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Applying Structural Reliability to Risk-Based Inspections of Underwater Crude Oil Pipelines

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Abstract: This study investigates the application of structural reliability methods in risk-based inspections (RBIs) for subsea crude oil pipelines. Given the increasing reliance on submarine pipeline infrastructure in offshore oil and gas operations, maintaining its integrity is critical to operational safety and environmental protection. This study uses inspection data from smart pigging operations carried out in 2020 and 2024 on 28.7 km of 12-inch underwater pipes. Using API RP 581 (2020) and First-Order Second-Moment (FOSM) structural reliability theory, this study quantitatively assesses the probability of failure (PoF) and the consequence of failure (CoF). Results showed active internal corrosion, with pitting corrosion identified as the dominant degradation mechanism. Risk projections from 2024 to 2030 reveal unacceptable levels of risk in 2030 if mitigation strategies are not implemented. Based on the financial impact and business risk thresholds, a tailored inspection and maintenance strategy is proposed. These findings support the optimization of inspection intervals and highlight the importance of corrosion control measures such as routine pigging and inhibitor injections.

Keywords: Risk-Based Inspection (RBI); Undersea Pipeline; Structural reliability; Internal corrosion; Probability of Failure (PoF); Consequences of Failure (CoF)

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1. Introduction

In the early 1970s, subsea field development began by placing wellheads and production equipment on the seabed. Over the past decades, subsea systems have advanced from manually operated shallow-water setups to remotely controlled installations at depths of up to 3000 m, supported by significant technological progress (Li et al., 2024).

The sustainability and stability of subsea pipelines is a top priority in the oil and gas industry, given their enormous contribution to the economy, the environment, and human life. serves as the primary infrastructure for draining resources from the offshore work area (Offshore Section) to the Receiving Facility (Onshore Section). Given the increasing global demand for oil and gas, ensuring that pipeline transportation capacity is adequate has become an important operational requirement. Therefore, maintaining the structural integrity and safety of pipelines is critical and requires comprehensive and thorough analysis to reduce the risk of failure. Pipeline failures can result in severe environmental consequences and substantial economic losses for operators. In this context, the probabilistic assessment of pipeline failure due to external corrosion has emerged as a key factor in understanding and managing pipeline integrity (Hocine et al., 2024; Seghier et al., 2018).

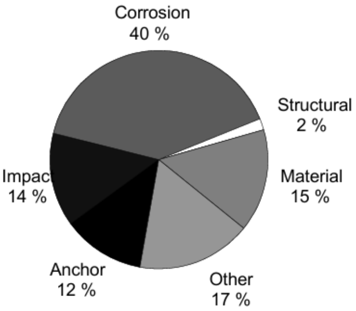


Figure 1. Failure in the Offshore Pipeline System (DNV RP F116)

The reliability and safety of these pipelines is crucial, as failures can lead to environmental damage and large operational losses. Therefore, risk assessment and management are an important part of the design, monitoring, and maintenance of subsea pipelines to prevent problems such as corrosion and damage due to external factors.

Based on the Regulation of the Minister of Energy and Mineral Resources No. 32 of 2021, every equipment and/or installation used in oil and gas business activities must undergo technical inspections and safety inspections. This aims to ensure that the equipment operates in excellent condition, works in safe conditions and minimizes accidents (Kementerian Energi dan Sumber Daya Mineral, 2021). In Indonesia, technical inspections can be carried out using two methods. namely time-based inspection and risk-based inspection (Nurbayanah et al., 2024). The time-based inspection method has the advantage of ease of implementation because it does not require complex technical analysis. However, this approach tends to require higher costs because the entire equipment is inspected at the same interval, without considering the level of risk. Alternatively, a Risk-Based Inspection (RBI) method can be applied that is more focused on risk priorities.

Risk-Based Inspection (RBI) is a systematic and risk-based approach used to design technical inspection programs for equipment in industrial process systems. This approach combines quantitative and/or qualitative evaluation of two main parameters, namely likelihood of failure and consequence of failure, to determine inspection priorities based on the actual level of risk posed by each piece of equipment (American Petroleum Institute, 2020). The RBI aims to allocate inspection resources efficiently, by giving higher priority to equipment with a high level of risk, as well as establishing tailored inspection methods, frequencies, and scopes (American Petroleum Institute, 2020).

Compared to the time-based inspection method, RBI is considered more effective because it takes into account the differences in operating conditions and vulnerabilities of each equipment. Time-based inspections tend to be uniform and do not take into account risk variations, so they can lead to over-inspection of low-risk equipment, and under-inspection of high-risk equipment. In addition, equipment degrades in quality that varies over time due to environmental factors, fluid type, and operating history, making it difficult for time-based approaches to accurately predict potential damage (Hameed et al., 2021).

The implementation of RBI not only provides cost efficiency and reduced downtime, but also improves operational safety, system reliability, and protection of the environment and personnel. Through a comprehensive risk analysis, mitigation and inspection strategies can be designed to maintain equipment performance according to its function (Hameed et al., 2021; Sözen et al., 2022).

Technically, the API RP 581 standard provides a quantitative methodology for calculating Probability of Failure (PoF) and Consequence of Failure (CoF). PoF is calculated through the Damage Factor (DF), formerly known as the Technical Module Sub-Factor (TMSF), while CoF is represented by the Leak Impact Factor (LIF). These factors accommodate the technical aspects of the equipment that affect the probability of failure as well as its impact on the environment, safety, and economy (American Petroleum Institute, 2020; Haryadi et al., 2020).

The implementation of RBI has been widely carried out in various industrial facilities in Indonesia. A study by Haryadi et al. (2020) on gas piping systems shows that the dominant failure is in the form of thinning, with a moderate risk value and an inspection interval is recommended every three years. Thus, RBI has proven to be a more adaptive, accurate, and efficient approach than conventional inspection methods, and is able to provide technical justification in strategic decision-making related to the inspection and maintenance of critical equipment (Haryadi et al., 2020).

In this study, technical data that includes design data and operational data is collected and analyzed for the subsea pipeline system. The study emphasizes the importance of risk analysis of underwater pipelines, given that their placement on the seafloor makes routine daily monitoring, such as those carried out on onshore pipelines, impossible. The standard used in this study is API RP 581 Third Edition, Addendum 2 of 2020, where the Probability of Failure (PoF) is determined based on the initial identification of the fault mechanism and using the FOSM theory of structural reliability, while the Consequence of Failure (CoF) is calculated based on the highest value of the impact of component damage and its consequences on personnel safety. In addition, the determination of risk limits is used as a reference in the classification of risk levels and inspection planning. This study aims to investigate the application of structural reliability methods in risk based inspection for subsea crude oil pipelines.

2. Experimental Materials and Methods

The researchers focused on the 12" main oil subsea pipeline at PT XYZ which is the design and operating condition based on **Table 1**. This study uses data from in-line inspection (ILI) reports using smart pigging technology. Risk assessment is carried out through a quantitative risk-based inspection methodology (RBI), in accordance with the API 581 standard (2020 edition), by analyzing and evaluating the corrosion rate obtained from the ILI data (American Petroleum Institute, 2020).

Table 1. Pipe Design and Operation

Parameters	Value	Unit
Pipe Identification	12" ABC	-
Total Length	28.7	Kilometer
Material	API-5L- X52	-
SMYS	52.000	Psi
SUTS	60.000	Psi
Design Code	ASME B31.4	-
Pipe Products	Crude oil	-
Nominal OD	12.75	Inch
CA	3.175	Mm
Wall Thickness	0.5	Inch
Design Factor	0.72	-
Design Temperature	200	F
Design Pressure	200	Psi
MAOP	250	Psi
Layer	Creation Layer	-

The subsea pipeline risk method will follow the process as shown in **Fig. 2** below. As seen in **Fig. 2**, risk is the multiplication between the chance of failure (POF) and the impact of failure (COF). This POF x COF product will generate a risk value for each segment of the pipeline regulated every 1 km of pipeline. For this QRA, the risk matrix used follows HSSE PT XYZ.

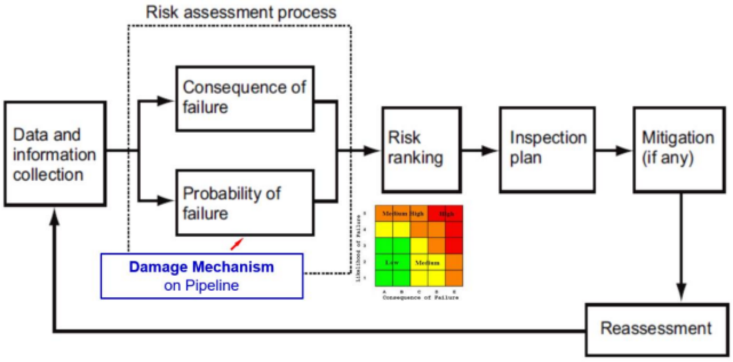


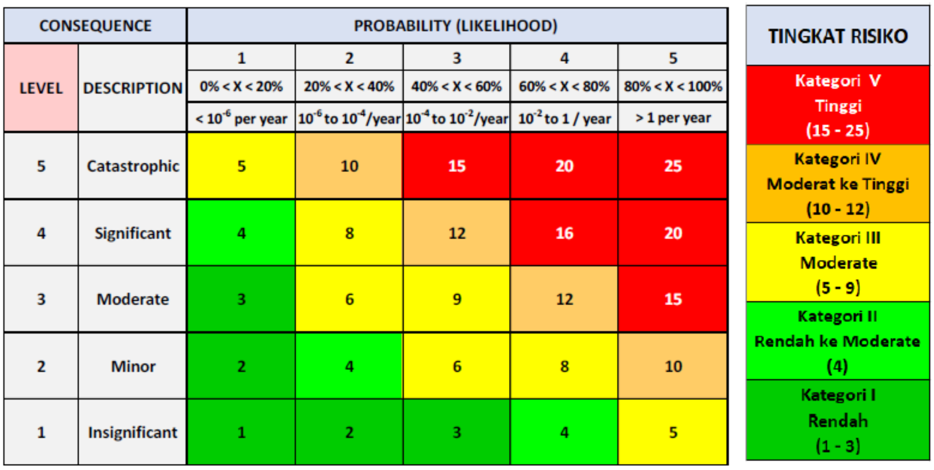
Figure 2. Risk assessment methodology

The risk assessment method, especially the determination of POF uses the FOSM theory of structural reliability, which is an approach from the integrity aspect as a counterpart method or approach from the side of process safety. Risk analysis in this approach is carried out in a quantitative manner, where risk is defined as the result of multiplication between probability and consequence, both of which are expressed in numerical form.

$$R(t) = \mathrm{Pof}(t) \times \mathrm{CoF} \tag{1}$$

The risk that occurs if the risk falls into category V (high-risk), then mitigation must be carried out immediately, if the risk is in category IV moderate to high, then mitigation must be carried out within 1-3 years depending on the remaining age of the pipeline. However, if the risk of falling is category III – I (moderate to low), then in general there is no specific effort that needs to be made, only a monitoring program or routine inspection (Purwidyasari et al., 2023).

Table. 2 Risk matrix untuk penentuan kategori risiko



CONSEQUENCE		PROBABILITY (LIKELIHOOD)				
LEVEL	DESCRIPTION	1	2	3	4	5
		0% < X < 20%	20% < X < 40%	40% < X < 60%	60% < X < 80%	80% < X < 100%
		< 10^{-6} per year	10^{-6} to 10^{-4}/year	10^{-4} to 10^{-2}/year	10^{-2} to 1 / year	> 1 per year
5	Catastrophic	5	10	15	20	25
4	Significant	4	8	12	16	20
3	Moderate	3	6	9	12	15
2	Minor	2	4	6	8	10
1	Insignificant	1	2	3	4	5

TINGKAT RISIKO
Kategori V Tinggi (15 - 25)
Kategori IV Moderat ke Tinggi (10 - 12)
Kategori III Moderate (5 - 9)
Kategori II Rendah ke Moderate (4)
Kategori I Rendah (1 - 3)

The implementation of the RBI's analysis requires the collection of data and information relevant to the analyzed subsea pipeline. The data is obtained from an alignment sheet that contains important information about the route and configuration of the subsea pipeline, process flow diagram, piping and instrumentation diagrams, material and construction data, and previous in-line inspection (ILI) reports. The composition of the flowing fluid, design data, operational data, as well as safety systems. All of this collected data will be used in the calculation of probability of failure (PoF), consequence of failure (CoF), and risk level evaluation, and will be the basis for scheduling inspection programs. The probability of failure is sometimes superseded by the rate of accidents, and the COF can be evaluated from the financial or safety losses of the person in terms of the number of deaths. The probability of failure (POF) which is the opposite of reliability (or the chance of operating without failure), as shown in the simple equation below (American Petroleum Institute, 2020; Purwidyasari et al., 2023).

$$\mathrm{Pof}(t) = \mathrm{GFF} \times \mathrm{DF}(t) \times \mathrm{FM} \tag{2}$$

$$\text{Reliability} = 100\% - \text{Probability of Failure, or } R(t) = 1 - \mathrm{POF}(t) \tag{3}$$

The impact of failure is usually taken into account from aspects; 1) safety, 2) environmental damage and 3) business loss due to oil and gas leakage resulting in financial losses. DNV-RP-F116 explains the division of the losses. For the determination of COF, the worst case scenario principles are usually taken (Norske Veritas, 2010).

During the design phase, the calculation of the design pressure or required thickness is based on a deterministic method, for example when calculating the required pipe thickness, a single sum of SMYS, pressure or otherwise is put into the equation. The risk aspect is only considered by including a few safety factors, such as class location, welding factor or temperature. However, in reality, those parameters are not single values, they always have distributions, and reliability theory takes those distributions into account and incorporates them into the calculations. The concept of structural reliability can be easily explained by the following diagram shown in **Fig. 3**. The probability of failure is described and measured by the area that overlaps between the loading factor and the material's resistance.

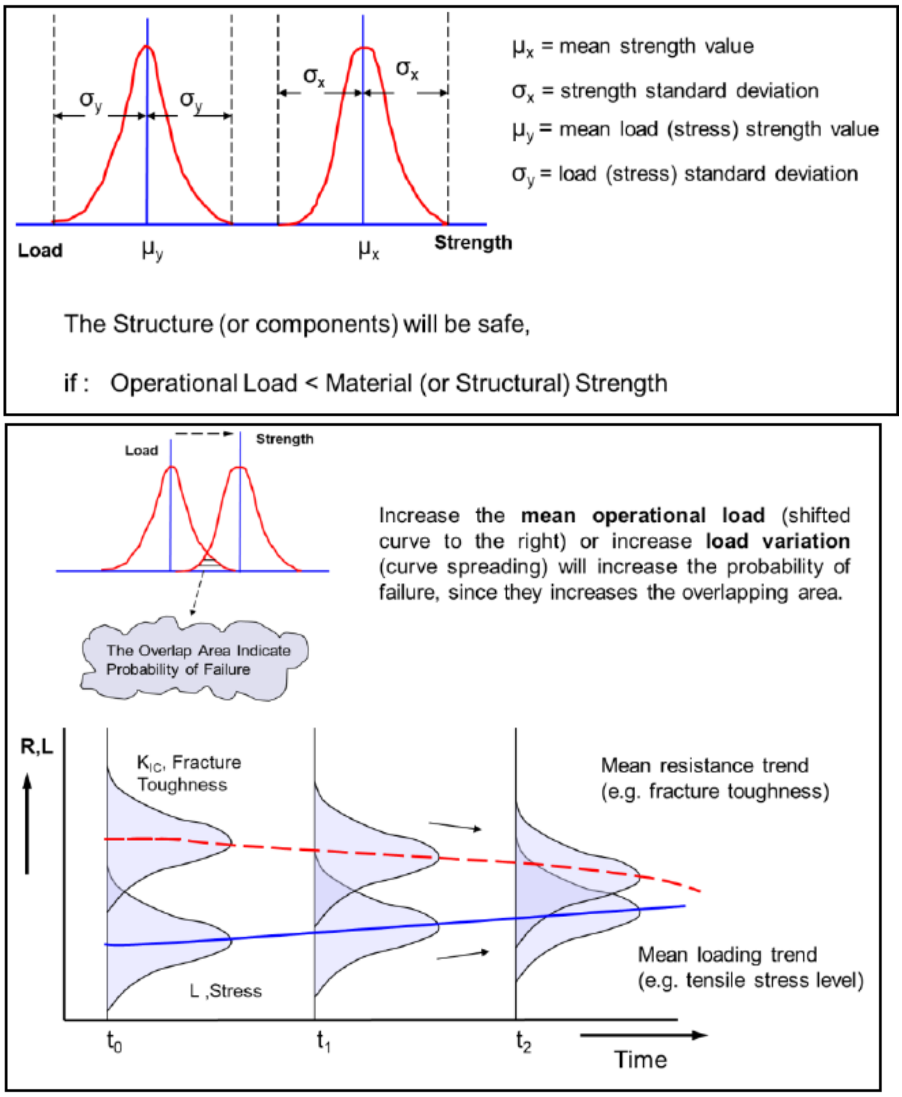


Figure 3. Concept of structural reliability

Probability is defined as the wedge between an increase in the load factor, in this case the tensile stress (and the spread of its curve) and a decrease in the resistance of the material, in this case the strength of the material yield (SMYS) or an increase in its spread (deviation). Without proper action, the likelihood of failure increases over time and the associated risks are increasing, as the area of the slice becomes larger.

To calculate the probability of failure, a linear equation was developed to describe the interference of load resistance or stress strength based on the concept of structural reliability. This is referred to as the finite state function, developed using the second-order moment theory of the first order [4]. The boundary state function is the function, g, which is the difference between resistance and load in the form of a linear equation (Det Norske Veritas, 2017).

$$g = \mathrm{R} - \mathrm{L} \tag{4}$$

g = limit state function

R = material resistance

L = demand, stress intensity factor

The pipe will fail if g ≤ 0 which means the operating load exceeds the resistance. When the voltage distribution and the power distribution follow the normal distribution function and are independent of each other, by utilizing the Taylor series.

Average Value

$$\mu g \approx \mu R - \mu L \tag{5}$$

Deviation

$$\sigma\mathrm{g} = \sqrt{\sigma_R^2 + \sigma_L^2} \tag{6}$$

$$\beta = \frac{\mu\mathrm{R} - \mu\mathrm{L}}{\sqrt{\sigma_\mathrm{R}^2 + \sigma_\mathrm{Y}^2}} \tag{7}$$

Reliability Index

$$\beta = \frac{\mu\mathrm{g}}{\sigma\mathrm{g}} \tag{8}$$

Probability of Failure

$$P_f = \Phi\,(-\beta) = 1 - \Phi(\beta) \tag{9}$$

Where:

Φ is the standard normal distribution function.

For the determination of the beta index, the standard table of normal distribution is commonly used.

Based on equation (4) if the thinning of the wall is due to corrosion, then the following boundary state function can be developed. The resistance of the material is represented by the yield force (Sy) and the load is replaced by the circular stress (Sh) and the equation of the boundary state function (4) becomes

$$g = Sy - Sh = 0.72\ Sy - \frac{\mathrm{PD}}{2\mathrm{t}} \tag{10}$$

Assuming that D is a constant, then:

Average value

$$\mu g = \mu Sy - \frac{\mu\mathrm{P\ D}}{2\mu\mathrm{t}} \tag{11}$$

Deviation

$$\sigma_g^2 = \left(\frac{dg}{dS_y}.\sigma_{Sy}\right)^2 + \left(\frac{dg}{\mathrm{dP}}.\sigma_P\right)^2 + \left(\frac{dg}{\mathrm{dt}}.\sigma_t\right)^2 \tag{12}$$

Reliability Index, β

$$\beta = \frac{\mu g}{\sigma g} \tag{13}$$

3. Results and Discussion

In 2020 and 2024, in-line inspections have been carried out on 12" subsea pipelines with smart pigs, the results of which are shown in **Table 2** below. The table shows statistical data on corrosion anomalies before and after the insertion (partial replacement) along 6 km in 2023. It is important to review the inspection results and fitness for service (FFS) results before conducting a risk assessment.

Table 2. Inspection Results and Anomalies Recorded Outside the Insertion Segment (Ref No.9).

Types of Anomalies	Feature (%) Wall Loss	ILI 2020 Number of Features			ILI 2024 Number of Features		
		KP0-KP0+323	KP 6 + 342-KP 28 + 702	Entire	KP0-KP0+323	KP 6 + 342-KP 28 + 702	Entire
Internal Corrosion	> 50%	2	138	140	-	-	-
	40 % - 49%	1	1.046	1.047	-	-	-
	30 % - 39%	12	6.762	6.774	1	2	3
	20 % - 29%	76	24.012	24.088	24	815	839
	10 % - 19%	2.220	109.294	111.514	4.333	155.862	160.195
	Total	2.311	141.252	143.563	4.358	156.679	161.037

Data from ILI in 2020 shows that there are 143,563 features due to internal corrosion that exceed 10% of the thickness of the pipe with 140 anomalies having a depth of more than 50% of the thickness of the pipe. Meanwhile, the results of the 2024 ILI inspection show a total of 161,037 features of internal corrosion that exceed 10% metal loss, with the highest value falling in the 30% - 39% metal loss category.

Table 3. Inspection Results and Anomalies Recorded in the Insertion Segment (Ref No.9).

Types of Anomalies	Feature (%) Wall Loss	ILI 2020 Number of Features	ILI 2024 Number of Features
		KP 0+323 – KP 6+342	KP 0+323 – KP 6+342
Internal Corrosion	> 50%	8.745	-
	40 % - 49%	8.486	-
	30 % - 39%	20.234	-
	20 % - 29%	51.126	-
	10 % - 19%	77.889	797
	Total	166.480	797

In the table above, compare the number of corrosion anomalies before and after insertion along 6 km. Data from ILI in 2020 shows that there are 166,480 features that exceed 10% of the thickness of the pipe, with 8,745 features exceeding 50% of the metal loss. Meanwhile, the results of the 2024 ILI inspection show that 797 features fall in the range of 10% - 19% metal loss. Partial replacement in 2023 eliminates internal corrosion attacks on 6 km of pipes, but in the following 1 year there have also been 797 cases of metal loss, which indicates that the internal corrosion demolition mechanism is actively running due to the presence of water as a corrosive electrolyte medium.

Furthermore, from the results of the FFS Assessment, the remaining life of the 12" subsea pipeline is determined. The remaining life calculation is performed for each segment by selecting the highest corrosion rate per joint for each section. From the calculation results, it has been found that the highest general corrosion rate is 0.46 mm/year (0.0185 inch/year), and the shortest remaining life is 12.8 years. This highest corrosion rate data is then used as the basis for the calculation of POF and subsequent risks.

3.2 Probability of Failure (PoF)

The calculation of POF using the structural reliability method is presented in the Table. 4 In the table, the relative POF value is seen as a function of the KM pipeline (KP). The KP selection was taken from each segment with the highest corrosion rate and wall thinning from the ILI results, with CR = 3 x 0.46 mm/year or 0.054 inch/year (assuming pitting corrosion). From **Table 4** seen for 2024, the maximum POF value of a subsea 12" pipeline is 2.18E-05.

Table 4. Data Pipeline and Failure Opportunity Calculation (POF) for 2024

			Design Basis						Pipeline Thickness Data		
No	KP	Nominal Thickness (Inch)	SMYSS (Psi)	SMYS$_{\text{Std Dev}}$ (Psi)	Diameter (Inch)	Pressure$_{\text{Avg}}$ (Psi)	Pressure$_{\text{Std Dev}}$ (Psi)	Wall Thinning or Corr Depth (%)	Max Corrosion Rate (Inch/Year)	Inspection Year	Current Thickness (Inch)
1	6909,582	0,500	52.000	13.000	12	250	25	0,26	0,0543305	2024	0,37
2	7640,114	0,500	52.000	13.000	12	250	25	0,20	0,0543305	2024	0,40
3	8109,733	0,500	52.000	13.000	12	250	25	0,22	0,0543305	2024	0,39
4	9787,022	0,500	52.000	13.000	12	250	25	0,23	0,0543305	2024	0,39
5	10090	0,500	52.000	13.000	12	250	25	0,23	0,0543305	2024	0,39
6	111136,213	0,500	52.000	13.000	12	250	25	0,23	0,0543305	2024	0,39
7	13917,032	0,500	52.000	13.000	12	250	25	0,20	0,0543305	2024	0,4
8	14952,484	0,500	52.000	13.000	12	250	25	0,29	0,0543305	2024	0,355
9	15482,625	0,500	52.000	13.000	12	250	25	0,29	0,0543305	2024	0,355
10	16235,429	0,500	52.000	13.000	12	250	25	0,28	0,0543305	2024	0,36
11	17105,471	0,500	52.000	13.000	12	250	25	0,26	0,0543305	2024	0,37
12	18011,275	0,500	52.000	13.000	12	250	25	0,25	0,0543305	2024	0,375
13	19204,33	0,500	52.000	13.000	12	250	25	0,23	0,0543305	2024	0,385
14	20742,348	0,500	52.000	13.000	12	250	25	0,28	0,0543305	2024	0,37
15	21160,384	0,500	52.000	13.000	12	250	25	0,25	0,0543305	2024	0,375
16	22545,134	0,500	52.000	13.000	12	250	25	0,29	0,0543305	2024	0,355
17	23345,945	0,500	52.000	13.000	12	250	25	0,29	0,0543305	2024	0,355
18	24136,911	0,500	52.000	13.000	12	250	25	0,28	0,0543305	2024	0,36
19	25862,659	0,500	52.000	13.000	12	250	25	0,28	0,0543305	2024	0,36
20	26628,444	0,500	52.000	13.000	12	250	25	0,28	0,0543305	2024	0,36
21	27918,836	0,500	52.000	13.000	12	250	25	0,33	0,0543305	2024	0,335
22	28010,675	0,500	52.000	13.000	12	250	25	0,29	0,0543305	2024	0,355

			Limit State Function Parameters & Calculation						Reliability Parameter		
No	KP	Nominal Thickness (Inch)	dg/d (SMYS)	dg/dP	dg/dt	μ_g SMYS (dg/d(SMYS))- μp (Hoop Stress)	σ^2_g	σ_g	Index Reliability (β)	Reability (Prob. of Failure Free)	Probability of Failure (PoF)
1	6909,582	0,500	0.72	-16,22	10956,90	33,386	87.794.243	9.369,9	3,5631	0,999817	1,83E-04
2	7640,114	0,500	0.72	-15,00	9375,00	33,690	87.765.079	9.368,3	3,5962	0,999839	1,61E-04
3	8109,733	0,500	0.72	-15,38	9861,93	33,594	87773.966	9.368	3.5957	0.999867	1,68E-04
4	9787,022	0,500	0.72	-15,58	10119,75	33,544	87773.966	9.368	3.5957	0.999867	1,72E-04
5	10090	0,500	0.72	-15.98	10139.75	33.544	87778.703	9.368	3.5803	0.999858	1,72E-04
6	111136,213	0,500	0.72	-15.98	10139.75	33.544	87778.703	9.368	3.5803	0.999858	1,68E-04
7	13917,032	0,500	0.72	-16.0	9375.0	33.69	87765.015	9.368	3.5631	0.999829	1,61E-04
8	14952,484	0,500	0.72	-16.07	9375.0	33.69	87765.015	9.368	3.5631	0.999829	1,97E-04
9	15482,625	0,500	0.72	-16.22	11902.4	33.215	87812.078	9.37	3.5445	0.999803	1,97E-04
10	16235,429	0,500	0.72	-16.17	11094.87	33.386	87808.85	9.37	3.569	0.999844	1,92E-04
11	17105,471	0,500	0.72	-16.07	11574.07	33.273	87805.85	9.37	3.5903	0.999863	1,83E-04
12	18011,275	0,500	0.72	-16.22	11902.4	33.215	87812.078	9.37	3.5445	0.999803	1,79E-04
13	19204,33	0,500	0.72	-16.17	11094.87	33.386	87808.85	9.37	3.569	0.999844	1,72E-04
14	20742,348	0,500	0.72	-16.07	11574.07	33.273	87805.85	9.37	3.5903	0.999863	1,92E-04
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16	22545,134	0,500	0.72	-16.17	11094.87	33.386	87808.85	9.37	3.569	0.999844	1,97E-04
17	23345,945	0,500	0.72	-16.67	13366.01	32.962	87840.282	9.372	3.5509	0.999782	1,97E-04
18	24136,911	0,500	0.72	-16.9	11902.4	33.215	87812.078	9.37	3.5445	0.999803	1,92E-04
19	25862,659	0,500	0.72	-16.67	11574.07	33.273	87805.85	9.37	3.5509	0.999803	1,92E-04
20	26628,444	0,500	0.72	-16.9	11902.4	33.215	87812.078	9.37	3.5445	0.999803	1,92E-04
21	27918,836	0,500	0.72	-16.67	13366.01	32.962	87840.282	9.372	3.5509	0.999782	2,18E-04
22	28010,675	0,500	0.72	-16.9	11902.4	33.215	87812.078	9.37	3.5445	0.999803	1,97E-04

Based on the POF calculation above, the KP with the highest POF at KP 27918,836 was taken to calculate the estimated change in POF as a time function from 2024 to 2030 for two damage mechanism scenarios, namely general corrosion and pitting corrosion as seen in table 5 and table 6 below. Pitting corrosion rate is assumed to be 3 x general corrosion rate in accordance with the recommendations of API 581 RBI. It can be seen that there is an increase in POF from 2024 to 2030, especially for pitting corrosion cases assuming the corrosion rate is constant. (Det Norske Veritas, 2017; Padmodwiputra et al., 2022)

Table. 5 POF Projections for 2024 – 2030) for Pipeline Locations with the Highest POF (Scenario I – *General Corrosion*)

Pipeline Risk Related to General Corrosion Rate

KP	Nominal Thickness Data	Design Data			Operational Data		Pipeline Thickness Data			
		SMYS (Psi)	SMYS Std Dev (Psi)	Diameter (Inch)	Pressure (Psi)	Pressure Std Dev (Psi)	Wall Thinning or Corr Depth (%)	Max Corr. Rate (Inch/Year)	Inspection Year	Predicted Thickness (Inch)
27918.836	0,500	52.000	13.000	12	250	25	0,33	0,0181	2024	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2025	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2026	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2027	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2028	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2029	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0181	2030	0,335

Pipeline Risk Related to General Corrosion Rate

KP	Pipeline Thickness Data	Limit State Function Parameters & Calculation						Reability Parameter		
	Inspection Year	dg/d (SMYS)	dg/dP	dg/dt	μ_g SMYS (dg/d(SMYS))-μp (Hoop Stress)	σ^2_g	σ_g	Index Reliability (β)	Reability (Prob. of Failure Free)	Probability of Failure (PoF)
27918.836	2024	0.72	-17,91	0,00	32,962	87.810.090	9.379,70	3,5176	0,999782	2,18E-04
	2025	0.72	-18,93	0,00	32,962	87.833.661	9.371,96	3,5171	0,999782	2,18E-04
	2026	0.72	-20,08	0,00	32,962	87.861.646	9.373,45	3,5166	0,999781	2,19E-04
	2027	0.72	-21,38	0,00	32,962	87.895.221	9.375,25	3,5159	0,999781	2,19E-04
	2028	0.72	-22,85	0,00	32,962	87.935.981	9.377,42	3,5151	0,999780	2,20E-04
	2029	0.72	-24,54	0,00	32,962	87.986.132	9.380,09	3,5141	0,999780	2,21E-04
	2030	0.72	-26,51	0,00	32,962	88.048.798	9.383,43	3,5128	0,999778	2,22E-04

Table. 6 POF Projections for 2024 – 2030) for Pipeline Locations with the Highest POF (Scenario II – *Pitting Corrosion*)

Pipeline Risk Related to General Corrosion Rate

KP	Nominal Thickness Data	Design Data			Operational Data		Pipeline Thickness Data			
		SMYS (Psi)	SMYS Std Dev (Psi)	Diameter (Inch)	Pressure (Psi)	Pressure Std Dev (Psi)	Wall Thinning or Corr Depth (%)	Max Corr. Rate (Inch/Year)	Inspection Year	Predicted Thickness (Inch)
27918.836	0,500	52.000	13.000	12	250	25	0,33	0,0543	2024	0,335
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2025	0,281
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2026	0,226
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2027	0,172
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2028	0,118
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2029	0,063
	0,500	52.000	13.000	12	250	25	0,33	0,0543	2030	0,009

Pipeline Risk Related to General Corrosion Rate

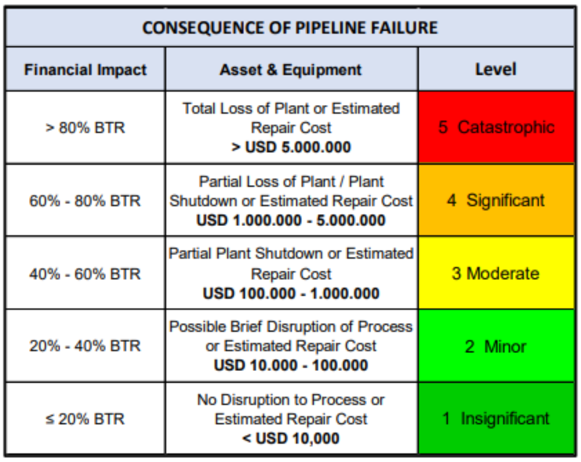
KP	Pipeline Thickness Data	Limit State Function Parameters & Calculation						Reability Parameter		
	Inspection Year	dg/d (SMYS)	dg/dP	dg/dt	μ_g SMYS (dg/d(SMYS))-μp (Hoop Stress)	σ^2_g	σ_g	Index Reliability (β)	Reability (Prob. of Failure Free)	Probability of Failure (PoF)
27918.836	2024	0.72	-17,91	13366,01	32,962	87.810.090	9.372.31	3,5170	0,999782	2,18E-04
	2025	0.72	-21,38	13366,01	32,962	87.925.418	9.376,86	3,5153	0,999780	2,20E-04
	2026	0.72	-26,52	13366,01	32,962	88.079.008	9.385,04	3,5122	0,999778	2,22E-04
	2027	0.72	-34,88	13366,01	32,962	88.400.313	9.402,14	3,5058	0,999772	2,28E-04
	2028	0.72	-50,99	13366,01	32,962	89.264.772	9.448,00	3,4888	0,999757	2,43E-04
	2029	0.72	-94,73	13366,01	32,962	93.248.384	9.656,52	3,4135	0,999679	3,12E-04
	2030	0.72	-666,25	13366,01	32,962	365.072.213	19.106,86	1,7252	0,957751	4,22E-04

Based on table 5 and table 6 above, a projection is made of the thickness value assuming a constant corrosion value. The corrosion mechanism used is in the form of general corrosion and pitting corrosion based on API 581. Where the pitting corrosion value is multiplied by 3 of general corrosion. And based on the results of the calculation projection, it is found that in 2030 the PoF value will increase significantly. This also happens in research (Witek, 2021). Where the degradation of the structural integrity of the pipeline shows a significant increase as the operating time increases, indicating a progressive process of material aging.

3.2 Consequences of Failure

To make the calculation of COF, it is taken from the experience experienced by PT. XYZ when there was a leak in the pipe, it was reported that the average loss value from two pipe leaks in 2019 was Rp. 14,653,083,679 / leak. This figure includes business loss components, repair materials, barge rentals, mob-demobs, etc. Quantitatively, the COF category used was taken from the HSSE of PT. XYZ with its COF category can be seen in the table below.

Table. 7 Failure Impact Range, COF, and Their Categorization



CONSEQUENCE OF PIPELINE FAILURE		
Financial Impact	**Asset & Equipment**	**Level**
> 80% BTR	Total Loss of Plant or Estimated Repair Cost **> USD 5.000.000**	5 Catastrophic
60% - 80% BTR	Partial Loss of Plant / Plant Shutdown or Estimated Repair Cost **USD 1.000.000 - 5.000.000**	4 Significant
40% - 60% BTR	Partial Plant Shutdown or Estimated Repair Cost **USD 100.000 - 1.000.000**	3 Moderate
20% - 40% BTR	Possible Brief Disruption of Process or Estimated Repair Cost **USD 10.000 - 100.000**	2 Minor
≤ 20% BTR	No Disruption to Process or Estimated Repair Cost **< USD 10,000**	1 Insignificant

3.3 Risk Assessment

The determination of the risk was obtained from the multiplication of POF x COF and then compared with two criteria. The calculation is carried out using pitting corrosion rate as the worst case scenario. Criterion no.1 is to compare the oil loss calculation for various un-planned shutdown conditions with the 5 x 5 risk matrix (**Table 2**). The risk calculation is carried out assuming that there is an improvement during t = 2 days of shutdown with a business loss value of USD 189,800 due to oil being wasted into the sea. Furthermore, the results of the risk calculation are shown in Table 8 for conditions in KP 27918.836. PT XYZ previous data showed that the value of losses every time there was a leak was IDR 14,653,083,679 or USD 976,872.

Table 8. Business loss (USD) in the event of an unplanned shutdown with various possible lengths of pipeline inability to deliver crude oil.

Shutdown Period	Flow Rate (Barrel)	Business Value USD
One Days	1.300	94.900
Two Days	2.600	189.800
Three Days	3.900	284.700
One Week	18.200	1.328.600
Note: Assumsing Crude Oil Price is USD 73/Barrel (Nov 2024)		

Table 9. Total financial risk (USD) as a function of time for pitting corrosion

Risk Assesment Result at KP 27918.836 Refer to Risk Matrix						
No	Tahun	Current Thickness (Inch)	Probability of Failure (PoF)	Consequence of Failure (USD)	Total Financial Risk	Risk Condition
1	2024	0,335	2,182306E-04	976.872	Risk Category III – Moderate (5-9)	Acceptable
2	2025	0,281	2,196351E-04	976.872		
3	2026	0,226	2,221849E-04	976.872		
4	2027	0,172	2,27586E-04	976.872		
5	2028	0,118	2,425785E-04	976.872		
6	2029	0,063	3,20688E-04	976.872		
7	2030	0,009	4,224936E-04	976.872	Risk Category IV Moderate to High (10 – 12)	Non-Tolerable

Table 9 based on the worst case scenario, namely. 1. Corrosion occurs in the pipe that undergoes the most severe thinning (in KP 27.9) 2. The corrosion rate is taken for pitting corrosion conditions with a rate of 3x general corrosion rate [9]. 3. The length of time for oil to be discharged into the sea is 2 days assuming the shutdown system and emergency response planning go well. In line with the growth of metal loss and the depletion process from 2024 to 2030,

it can be seen that the risk changes from moderate (level III) to moderate - high risk (level IV). It can be seen that changes will occur in 2028 to 2029.

Criterion no.2 is to compare the oil loss calculation for various un-planned shutdown conditions with the value of BTR = 5% x Net Profit, which is the maximum allowable risk value per year planned by PT XYZ (see **Table 10**).

Table. 10 Maximum allowable risk values

BTR = 5% x Net Profit		
NET Profit Tahun 2024	USD	93.910
Basis Trading Risk (BTR)	USD	4695,5

The risk of loss is calculated for 2024 to 2030 and its value is compared to BTR USD 4695.5. Next, the results of the risk calculation are shown in Table 11 for conditions in KP 27918.836.

Table. 11 Risk profile as a function of time (Ref: BTR)

Risk Assesment Result at KP 27918.836 Refer to Annual Maximum Acceptable Value (BTR)						
No	Tahun	Current Thickness (Inch)	Probability of Failure (PoF)	Consequence of Failure (USD)	Risk (USD)	Max Allowable Risk Value (BTR)
1	2024	0,335	2,182306E-04	976.872	213,18	Acceptable
2	2025	0,281	2,196351E-04	976.872	214,56	
3	2026	0,226	2,221849E-04	976.872	217,05	
4	2027	0,172	2,275866E-04	976.872	222,32	
5	2028	0,118	2,425785E-04	976.872	236,97	
6	2029	0,063	3,20688E-04	976.872	313,27	
7	2030	0,009	4,224936E-04	976.872	41.272,22	Non-Tolerable

Along with the increase in metal loss and the process of depletion of the pipeline wall from 2024 to 2030, there is a change in the level of risk from the acceptable category to the non-tolerable category, as shown in Table 11.5. This significant change is seen in 2029 towards 2030, where the risk value has decreased from USD 313.27 to USD 41,272. Until 2029, the risk value is still below the Basic Target Risk (BTR) so it is still acceptable. However, by 2030, the risk value exceeds the BTR threshold, indicating that the risk is no longer tolerable.

In contrast to the first risk assessment criterion, where the change in risk occurs gradually from the yellow to orange category, in the second criterion the transition occurs directly from the green category (acceptable risk) to red (unacceptable risk)). Nonetheless, from an operational technical perspective, the two assessment approaches show equal meaning and conclusions.

The two assessment criteria consistently yield the same conclusion, namely that after 2030, the level of risk has exceeded the permissible tolerance limit. Therefore, it is necessary to implement a comprehensive Inspection, Maintenance, and Testing (IMT) strategy to mitigate these risks. It should be noted that the risk calculation presented above is based on a conservative approach, so it still contains an inherent safety factor.

3.3 Recommendations of Inspection, Maintenance & Test (IMT) Plan

In order to effectively mitigate risks, it is necessary to plan a comprehensive and structured Inspection, Maintenance, and Testing (IMT) strategy. This approach provides visualization of the logical flow starting from hazard identification to the implementation of mitigation measures aimed at reducing potential production losses.

Furthermore, the IMT strategy is shown in detail in Table 12, which outlines risk control approaches to various forms of threats to the safety of pipeline operations. This strategy includes both time-dependent threats such as internal and external corrosion, as well as time-independent threats such as the mechanical impact of third-party interference (e.g. anchor drops or pulling), as well as potential geological hazards (geohazards). This approach aims to maintain the integrity of the piping system through risk management based on relevant threat characteristics.

The recommended corrosion control strategy includes regular cleaning pigging and injection of corrosion inhibitors combined with biocides, to prevent corrosion and microbiologically induced corrosion (MIC). Furthermore, it is necessary to develop a Pipeline Integrity Management System (PIMS) as a systematic framework in carrying out all aspects of risk mitigation that are time-dependent and non-time (time-independent threats), including external threats such as mechanical impacts from third parties and potential geohazards, so that pipeline integrity management can be carried out in a sustainable and risk-based manner.

Table 12. Inspection, Maintenance and Test Plan

No	Threat or Risk	IMT Classification	IMT Method	Purposes	Recommended Time Interval	Remarks
1	Internal Corrosion Causing Pipeline to Leak	Direct Integrity Inspection	Inline Inspection (ILI)	To determine the metal loss of pipeline wall thickness	5 years (based on QRA result)	Inspection time is governed by the QRA or RL. The inspection time interval is 50% x 12.7 years = 6 years.
2		Corrosion Control	Corrosion inhibitor and biocide injection	To reduce internal corrosion by creating film on the internal pipeline surface	Weekly or Depending on the need.	These chemicals can be a cocktail to reduce both corrosion and microbiology induced corrosion (MIC)
3		Periodic Monitoring	Fluid Composition Analysis	To estimate the internal corrosion threat by measuring the corrosive gas (CO_2) if any	Quarterly (Every 4 monthly)	Check for the increase of CO_2, O_2 or water content if any
4		Periodic Maintenance	Cleaning Pigging	To remove any carried-out water or condensation, corrosion products and scaling.	Monthly or according to PT XYZ SOP	Depending on the Case related to Fluid Composition as in No.7 above
5		Periodic Monitoring	Debris Composition Analysis	To estimate the internal corrosion threat by determining the debris composition and quantity, as a follow up of cleaning pigging results	Quarterly (Every 4 monthly)	This is related to cleaning pigging operation, to check for the possible increase of Fe^+ ions or other corrosion product (Fe_2O_3, Fe_3O_4, etc)
6	External Corrosion Causing Pipeline to Leak	Direct Integrity Inspection	Inline Inspection (ILI)	To determine the metal loss of pipeline wall thickness	5 years (based on QRA result)	Inspection time is governed by the QRA or RL. The inspection time interval is 50% x 12.7 years = 6 years.
7	External Corrosion Causing Pipeline to Leak Free span due to Geohazard and Seabed Movement	Indirect Inspection	Cathodic Protection Inspection	To determine the coating effectiveness or damage and possible external corrosion attack	5 years	Time interval can also be determined from, subsequently, 25% - 50% - 75% of sacrificial anodes design life of 25 years

8		Under Water Inspection	Side Scan Sonar (SSS) & MBES, and/or ROV	To inspect any possible free span or pipeline displacement and to measure the length, if found to be the case	5 years	Depending on risk level and as response to geohazard events (e.g. tsunami, earthquake, storm or else). Therefore, it is conditional.
9	Third Party Damage (Anchor Drop and Drag	Under Water Inspection	Side Scan Sonar (SSS) and/or ROV	To inspect any possible buckling and or/bend and to measure the length and radius, if found to be the case	Case by Case	This is time independent event threat, and therefore, to be case by case only. Therefore, it is also conditional.
10	Third Party Damage (Anchor Drop and Drag	Prevention	Patrol and Navigation Buoy	To encourage vessel or ship anchoring in forbidden areas (pipeline ROW)	Patrol – Weekly or depending on PT XYZ SOP Buoy is 24 hours/day	Signs or Means of Navigation Aid for Shipping
11	As followed up if point 8 and 9 occur (Free span and Anchoring Damage)	Under Water Inspection	ROV	To inspect more closely anomalies related to pipeline damages (dent, leak, free span, buckle, etc). As a followed up of SSS inspection previously conducted.	Case by Case	This is time independent event threat and therefore, to be case by case only.
12	Operational Error Leads to Over Pressure	Functioning Test	Topside Pressure ESDV Testing	To check the reliability of ESDV case of failure on demand (fail to open)	Annually	This test is performed at offshore platform

4. Conclusion

A risk assessment has been carried out on the 12-inch diameter subsea pipeline along 28.7 km. The methodology used in this analysis adopts the First-Order Second-Moment (FOSM) approach of structural reliability, which functions as a counterpart to the process safety method. By referring to PT.XYZ 5 × 5 risk matrix and acceptable risk threshold values (expressed in USD), the evaluation results show that the risk level of the subsea pipeline is in the *moderate* category (Level III) and is still within acceptable limits until 2029, assuming a constant corrosion rate of 0.46 mm/year according to the results of the previous FFS evaluation. However, by 2030, the risk level is projected to increase to the significant (Level IV) or non-tolerable category, mainly due to the dominant damage mechanism in the form of localized pitting corrosion. For calculating conservatism, an internal corrosion approach of three times the normal rate (3 × 0.46 mm/year) as recommended by API 581 is used (American Petroleum Institute, 2020).

Based on these results, risk mitigation strategies need to be comprehensively prepared through integrated inspection, maintenance, and testing (IMT) planning. One of the study's key findings suggests that In-Line Inspection (ILI)-based inspections do not need to be carried out every three years as recommended in the previous FFS study, but can be rescheduled until 2029, without compromising safety and integrity aspects. This shows the potential for efficiency in operational and maintenance costs through the Risk-Based Inspection (RBI) approach. Given that internal corrosion is a major risk factor for leakage, the recommended corrosion control strategy includes regular cleaning pigging and injection of corrosion inhibitors combined with biocides, to prevent corrosion and microbiologically induced corrosion (MIC). Furthermore, it is necessary to develop a Pipeline Integrity Management System (PIMS) as a systematic framework in carrying out all aspects of risk mitigation that are time-dependent and non-time (time-independent threats), including external threats such as mechanical impacts from third parties and potential geohazards, so that pipeline integrity management can be carried out in a sustainable and risk-based manner.

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