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Estimating Remaining Life and Fitness-For-Services Evaluation of Fuel Piping Systems

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Abstract. Assets life extensions are required to predict the design life expiry based on condition and effects of deterioration. The remaining life assessment will answer the questions about the timing of the component or equipment that will lead to failure and shall be evaluated by inspection and maintenance monitoring. This study elaborates on process calculation and analysis by using the remaining life assessment and fitness for services method according to API 579-1/ASME FFS-1 for the process piping area. The result of remaining useful life estimation and estimated life has been proposed. There are 11 piping systems based on condition monitoring with thickness measurements. The result is that 2 piping systems were not reached more than 20 years of age and continue to the assessment of fitness for service. The result for Inlet Naphtha 946-TK-5 piping systems is accepted for assessment level 1, both in evaluating average measured criteria and minimum measured thickness. The piping systems can continue the operation until the estimated life. Another result for the Discharge of Crude 946-P1AB to CDU piping systems was not accepted due to the minimum measured thickness not meeting the criteria. Hence, the piping systems are potentially unsafe with the given data during the lifetime.

Keywords: Piping, Remaining Life Assessment, Remaining Useful Life, Fitness For Services, Plant Life Extension, Corrosion, Damage Mechanisms, Oil and Gas.

INTRODUCTION

The role of asset integrity management in the asset life cycle affects each project stage. In the conceptual project process, the selection of materials for the equipment is determined based on applicable codes and standards, then a hazard analysis is also carried out using the HAZID and safety integrity level methods. In the Front-End Engineering Design (FEED) process, the role of asset integrity management is to create process safety management-related operating procedures to avoid potential failures, create asset registers, and identify service fluids and their materials as an input to create corrosion circuits. In the operational stage, monitoring and inspection are carried out to determine the performance of equipment and take action if there is a deviation between the design and the actual operating conditions [1]. The operational stage has an average life of 20 years after commissioning. Operation and maintenance are needed because of the potential of assets degradation over time due to ageing mechanisms, which are corrosion, erosion, fatigue, embrittlement, and others. Several incidents due to ageing facilities are leaking, cracking, blistering or damage, and equipment system failure. The main accelerate factors which caused degradation in facilities are operating conditions, extreme environment, design integrity, quality of welding joints, and lack of consistency for inspection and assessment. The ageing facility allows rejuvenation to be carried out through evaluations such as inspection and assessment [2].

Life extension in ageing facility depends on the ageing process, including material degradation and organizational issues. The degradation process, assets data in real conditions, and evaluation methods will lead to an implementation strategy during the extended life. Several research has been done to assess the equipment to operate safely during extended life using fitness for services. The procedure evaluates the strength of equipment or component in actual condition with the calculation of maximum allowable working pressure, RBI methodology approach, and fitness for services. Although the literature is relevant to give recommendations on whether the equipment will be repaired, replaced, or modified, the research focuses on evaluating all equipment without knowing the remaining life of the component [3,4,5,6]. In this sense, this study elaborates on process calculation and analysis using the remaining life assessment and fitness for services method according to API 579-1/ASME FFS-1 for the process piping area. Evaluation of asset condition and assessment of remaining useful life is one of the stages and activities in life extension process management. The estimation of remaining useful life is based on asset data collection, evaluation of damage mechanisms, information condition, inspection monitoring, design record, and repairs performed. The result of estimating remaining useful life is to support the process of life extension strategy with the implementation of monitoring, maintenance, or modification, and also change the future process or operation parameter applicable to the equipment and component [7].

The assessment has to take into consideration many factors, which are historical and future operating regimes, materials of construction properties, current active damage mechanisms, and previous inspection results. The remaining life can be determined based on the minimum required thickness according to B31.3, thickness measurements from historical data inspection, and the corrosion rate. The corrosion rate should be calculated from measured thickness data from recorded thicknesses over time at condition monitoring locations (CMLs). The data obtained from the inspection results in the form of thickness measurements will be processed to become data input in the remaining life assessment [8,9].

The target of the life extension is 20 years from now (the year 2043) due to the equipment end of life condition was a critical factor in the assessment, which not be expected to be as new, and their service life can be extended in accordance with the results of the analysis by prioritizing safety factors. The equipment which has exceeded the design service life limit may continue to be used after carrying out a remaining life assessment and it is declared. The piping section will be identified which will be safe to continue the operation until 2043, or alternatively unsafe for the next 20 years. The piping which was found to be potentially unsafe will be subjected to a life extension strategy. These activities and decisions use Fitness-for-services (FFS) assessments.

The FFS assessments are conducted to assess the structural integrity of a component, and its suitability for continued service under the same or changing conditions. It will identify the ageing potential threats as a damage mechanism, so it can be prevented and mitigated. Procedures such as API 579/ASME FFS-1 enable the integrity of critical components and welded structures to be assessed against different failure modes, using a validated engineering approach. In principle, the fitness for services would begin with a Level 1 assessment, if it is failed, then the Level 2 assessment would be undertaken. If it is not meet the qualification and criteria, then the Level 3 assessment shall be considered. Implementing the FFS assessment results in the decision to continue running the equipment or component as usual, repair or replace it, and change the operating parameters or continue to use it [10].

The assessment techniques for fitness for services in API 579 addressed twelve different damage mechanisms, which are brittle fracture, general metal loss, local metal loss, pitting, hydrogen blisters, HIC, SOHIC, weld misalignment, and shell distortion, crack-like flaws, creep, fire damage, dents and gouges, laminations and fatigue [11]. Therefore, before conducting the FFS assessment, it is necessary to identify the damage mechanisms.

The following are the potential damage mechanisms in the units of piping systems, atmospheric corrosion is a form of corrosion that occurs from moisture associated with atmospheric conditions. In addition, corrosion under insulation (CUI) of piping occurs due to the water trapped under insulation or fireproofing. It will affect externally insulated piping and equipment with service between -12ºC and 175ºC for carbon steel and alloy steels, and 60ºC and 205ºC for austenitic stainless steels and duplex stainless steels where water evaporates quickly and become trapped. High-Temperature Acidic/Naphthenic Acid Corrosion is a form of high-temperature corrosion that occurs primarily in crude and vacuum units. NAC can be occurred in carbon steel and normally occurs in hot streams above 425ºF (218ºC). The NAC causes localized corrosion, pitting corrosion, or flow-induced grooving in high-velocity areas of the internal piping system. Hydrochloric acid (aqueous HCl) also causes excessive general and localized corrosion when exposed to carbon steel with a pH below 4.5 [12].

Stress corrosion cracking which caused by environmental cracking of 300 Series SS and some nickel base alloys under the combined action of tensile stress, temperature, and an aqueous chloride environment. The presence of dissolved oxygen increases the propensity for cracking. Another damage mechanisms are fatigue cracking, which is a mechanical form of degradation that occurs when a component is exposed to cyclical stresses for an extended period, and the failure was unexpected. Creep at high temperatures, metal components can slowly and continuously deform under load below the yield stress. The rate of creep deformation is a function of the material, load, and temperature. The threshold temperature can be seen in API 571 Damage Mechanisms [13].

The damage mechanism will also affect the corrosion rate. The ability to state corrosion rate is limited by the equipment complexity, process, and metallurgical variations. The best information comes from inspection results for the current equipment process operating condition. In general thinning, the corrosion rate is based on the fluid where the presence of CO_2 or H_2S in crude oil fluids and the presence of gas with CO_2 with partial pressure above 3 psi will accelerate the corrosion rate. The complexity of the branch connections on the pipe, coupled with the presence of sand or debris in the fluid, will lead to erosion which causes internal thinning and a higher degradation rate. The high corrosion rate reflects the total metal loss of thickness pipe, which will affect the result of minimum measured thickness at the circumferential and longitudinal planes in the pipe. The average measured thickness obtained from the results of historical data inspection will be computed and compared with the minimum required thickness in API 579 fitness-for-service. Therefore, the estimated life and fitness-for-services assessment depends on the input parameters between operating conditions, thickness measurement, and corrosion rate of the components [14].

Fitness for services assessments on pipes related to corrosion, it is necessary to give attention to several things, such as internal and external corrosion, where the effect is caused by a metal loss that occurs on the outside and inside of the pipe. Internal corrosion can be measured using ultrasonic testing thickness to determine the remaining wall thickness of the pipe, while external corrosion can be measured using pit gauges. In addition, it is also necessary to give attention to whether the damage mechanisms that occur are uniform corrosion or localized corrosion because the effect of pitting on localized corrosion has a different assessment, namely by measuring the depth of the pit [15].

MATERIALS AND METHODS

The framework for the assessment applied in this study is summarized in **FIGURE 1**. This procedure is mainly based on the required data gathering as a current condition and the historical data about design, operation, maintenance, and inspection report will be reviewed. The document and information will be collected as an asset register. The data was collected from the design data, manufacturing data, service data, operation and maintenance history, the last operating conditions, and the results of inspection for each period. The corrosion rates are identified from inspection results trending based on the wall thickness measurement and other published documents. The remaining useful life or remaining life assessment stage is a determination of whether the equipment has a residual life of more than 20 years or not. Prior to the fitness for a service assessment, a damage mechanisms review will be conducted. All potential and future active damage mechanisms will be identified. Fitness for service assessment procedures can be used to qualify a component for continued operation or for rerating.

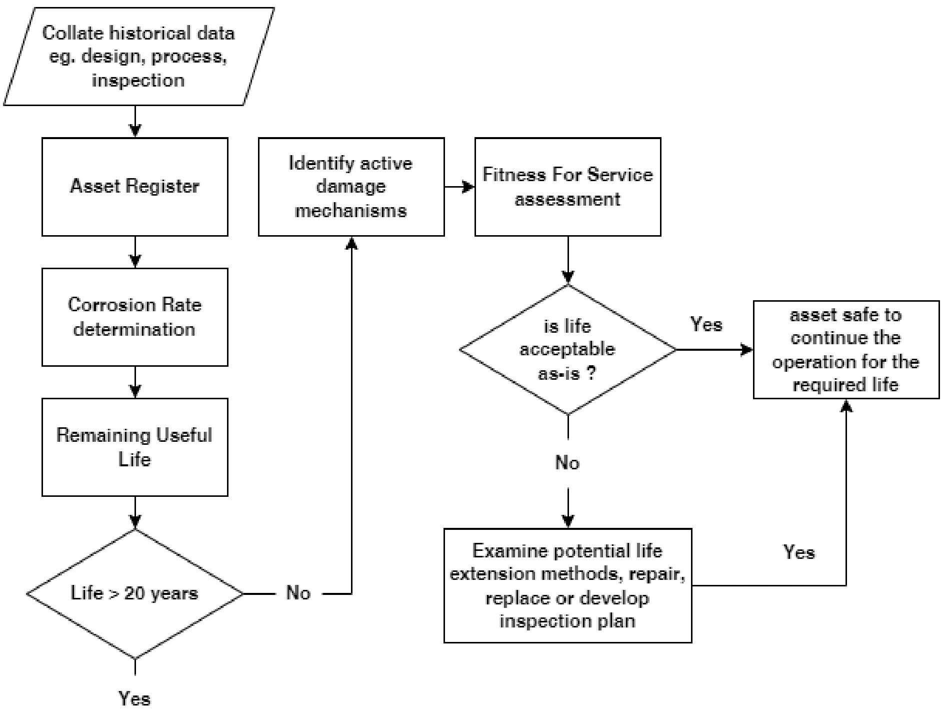

FIGURE 1. Plant life extension study framework.

Asset Register

The piping system installation in this study is used to distribute fluids or products located in the Riau province area for fuel needs, such as Naphtha, Kerosene, Automatic Diesel Oil, and Low Sulfur Waxy Residue. This piping data was collected from technical data and service in storage tank lines. The following function of this piping system is to send the product to be accommodated into the storage tank based on the specifications that have been produced, receive the production result of fluids, carry out transfers between tanks for the product blending process, or serve requests from the marketing directorate via line, tank cars, and ships. Receipt of crude oil comes from the upstream industrial refinery. The facility has two piers or jetties to facilitate the reception of sea lanes. Therefore, the piping system to the jetty is also included in the asset register. The piping component was registered and broken down into the asset components: pipe and elbow. The following data are unit process flow diagram (PFD), piping and instrument drawing (P&ID), piping isometric drawings, technical data books such as datasheets or drawings, materials and specifications, operating condition, and fluid compositions shown in **TABLE 1. a** and **TABLE 1. b.**

TABLE 1.a Asset register of piping systems

No.	Line Name	Service Fluid	NPS	WT (mm)	Length (mm)	Material	CA (mm)
1	Inlet Naphtha 946-TK-5	Naphtha	4	6.02	10750	SA-53 Grade: S/B	1.6
2	Inlet ADO Product 946-TK-06	ADO	4	6.02	13710		1.6
3	Inlet ADO Product 946-TK-07	ADO	4	6.02	19910		1.6
4	Suction ADO Product 946-TK-07	ADO	8	8.18	6720		1.6
5	Discharge Crude 946-P1AB to CDU	Crude	8	8.18	59800		3.2
6	Inlet Kerosene Product 946-TK-20	Kerosene	10	9.27	70600		1.6
7	Kerosene Product 946-TK-19	Kerosene	10	9.27	27410		1.6
8	Suction Load Kerosene 946-TK-20	Kerosene	14	11.12	111900		1.6
9	Suction Load Kerosene Prod 946-TK-19	Kerosene	14	11.12	28500		1.6
10	Suction ADO Product 946-P-2D	ADO	14	11.13	27850		1.6
11	Loading Residue Discharge Crude from Jetty	Crude	20	15.09	48500		1.6

Note: NPS - Nominal pipe size, WT - Wall thickness, CA - Corrosion allowance, ADO - Automatic diesel oil, CDU - Crude distillation oil.

TABLE 1.b Asset register of piping systems

No.	Line Name	Design Pressure (bar)	Design Temperature (ºC)	Operating Pressure (bar)	Operating Temperature (ºC)
1	Inlet Naphtha 946-TK-5	8	45	3	35
2	Inlet ADO Product 946-TK-06	12	90	7	80
3	Inlet ADO Product 946-TK-07	8	90	7	80
4	Suction ADO Product 946-TK-07	12	90	7	80
5	Discharge Crude 946-P1AB to CDU	22	48	17	38
6	Inlet Kerosene Product 946-TK-20	13	90	7	80
7	Kerosene Product 946-TK-19	13	90	7	80
8	Suction Load Kerosene 946-TK-20	12	50	7	40
9	Suction Load Kerosene Prod 946-TK-19	13	90	7	80
10	Suction ADO Product 946-P-2D	6	44	1	34
11	Loading Residue Discharge Crude from Jetty	9	77	4	67

Note: ADO – Automatic diesel oil, CDU – Crude distillation oil.

Calculation Corrosion Rate

The determination of the corrosion rate used in the assessment is based on API 570 using thickness measurements from the actual condition and the previous inspection, therefore the short-term corrosion rate of an individual condition monitoring location shall be used for the internal corrosion rate from the following formula [16]:

$$\text{Corrosion Rate} = \frac{thickness\ previous - thickness\ actual}{time\ (years)\ between\ thickness\ previous\ and\ thickness\ actual} \quad (1)$$

Future Corrosion Allowance Method

The corrosion assessment based on API 579/ASME FFS-1 Part 4 thickness measurement approach. The assessment was conducted with the end-of-life target of 20 years used. Hence, the future corrosion allowance (FCA) both internal and external corrosion was utilized for the next 20 years. The future corrosion allowance given by the following formula below:

$$FCA_i = CR_i \times (2043 - \text{last inspection date}) \quad (2)$$

$$FCA_e = CR_e \times (2043 - \text{last inspection date}) \quad (3)$$

Where:
2043 = the next 20 years used from now (2023 + 20 years)
FCA_i = internal future corrosion allowance (mm)
FCA_e = external future corrosion allowance (mm)
CR_i = internal corrosion rate (mm/year)
CR_e = external corrosion rate (mm/year)

Remaining Life Assessment

The purpose remaining life assessment is to calculate the residual life for each component to continue the operation within the normal operating condition and will use the operating temperature and operating pressure. The target of life extension is 20 years from the assessment date which is in 2043. The remaining life shall be calculated given by the following formula below [17]:

$$\text{remaining life (years)} = \frac{T\ actual - T\ required}{Corrosion\ Rate} \quad (4)$$

$$T\ required = Max\ (Tmin, Tlim) \quad (5)$$

The actual thickness was measured at the time of inspection for a specified location. In this study, the actual thickness is the minimum thickness between the thickness of a straight pipe. The required thickness is the thickness computed by the design formulas at the same location as the actual thickness before adding the corrosion or mechanical allowance and manufacturer's tolerance. The minimum required thickness is the maximum thickness between the minimum required thickness as per ASME B31.3 and limiting thickness refers to API 579. The minimum required thickness refers to ASME B31.3 using basic allowable stress (S) for carbon steel materials A53 B with a minimum temperature of 20ºF, weld joint strength reduction factor (W) for carbon steel with component temperature below 800ºF, the value of coefficient (Y) of ferritic steels and temperature below 900ºF, and basic quality factors for longitudinal weld joints in pipes and tubes (E) for seamless pipe, then calculate with the sum of the mechanical allowance include the thread or groove depth and corrosion allowance [18]. The corrosion rate is the maximum internal corrosion rate between the straight pipe and elbow, then calculate with external corrosion. The result of the remaining life or estimated life (EL) for each component is shown in **TABLE 4.**

Fitness-For-Services Assessment

The following assessment procedure is to determine the thickness profile and the minimum measured thickness based on inspection historical data, then determine the wall thickness to be used (Tc) with the calculation of thickness nominal (wall thickness from manufacturer) and future corrosion allowance for each piping line. After determining the wall thickness to be used (Tc), the next assessment is computing the remaining thickness ratio (R) with the following formula given below:

$$Tc = Tnom - FCA \quad (6)$$

$$R = \frac{Tmm - FCA}{Tc} \tag{7}$$

The next assessment is computing the length for thickness averaging (L), where the parameter of Q is evaluated using Table 4.8 API 579 FFS with RSF_a = 0.90. the result of the thickness ratio and the length for thickness averaging is shown in **TABLE 8.**

$$L = Q\sqrt{DT_C} \tag{8}$$

The next step is evaluating the critical thickness profile (CTP), therefore to be conservative, take the minimum measured thickness in the longitudinal and circumferential directions where the value will be equal to the minimum measured thickness (Tmm). The next assessment is determining the acceptability for equipment to continue the operation based on Table 4.4 API 579 FFS criteria. The first parameter is average measured criteria . The critical thickness profile (CTP) will be calculated with future corrosion allowance (FCA), where assumed internal and external corrosion is expected to occur for susceptible material. Hence, the FCA was used by adding internal FCA and external FCA The result of assessment level 1 for average measured thickness is shown in **TABLE 9.** The acceptance criteria are that the thickness of the pipe and elbow shall be greater or equal to the minimum required thickness (Tmin).

The second parameter is the minimum measured thickness for piping components shall be greater or equal to the maximum value between minimum required thickness and limiting thickness with the following formula as given below:

$$(T_{mm} - FCA_{ml}) > max\ [0.5\ T_{min}, T_{lim}) \tag{9}$$

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

If the piping component does not meet the level 1 requirements, then the following assessment shall be considered such as adjusting FCA by remediation techniques, conducting level 2 with point thickness reading data and internal pressure, external pressure, and supplemental load to characterize the metal loss. In addition, conduct a level 3 assessment using stress analysis techniques.

RESULTS AND DISCUSSION

The following decision process to determine the external corrosion rate in this study is based on API 581 Table 15.2/15.2M calculation damage factor for external corrosion [19]. The result of the internal corrosion rate (pipe and elbow) and external corrosion rate shall be compared . The maximum corrosion rate will be selected to determine the future corrosion allowance and remaining life assessment.

TABLE 2. Corrosion rate

No.	Line Name	Internal Corrosion Rate (mm/year)		External Corrosion Rate (mm/year)
		Pipe	**Elbow**	**Pipe and Elbow**
1	Inlet Naphtha 946-TK-5	0.028	0.009	0.127
2	Inlet ADO Product 946-TK-06	0.018	0.037	0.025
3	Inlet ADO Product 946-TK-07	0.037	0.055	0.025
4	Suction ADO Product 946-TK-07	0.018	0.037	0.025
5	Discharge Crude 946-P1AB to CDU	0.020	0.010	0.127
6	Inlet Kerosene Product 946-TK-20	0.026	0.026	0.025
7	Kerosene Product 946-TK-19	0.026	0.009	0.025
8	Suction Load Kerosene 946-TK-20	0.009	0.018	0.127
9	Suction Load Kerosene Prod 946-TK-19	0.026	0.026	0.025
10	Suction ADO Product 946-P-2D	0.037	0.018	0.127
11	Loading Residue Discharge Crude from Jetty	0.020	0.020	0.127

Note: ADO – Automatic diesel oil, CDU – Crude distillation oil.

TABLE 3. Internal and external future corrosion allowance

No.	Line Name	FCAi	FCAe
1	Inlet Naphtha 946-TK-5	0.58	2.67
2	Inlet ADO Product 946-TK-06	0.78	0.53
3	Inlet ADO Product 946-TK-07	1.16	0.53
4	Suction ADO Product 946-TK-07	0.78	0.53
5	Discharge Crude 946-P1AB to CDU	0.42	2.67
6	Inlet Kerosene Product 946-TK-20	0.54	0.53
7	Kerosene Product 946-TK-19	0.54	0.53
8	Suction Load Kerosene 946-TK-20	0.39	2.67
9	Suction Load Kerosene Prod 946-TK-19	0.54	0.53
10	Suction ADO Product 946-P-2D	0.78	2.67
11	Loading Residue Discharge Crude from Jetty	0.42	2.67

Note: ADO – Automatic diesel oil, CDU – Crude distillation oil, FCA_i – Internal future corrosion allowance, FCA_e – External future corrosion allowance.

The screening result of remaining useful life from 11 piping systems was found the lowest value below 20 years, there were two piping process lines that have remaining life under 20 years, where the line is Inlet Naphtha 946-TK-5 with 18 years, and Discharge Crude 946-P1AB to CDU system with 14 years as shown in **TABLE 4**. The other system has an estimated life of over 20 years and it is potentially safe with given data. Determination of the remaining life assessment in the piping system is taken at the lowest value, with the lowest remaining life, there may be a risk of failure in the installation. For those components with a predicted life of fewer than 20 years, the following assessment of fitness-for-services shall be considered with identifying active damage mechanisms to evaluate general metal loss (uniform or local) that exceeds or is predicted to exceed the corrosion allowance before the next scheduled inspection. The general metal loss may occur on the inside or outside surface of the component with assessment procedures based on point thickness readings and thickness profiles provided by condition monitoring [20].

TABLE 4. Result of estimated life

No.	Line Name	T_{actual} (mm)		T_{min} (mm)	T_{lim} (mm)	EL
		Straight	Elbow			
1	Inlet Naphtha 946-TK-5	5.40	5.00	1.93	1.30	18.84
2	Inlet ADO Product 946-TK-06	5.50	5.17	2.10	1.30	48.65
3	Inlet ADO Product 946-TK-07	5.57	4.13	1.93	1.30	26.36
4	Suction ADO Product 946-TK-07	7.68	7.62	2.55	1.64	80.88
5	Discharge Crude 946-P1AB to CDU	7.20	8.04	4.94	1.64	14.40
6	Inlet Kerosene Product 946-TK-20	8.41	8.40	2.88	1.85	107.80
7	Kerosene Product 946-TK-19	7.90	5.98	2.88	1.85	60.08
8	Suction Load Kerosene 946-TK-20	6.89	9.02	3.14	2.22	24.77
9	Suction Load Kerosene Prod 946-TK-19	9.04	9.75	3.27	2.22	112.78
10	Suction ADO Product 946-P-2D	10.33	9.68	2.37	2.23	43.58
11	Loading Residue Discharge Crude from Jetty	6.38	9.30	3.25	3.02	20.27

Note: ADO – Automatic diesel oil, CDU – Crude distillation oil, T_{actual} – Thickness actual, T_{min} – Minimum required thickness, T_{lim} – Limiting thickness, EL – Estimated Life.

The damage mechanisms were reviewed by fluids properties and operating conditions for each corrosion group. The thinning type is assigned for each potential thinning mechanism with screening questions. If any process contains oil with sulfur components and the operating temperature above 204ºC, the thinning mechanism is high-temperature sulfide/naphthenic acid corrosion. If the process contains hydrogen sulfide (H_2S) and hydrogen with an operating temperature above 204ºC, the thinning mechanisms is high-temperature H_2S or H_2 corrosion. If the fluid is crude oil with the presence of sand or debris with the complexity of the branch connections on the pipe, it will susceptible to erosion and considered as an adjustment factor for thinning damage mechanism [21]. The following are the potential damage mechanisms in piping system units, as shown in **TABLE 5.**

TABLE 5. Active damage mechanisms

No.	Damage Mechanism	Active	Remarks
1	Thinning	Yes	
2	Component lining	No	No lining inside the piping system
3	External corrosion	Yes	
4	Corrosion under insulation	No	No insulated piping in this piping system
5	Piping mechanical fatigue	No	No exposed to cyclical stress from mechanical or thermal cycling for an extended period
6	External chloride stress corrosion cracking - austenitic component	No	No Stainless-Steel Material
7	External chloride stress corrosion cracking – corrosion under insulation	No	No Stainless-Steel Material
8	High temperature hydrogen attack	No	Operating temperature not reach > 350^{o}F
9	Sulfide stress cracking, hydrogen induced cracking, hydrogen sulfide	No	No H_2S partial pressure > 0.05 psi
10	Brittle fracture	No	Operating temperature not reach < -20^{o}F
11	Low alloy steel embrittlement	No	Operating temperature not reach > 1100^{o}F
12	Sigma phase embrittlement	No	No Stainless Steel material with operating temperature > 1100^{o}F
13	885^{o}F Embrittlement	No	No High Cr-Steel material with operating temperature > 700^{o}F

TABLE 6. Minimum required thickness

No.	Line Name	WT (mm)	T_{min} (mm)	Tmm Pipe (mm)
1	Inlet Naphtha 946-TK-5	6.02	1.93	5.40
5	Discharge Crude 946-P1AB to CDU	8.18	4.94	7.20

Note: WT - Wall thickness, T_{min} – Minimum required thickness, T_{mm} – Minimum measured thickness, CDU - Crude distillation oil.

TABLE 7. Length of thickness averaging

No.	Line Name	Tc (mm)	R	L (mm)
1	Inlet Naphtha 946-TK-5	2.77	0.78	27.27
5	Discharge Crude 946-P1AB to CDU	5.09	0.81	66.52

Note: Tc – Wall thickness to be used, R – Thickness ratio, L – Length of thickness averaging, CDU - Crude distillation oil.

TABLE 8. Result of average measured criteria

No.	Line Name	Tmin	Tavg
1	Inlet Naphtha 946-TK-5	1.93	2.15
5	Discharge Crude 946-P1AB to CDU	4.94	4.11

Note: T_{min} – Minimum required thickness, T_{avg} – Thickness average, CDU - Crude distillation oil.

TABLE 9. Result of minimum measured thickness

No.	Line Name	Tlim	Pipe	Elbow
1	Inlet Naphtha 946-TK-5	1.30	Accepted	Accepted
5	Discharge Crude 946-P1AB to CDU	1.64	Accepted	Accepted

Note: CDU – Crude distillation oil, T_{lim} – Limiting thickness.

In this study, the step of assessment of general metal loss is determining the minimum required thickness from the construction code as Tmin, determining the critical thickness profile minimum measured thickness tmm from inspection data, and determining corroded wall thickness by calculating the nominal thickness minus future corrosion allowance, compute the remaining thickness ratio, compute the length for thickness averaging. All those calculations will be subject to evaluate the average measured thickness criteria and minimum measured thickness [22]. The following information for minimum required thickness, minimum measured thickness, and the length of thickness averaging is shown in **TABLE 6 & 7**. The minimum required thickness (T_{min}) was calculated from ASME B31.3 using corrosion allowance. The result of the average measured criteria is shown in **TABLE 8**, where the discharge crude line of straight pipe from 946-P1AB to CDU is not accepted to meet the criteria due to the value of average measured criteria (4.11 mm) being below the minimum required thickness (4.94 mm). Continuing to level 2 assessment where the design pressure is at 0.9 RSFa will generate the minimum required thickness in 4.76 mm. However, the average measured criteria result still did not reach the value of the minimum required thickness. The result of Inlet Naphtha 946-TK-5 for evaluation average measured criteria was accepted due to the value of the pipe is greater than the minimum required thickness.

The result of the second evaluation is shown in **TABLE 9.** The minimum measured thickness for two components of the piping system was evaluated. The value of the minimum measured thickness which is already reduced by internal and external corrosion allowance is greater than the maximum value between the minimum required thickness and limiting thickness. Therefore, both of the piping systems are accepted and meet the criteria. As a result of the piping system, Inlet Naphtha 946-TK-5 meets the level 1 assessment requirements and it is accepted to continue the operation with normal inspection and monitoring. However, the piping system of the Discharge Crude line from 946-P1AB to CDU does not meet the level 1 and level 2 assessment requirements because the critical thickness point not exceeds the minimum required thickness (T_{min}). The following action can be considered as producing a level 3 assessment, or rerating, repairing, and replacing the component. All those methods of fitness for services were applied to identify whether the component can continue the operation or rerating [23].

The inspection planning refers to the possibility of damage mechanisms. It should be scheduled based on the type of failure, the rate of failure, the tolerance of the equipment to the type of failure, the likelihood of the NDT method used to identify the defect and the minimum timeframe specified for inspection and monitoring. The inspection plan and maintenance are based on the types of damage mechanisms as shown in **TABLE 10**, for external metal loss with painted or bare metal, the accessible area shall be evaluated with 100% visual inspection of external condition, including all paint breakdown and damaged areas shall be identified and photographed. The inspection plan for general thinning or internal metal loss is using ultrasonic thickness measurement scanning and profile radiography [24]. The ultrasonic thickness measurement scanning was chosen because it will provide information related thickness of the pipe which will experience thinning due to corrosion, or thickening as a corrosion product [25]. The profile radiography test was used to measure the metal loss area due to internal corrosion, erosion, and corrosion under insulation. It will provide information on the thickness profile as the result of thickness measurement [26]. The magnetic particle or dye penetrant test shall cover the welding area, cold bends, and other severe stress concentration areas. The dye penetrant test was chosen because it will cover the discontinuities at the surface of materials, and the magnetic particle test was chosen because it will detect the presence of discontinuities or cracks at the surface and sub-surface of ferromagnetic materials [27].

TABLE 10. Inspection plan activities

Line Name	Estimated Life	Damage Mechanisms	Inspection Plan
Inlet Naphtha 946-TK-5	18.84 Years	Atmospheric (External Corrosion & Thinning - Internal Corrosion	External Corrosion: 100% inspection of the external condition and all paint breakdown inaccessible areas. All damaged areas shall be identified and photographed. The extent of flaw dimensions is to be recorded from the datum and followed up by UT-scan thickness measurement. Monitor previous finding conditions, if any external coating damage should be considered recoating the external corroded area to prevent further corrosion.
Discharge Crude 946-P1AB to CDU	14.4 Years		Internal Corrosion: Monitoring previous minimum thickness. Where flaws are detected multiple, the grid readings should be taken. Any detected flaws with potential critical damage should be followed up by radiography testing or laser scan to determine damage profile.

CONCLUSION

The overall result of the piping equipment's initial screening life assessment shows two piping systems with an estimated life of is under 20 years. The other nine piping systems have an estimated life of above 20 years and will continue the operation with inspection and maintenance monitoring according to the normal schedule. However, the two piping systems components are assessed with fitness for services level 1, to evaluate the thickness point and whether the component still runs according to the operating conditions or shall be rerated. The result for Inlet Naphtha 946-TK-5 piping systems is accepted for assessment level 1, both in evaluating average measured criteria and minimum measured thickness. The piping systems can continue the operation until the estimated life. Another result for the Discharge of Crude 946-P1AB to CDU piping systems was not accepted due to the minimum measured thickness did not meet the criteria. Hence, the piping systems are potentially unsafe with the given data during the lifetime. The next assessment for Level 2 or promotion to Level 3 is recommended. If still not fit for further services, it will be repaired, replaced, or re-rated the design of operating condition.

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