The Risk Identification on 3" GL BO3-52520 Process Pipelines Using A Risk-Based Inspection Method

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Article Info

Article history:

Received Mar 21th, 2022
Revised Apr 15th, 2022
Accepted May 19th, 2022

Keywords:

Risk-Based Inspection
Offshore
Glycol Service Line

ABSTRACT

The oil and gas industry can contribute significantly to sustainable development by mitigating negative environmental impacts, such as equipment failure. Numerous pipeline failures have occurred due to the dramatic expansion of the oil and gas product distribution pipeline network, which is a significant factor in the offshore gas pipeline network's failure. In general, compared to other equipment types in the industry, planning inspections presents more challenges. Due to a lack of jurisdictional requirements regarding inspection intervals and piping methods. This research aims to ensure the reliability by conducting a risk assessment of the likelihood and consequences of equipment failure, mitigating the impact of that risk, and developing a more optimal inspection plan. This study is focused on API Class 5L Pipe 3" GL BO3-52520. The Routine Inspection Technique (RBI) was implemented in 2016 following the API 581 standard. This semi-quantitative approach is built based on operational data and validated inspection results. According to the risk assessment, the pipeline will have a medium risk level, with metal losses occurring in each segment. Four years after the risk-based inspection assessment, the recommended inspection plan for gas pipelines is four years.

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1. INTRODUCTION

The piping system is a method of transporting fluids between pieces of equipment (equipment) in a factory or from one location to another to carry out the manufacturing process [1]. Pipes, valves, fittings (elbow, reducer, tee), flange, nozzle, instrumentation (equipment for measuring and controlling fluid flow parameters such as temperature, pressure, mass flow rate, and altitude level), equipment (heat exchangers, pressure vessels, compressor pumps), pipe supports (pipe support and pipe hangers), and special components are included in the piping system (filters, drains, vents). In the industrial world, piping and pipelines are used as the piping system. Piping is a piping system used in a plant to transport fluids (liquid or gas) from one piece of equipment to another to complete certain processes. This piping will not originate from a single plant area. At the same time, a pipeline is a piping system used to transport or drain fluids between plants that typically pass-through multiple regions [2]-[3].

Damage and piping leakage are frequently encountered problems, which can impair operating conditions and the refinery's production process due to leakage and damage to piping. Pipe damage and leaks are repaired and replaced with identical specifications and dimensions. Pipe corrosion is monitored and mapped. However, pipe damage and leakage remain a common occurrence. The results of the problem's identification indicate that one of the contributing factors is a lack of standard piping engineering inspection procedures that can be used as work guidelines and instructions for performing the duties and work of piping engineering inspections. As a result, maintenance activities are required to ensure that components or systems can perform their intended functions. Further analysis of the corrosion rate, residual life, and risk level can be used to estimate a more targeted pipeline inspection plan program.

By utilizing the Risk-Based Inspection (RBI) method, you can develop an inspection program or plan based on the risk of equipment failure and the associated consequences/consequences. RBI risk is defined as the product of a failure probability and a failure consequence [4]. RBI can classify a transaction as high, medium, or low risk and then focus its examination on the high-risk transaction. The RBI planning process is based on risk assessment and utilizes flexible inspection intervals and scopes (audit methods or procedures). The use of pressure vessels and pipelines in determining equipment risk and planning inspections with RBI in the form of inspection schedules and schemes. And can use RBI to classify the level of risk in gas to determine which equipment needs to be inspected immediately or what actions can be taken to mitigate potential risks. The equipment is analyzed in this study is the Piping inlet Glycol Flash Drum used in the oil and gas processing industry. Table 1 contains summary data from the tools analysed.

Table 1: General information of tools

Equipment	Pipe (Glycol service line)
Tag No.	3" GL BO3-52520
Design Press/Temp	145psi / 1500C
Diameter	18”

Due to the prioritization of inspection on high-risk equipment, a study of tool results by the RBI can help cut maintenance costs more effectively. This is the context of this study, which is analyses inspection data to determine a risk-based inspection of the Glycol Flash Drum Piping intake in order to prevent leaks and fires. Whereas the most recent advancement in this research is the analysis of inspection data for calculating risk-based inspection on the Glycol Flash Drum Piping inlet using a quantitative approach to the API 581 standard.

2. METHODS

The research is focused on piper export of PT X, which is connected to the subsea gas pipeline at an offshore facility. The pipe specifications are SMLS ASTM A53 Gr.B standard with a nominal diameter of 18-inch. Research data is based on in-line inspection reports (ILI) using high resolution Magnetic Flux Leakage (MFL). The risk assessment is carried out based on a quantitative approach to risk-based inspection according to the 2016 API 581 standard by analysing and evaluating the corrosion rate from the ILI inspection data.

2.1 Risk-based inspection

Risk-Based Inspection (RBI) is a relatively new inspection technique. This method is based on risk analysis, which entails determining the probability of a failure, the magnitude of the risk effects associated with the loss, and the relationship between the failure and the operating system in use [6]. RBI is a risk-based inspection technique in which hazards are used to prioritize and manage the inspection program [7]. A sizable portion of the risk in operational factories is associated with equipment items. RBI enables a reallocation of inspection and maintenance resources to provide a higher level of safety through coverage of high-risk items and the effort required to mitigate the risk of those hazards with good equipment. The RBI program's potential benefit is to extend the life of the equipment and run industrial facilities with a long process to minimize failures or at the very least maintain the same level of risk [8]. The RBI method defines operating equipment risk as to the multiplication of the consequences of failure and the probability of failure. Thus, the risk is determined by the RBI as Equation 1 [9].

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

2.2 Probability of failure (PoF)

The two components of the Probability of Failure (PoF) are calculated following the applicable SOP. Two elements are calculated semi-quantitatively for PoF analysis: the probability of failure and the consequences of failure. The likelihood of failure is the likelihood of an item of equipment or component failing [10]. The occurrence of a loss in the element being analysed is determined by its current operating condition.

DOI: *https://doi.org/10.24036/teknomekanik.v5i1.12772*

Table 2: Probability category

Remaining Life (RL)	*Probability of Failure (PoF)*	
RL ≤ 4 year	High	5
4 < RL < 6 year	Medium-High	4
6 < RL < 8 year	Medium-Low	3
8 < RL < 10 year	Low	2
8 < RL < 10 year	Very Low	1

2.2 Consequence of failure (CoF)

The term "Consequence of Failure" refers to the effect or consequence of equipment failure [11]. API 581 defines two methods for determining failure consequence analysis: level 1 and level 2. At level 1, consequence analysis is simplified and is used for fluids included in the API 581 representative fluid list. While level 2 is more precise and can be used with a broader range of liquids, level 3 is more detailed and can be used with a wider range of fluids. This level is used if level 1 is not applicable and the equipment is equipped with a two-phase fluid [12].

Table 3: Stand by availability (S)

***Stand by availibility* (S)**	***Rating***	
Emergency Shutdown (Stop Production)	High	5
Reduction max. 20%	Medium-High	4
Reduction max. 10%	Medium-Low	3
Reduction max. 5%	Low	2
There is no reduction in production.	Very Low	1

If there is a pipe failure and data on time required to repair it and the cost involved, we can determine the Rating Financial Model.

Table 4: Financial model (F)

Financial Model (F)		**Rating**	
Repair Time (M)	**Cost (B)**		
M ≥ 7 day	B ≥ Rp. 1M	High	5
5 ≤ M < 7 day	Rp. 500 million ≤ B < Rp. 1M	Medium-High	4
3 ≤ M < 5 day	30-50% BTR	Medium-Low	3
1 ≤ M < 3 day	10-30% BTR	Low	2
M ≤ 1 day	B<10% BTR	Very Low	1

To determine COF, we must also have equipment monitoring data to determine the rating of the Model Location (Safety & Environment) [13].

Table 5: Model location (Safety & Environment)

Location (L)	***Rating***	
Public Areas, densely populated	High	5
Public Area, far from residential	Medium-High	4
General location and can be monitored	Medium-Low	3
Inside cluster but not fenced	Low	2
Cluster, fenced, there is security	Very Low	1

3. RESULTS AND DISCUSSION

3.1. In-Line inspection (Report)

Risk data is collected during in-line inspection activities using a high-resolution MFL. Metal loss, remaining life, and MAWP are all included in the data obtained. According to ILI inspection data, only the splash zone segment exhibits corrosion and decreased pipe thickness. Corrosion is indicated by the data from the piping and the operating parameters of the service piping. Segment 5 has the highest corrosion rate of 0.95. Metal loss in the splash zone segment occurs at 64 percent of the initial thickness. However, because the splash zone segment is less than 80% of the nominal pipe wall thickness, it is considered safe to operate below the maximum allowed thickness standard. On the other hand, PT X increased the safety margin to 70% of the nominal pipe wall thickness.

Table 6: Inspection data calculation results

Segment	Corrosion Rate	Remaining Life	MAWP
1	0.48	19.11	4413
2	0.76	11.7	4211
3	0.44	20.94	4310
4	0.66	13.62	4242
5	0.95	9.16	4151
6	0.83	10.63	4189
7	0.85	10.36	4182
8	0.79	11.22	4201
9	0.69	12.79	4229
10	0.66	13.62	4242
11	0.32	29.16	4348
12	0.39	23.75	4326

3.2. Probability of failure

The probability is calculated using the API 581 standard's 2016 equation [16]. Component type PIPE-16 is used to calculate the total generic failure frequency (GFF total). A total score of 500 was assumed for the factor management system. Based on the ILI examination data, mediation of the damage mechanism revealed that only thinning and external mechanisms occurred. The pipe corrosion rate is calculated for each segment by comparing the initial and actual thickness over a specified period [14]. Corrosion is happening at 0.95 mm/year in the splash zone segment. The ASME B31.4 standard can be used to determine the minimum allowable pipe thickness. The wall loss fraction of the component pipe (Art) was calculated using the actual thickness, corrosion rate, and time difference between the last inspection and the current RBI [15]. Each pipe segment is classified differently; the splash zone segment is classified as 5 due to its reduced thickness and external corrosion. On the other hand, the upper and lower reaches of the water are classified as category 2 due to the absence of pipe wall thinning and corrosion problems. By calculating the corrosion rate, we can determine the pipe's remaining life, which is 9.16 years, for which the POF ranking is Low (2).

3.3. Consequence of failure

The consequences of failure are determined by the area affected by the pipeline's failure and are calculated following the API 581 standard's section 3 calculation of consequences. Numerous assumptions are made when calculating the consequences of failure [16].

1) Consequences are quantified using an area-based risk approach.
2) The analysis is performed using level 1 consequences.
3) The mass released per minute ranged between 45.4 kg and 45.3592 kg.
4) Holes for leaks

The consequences of failure are determined by comparing the maximum value of total component damage to the number of personnel injured [17]. According to the data, if there is damage to the meal, the maximum production will be reduced. 20% with a repair time of 5 M 7 days and Rp. 500 million B Rp. 1 million. There is a cluster at the location, it is fenced, and there is security. COF is ranked according to the results of the RBI analysis, as shown in the following table:

Table 7: Consequence of failure

	Ranking					COF
	1	2	3	4	5	
Stand by Availability (S)				X		Significant
Financial Mode (F)				X		(D)
Location (L)	X					

The result of each pipe segment failing is predicted to be Significant. The COF categories for each pipe segment are identical because they are running on the same operating system. As a result, the input data used in the analysis is also similar.

3.3. Risk ranking

The approach used to calculate POF and COF results in different risk ratings for each segment. The pipeline segment located in the splash zone carries a Low-risk rating (2). Further investigation revealed that the disparate ratings for the gas pipeline segments resulted from a breakdown mechanism. There is a loss of pipe wall thickness and external corrosion in the splash zone segment. As a result, the consequence of failure is significant (D). We plot the POF and COF values into a 5x5 matrix to determine the existing risk conditions.

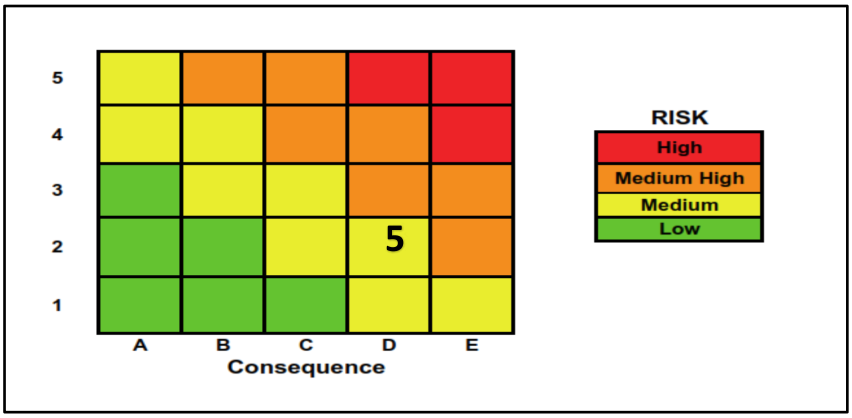

Figure 1: Risk matrix

3.4. Inspection planning

The term "inspection planning" refers to how defined risk targets are determined. The 2016 API 581 standard does not describe in detail or equation specificity how to plan an inspection schedule; rather, it is illustrated graphically [17]. To develop an inspection plan, certain assumptions are made:

1) Establishing risk objectives
2) The company has established a ten-year inspection plan from the date of the last inspection.
3) Determination of inspection plan based on High-risk equipment.

Meanwhile, the company has determined to determine the company's inspection schedule using critical comparison data from the risk matrix with company-level confidence.

1) Code 4 = no confidence or no data
2) Code 3 = predictable deterioration and incomplete data
3) Code 2 = predictable deterioration, standard accepted defect data, and complete data
4) Code 1 = no active failure mechanism, stable operating environment, and complete data

DOI: *https://doi.org/10.24036/teknomekanik.v5i1.12772*

Table 8: Determination of inspection interval

	Risk	Confidence Level			
		4	3	2	1
9	High Risk	1	2	6	N/A
8		2	4	6	N/A
7		3	4	6	N/A
6	Medium Risk	4	4	8	8
5		4	6	8	8
4		6	6	8	10
3	Low Risk	6	8	10	10
2		8	10	10	15
1		8	10	15	15

The confidence level is used for code 4 because it lacks accurate data, implying that the existing data is unreliable [19]. According to the table above, the inspection interval is four years.

4. CONCLUSION

According to the RBI method for piping system number 3, GLB03-52520 has a Remaining Life of = RL 9 years, indicating a Low Probability of Failure (PoF) (2) and a Medium-High Rating for Consequences of Failure (CoF) (4) based on the multiplication of standby availability, location, and financial. The consequences of failure are similar for each segment due to the influence of operating data. Corrosion-related environmental effects affect the probability of failure in the spark zone segment [20]. Reduce failure risk by enhancing the effectiveness of pipe inspection and reinforcement through the wrapping method. The inspection plan for gas pipelines that use the in-line inspection method is recommended to be one year from the date of the risk-based inspection assessment, which is every four years.

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