakage over the previous three years.

3. Results and Discussion

During the investigation, the long-term (LT) internal corrosion rate (CR) was used because of the limited availability of inspection data. The external CR used for the damage factor calculation was obtained from Table 16.3/16.3M of API RP 581 and determined based on the operating temperature of the process piping. The internal and external CR values were subsequently used to calculate the future corrosion allowance (FCA), as summarized in Table 3.

Table 3.
CR and FCA calculation.

Line No.	CR (mm/year)		FCA (mm)	
	Internal	External	Internal	External
Line 1	0.114	0.127	0.11	0.13
Line 2	0.188	0.127	2.82	1.91
Line 3	1.166	0.051	22.15	0.97

Point Thickness Readings (PTRs) were used to characterize metal loss when no significant variation was observed among the measured thickness values. For all piping systems, the measurements were obtained from straight-pipe sections, and the lowest recorded thickness from the latest inspection was used for the assessment. Due to the limited inspection data available, the minimum measured thickness, t_{mm}, was considered equivalent to the average measured thickness, t_{am}. The results of the first assessment, which involved calculating the average measured thickness from the PTR data, are presented in Table 4. The results of the second assessment, which involved determining the Maximum Allowable Working Pressure (MAWP) from the PTR data, are presented in Table 5.

Table 4.
Result of 1st Assessment Parameter Level 1 General Metal Loss Assessment.

Line No.	Average measured thickness, t_{am} (mm)	FCA (mm)	t_{am} – FCA (mm)	t_{min} (mm)	Criteria Result (t_{am} – FCA) $\geq t_{min}$
Line 1	8.58	6.03	2.55	5.66	Not passed
Line 2	7.24	8.19	-0.95	1.54	Not passed
Line 3	6.26	26.77	-20.51	3.05	Not passed

Table 5.
Result of 2nd Assessment Parameter Level 1 General Metal Loss Assessment.

Line No.	$MAWP_r^c$	MAWP	Criteria Result ($MAWP_r^c \geq MAWP$)
Line 1	42.28	93.08	Not Passed
Line 2	-11.92	17.93	Not Passed
Line 3	-537.1	93.08	Not Passed

The calculation results for the third assessment, which included determining the minimum measured thickness, are presented in Table 6. Based on the three assessment parameters presented in Tables 4–6 none of the piping systems satisfied the Level 1 FFS acceptance criteria. Therefore, a Level 2 assessment was conducted. The acceptance criteria for the three Level 2 assessment parameters were consistent with those applied in Level 1. However, the minimum required thickness was recalculated by incorporating the allowable Remaining Strength Factor (RSF_a). The Level 2 assessment results, using an RSF_a value of 0.9, are presented in Table 7.

Table 6.
Result of 3rd Assessment Parameter Level 1 General Metal Loss Assessment.

Line No.	Minimum measured thickness, t_{mm} (mm)	FCA (mm)	$0.5t_{min}$ (mm)	t_{lim} (mm)	Criteria Result (t_{mm} – FCA) > max ($0.5t_{min}$, t_{lim})
Line 1	8.58	6.03	2.83	2.19	Not passed
Line 2	7.24	8.19	0.77	1.64	Not passed
Line 3	6.26	26.77	1.52	1.52	Not passed

The Level 2 FFS evaluation results, presented in Table 7, indicated that none of the piping systems satisfied the assessment criteria. Therefore, recalculation of the Maximum Allowable Working Pressure (MAWP) or design pressure was necessary to determine whether the system could safely operate at a lower pressure over the subsequent 20-year service period. If damage persisted or safe operation could not be ensured, repair or replacement would be required. Subsequently, a Level 3 assessment may be conducted, which requires more detailed inspection data and component-specific information. In addition, supplementary analyses may be performed using numerical techniques, particularly finite element modelling, or experimental approaches, depending on the nature of the damage. These approaches are consistent with the FFS assessment of fire-damaged equipment in a refinery unit reported by Bakhtiari and colleagues [9]. The assessment required destructive tensile testing to obtain accurate data on the final tensile strength and determine the allowable operating pressure, as demonstrated in the Level 3 FFS assessment of fire-damaged equipment. Similarly, a Level 3 assessment in the present study would require stress analysis using the finite element method to determine the stress distribution within the component.

Using the collected data, a quantitative Risk-Based Inspection (RBI) analysis was conducted using the developed software. Risk assessments were performed over three 24-month inspection periods (IP1, IP2, and IP3), with the results presented in a 5 × 5 risk matrix based on the probability of failure (PoF) and consequence of failure (CoF), as shown in Table 8. Quantitative analysis was not performed for Line 2 because it was classified as a riser. In addition to risk assessment, the software estimated the remaining service life and target dates and determined appropriate follow-up inspection or mitigation measures for the investigated piping systems.

Table 7.
Result of Level 2 General Metal Loss Assessment.

Line No.	t_{min} (mm)	Criteria Result (t_{am} – FCA) $\geq t_{min}$	Criteria Result ($MAWP_r^c/RSF_a \geq$ MAWP)	Criteria Result (t_{mm} – FCA) > max ($0.5t_{min}$, t_{lim})
Line 1	5.12	Not passed	Not passed	Not passed
Line 2	1.52	Not passed	Not passed	Not passed
Line 3	2.76	Not passed	Not passed	Not passed

Table 8.
Summary and Comparison of RBI Results Highlighting Risk Levels and Estimated Service Life.

Line No.	IP 1	IP 2	IP 3	EL (year)
Line 1	1E	1E	2E	0
Line 2	2D	2D	3D	52.78

The risk level for Line 1 was within the yellow zone during IP1 and IP2 but increased to the orange zone during IP3. This increase in risk was attributed to the predicted progression of active damage mechanisms affecting the piping system. The estimated life (EL) of Line 1 was calculated as 0 years, indicating that the piping system did not have sufficient remaining service life under the evaluated conditions. Line 2 exhibited a similar risk trend, with the risk level remaining within the yellow zone during IP1 and IP2 and increasing to the orange zone during IP3. However, its position within the risk matrix differed from that of Line 1.

The recommended inspection or mitigation dates for each piping system are listed in Table 9. The planning criteria were based on the estimated life; mitigation was recommended when the remaining life was less than five years, whereas inspection was scheduled when the remaining life exceeded five years. The software initially determined a target date based on the calculated risk level. For mitigation cases, the final target date was limited to a maximum of 72 months when the calculated inspection interval exceeded this period. If the risk level during IP1 already exceeded the predefined target, the initial target date was set to zero.

Table 9.
Summary of RBI Outcomes for Planned Inspection/Mitigation Dates.

Line No.	Initial Target Date (Month)	Final Target Date (Month)	Planned Date for Inspection or Mitigation
Line 1	39	0	March 1, 2019
Line 2	34	34	July 21, 2024

Due to the EL of Line 1 was less than five years, the final target date was set to zero, indicating the need for immediate mitigation. A mitigation plan was therefore required to address the insufficient remaining service life. The recommended actions included repairing or replacing the affected piping system to restore its structural integrity and ensure safe operation.

The subsequent inspection or mitigation schedule was established based on the most recent inspection date or commissioning date. Since the RBI assessment was conducted using the latest available data from 2022, any overdue inspection or mitigation actions were prioritized for implementation.

In similar study conducted by Zhan and co-workers [16] 885 pipes and 124 vessels were evaluated using RBI method. The results showed that 60.2% of the pipes and 63.6% of the vessels were classified as medium risk, corresponding to the yellow zone of the risk matrix. To address the potential for leakage in piping and vessels, inspection schedules were recommended according to the risk category. Equipment classified as medium–high risk was assigned inspection intervals of 2–4 months, while medium- and low-risk equipment were assigned intervals of 4–6 and 6–8 months, respectively. In addition to inspection planning, fixed and portable sensors and detectors were installed in potential leakage areas to enhance the inherent safety of the process.

4. Conclusion

In conclusion, hydrocarbon emissions pose significant risks, including loss of life, environmental damage, reputational impacts, and economic losses. Therefore, a comprehensive risk assessment is essential to ensure the safe and reliable operation of piping systems throughout their intended service life. In this study, a quantitative Risk-Based Inspection (RBI) assessment was conducted to evaluate risk levels, estimate remaining service life, and establish inspection or mitigation schedules for each piping system, with the objective of reducing the likelihood of recurrent leakage.

The FFS assessment results showed that none of the investigated piping systems (Lines 1, 2, and 3) located on the topside of an offshore platform in Northwest Java satisfied the Level 1 or Level 2 acceptance criteria for the subsequent 20-year service period. Therefore, repair or replacement of the three-phase piping system was required to ensure safe continued operation under the specified conditions.

During the first inspection interval, the risk levels of the evaluated piping systems were within the yellow zone and increased to the orange zone during the third interval, corresponding to 72 months. Because the estimated life of Line 1 was less than five years, mitigation measures, including repair or replacement, were required. For Line 2, inspection should be conducted according to the proposed target date. Furthermore, a Level 3 FFS assessment is recommended for future studies to provide a more detailed evaluation when the Level 1 and Level 2 acceptance criteria are not satisfied.

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