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Case Study: Assessment of Internal Corrosion in a Water Containing Oil Transmission Pipeline

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Abstract

The internal corrosion of an oil transmission pipeline was evaluated in this case study. Flow regime, water accumulation locations, corrosion damage mechanism, wall loss % and pitting corrosion rate were modelled using iFILMS™ interface. Considering the predicted remaining life and corrosion rate of the pipeline, corrosion mitigation strategies were also suggested, and the need for internal corrosion inspection/monitoring was assessed.

1. Introduction

Internal corrosion is considered as the most contributor to pipelines' failure and leak[1]. The possibility of corrosion in oil transmission pipelines is highly defined by the possibility of water accumulation[2]. Transmission pipelines are generally considered as low corrosivity mediums because of their low water content (less than 0.5% by volume basic sediment and water (BS&W) as of transport quality specification). Additionally, they carry little or no CO_2 or H_2S and operate under low temperature which limits the influence of corrosive species such as sulfur[3].

In this study the internal corrosion of a sample oil transmission pipeline was evaluated, and possible corrosion monitoring and mitigation techniques was discussed.

2. Internal Corrosion Assessment

The internal corrosion of a multiphase pipeline was assessed in this study, where the sample pipeline transmits an oil-based fluid with an approximate water content of 5%.

The investigated pipeline is an oil transmission pipeline, located between an oil separator unit and storage tank. Figure 1 shows the location of the studied pipeline in the context of entire oil and gas infrastructure.

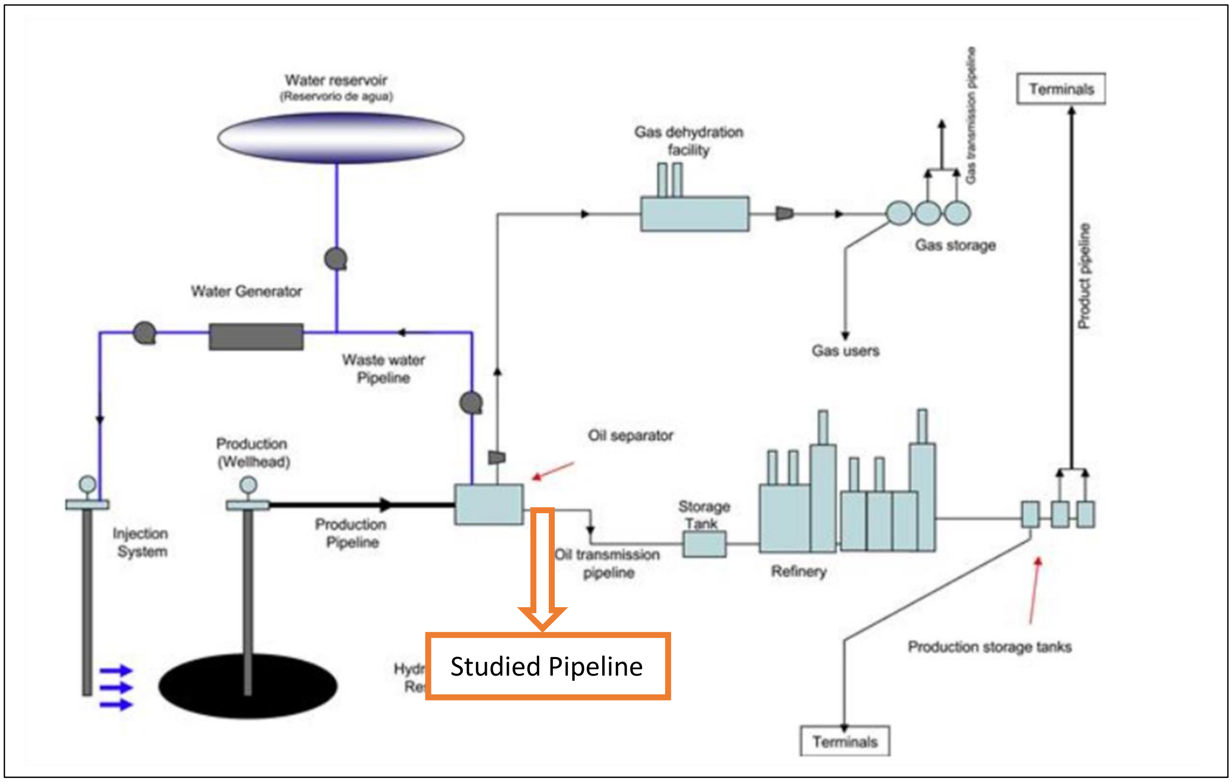

Figure 1. Location of the studied pipeline in the context of entire oil and gas infrastructure[3]

The pipeline was a 2225.9 m long carbon steel pipeline, which was receiving oil from an oil separator unit and transmitting it to a storage tank. This pipeline was constructed in January of 2010, was 219.1 mm in diameter and had a nominal wall thickness of 5.56 millimeters. Table 1 presents the operational parameters of this pipeline as recorded in January 2013. The flow direction was from the oil separator unit toward storage tank (unidirectional flow) and pipeline chainage was started from oil separator (Oil separator: Ch.0.0 m and storage tank: Ch. 2225.9 m). Figure 2 presents elevation profile of the pipeline.

Table 1. Operational parameters in the studied pipeline as recorded in January 2010

Data collection date	***Oil flow rate***	***Water flow rate***	***Gas flow rate***	***Temperature***	***Total pressure***	***pH_2S***	***pCO_2***	***Sulfur***	***Sulfate***	***Bicarbonate***	***Chloride***	***Acetic acid***	***Solid***
mm/yyyy	m^3/d	m^3/d	m^3/d	ºC	kPa	mol %	mol %	g/m^3	g/m^3	g/m^3	g/m^3	g/m^3	g/m^3
01/2013	2,098.00	104.90	-	7.13	337.65	-	-	-	-	-	-	-	-

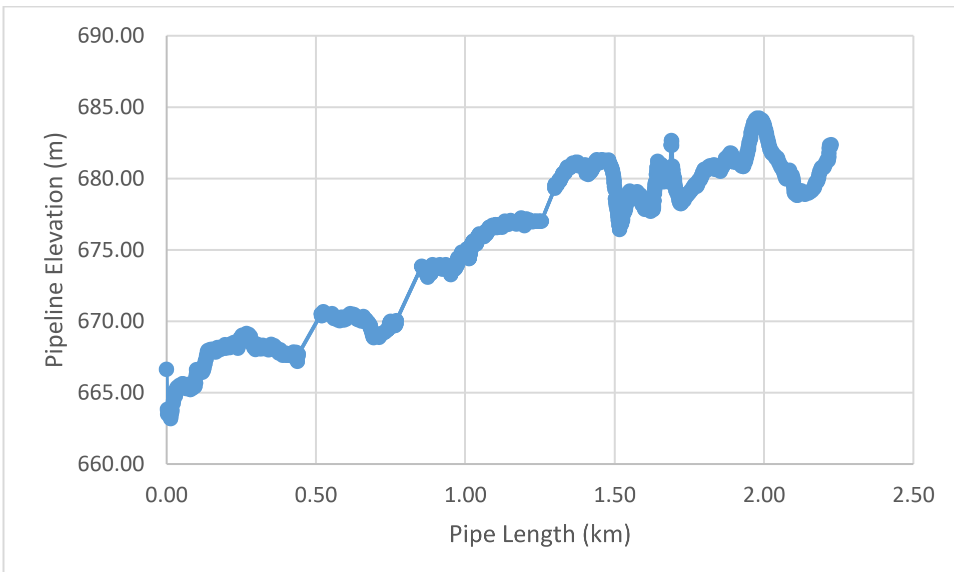

Figure 2. Pipeline elevation profile

The corrosivity of the fluids transported by transmission pipelines are generally low since the majority of water content is expected to be removed in the upstream separator in order to meet transport quality specification and satisfy the limit of 0.5% by volume basic sediment and water (BS&W)[3].

As illustrated in the Table 1, the pipeline of interest was not carrying any CO_2 or H_2S and was not considered susceptible to sour or sweet corrosion. Additionally, it was containing no corrosive species such as sulfur or chloride to influence corrosion. However, the pipeline was recorded to contain above limit water content as monitored in 2013 (about 5% by volume) that could cause corrosion as a result of possible water accumulation on the surface.

This study evaluated the profiles of temperature and pressure drop along the pipeline length. The possibility of water accumulation, possible flow regimes, possible corrosion damage mechanisms, maximum pitting corrosion rate, maximum wall loss and remaining life was also assessed. Corrosion mitigation strategies was also recommended, as well as monitoring/inspection techniques. A commercial software (iFILMS™) was utilized in this study in order to model and predict possible corrosion damage mechanisms, estimate the corrosion rate and develop possible required mitigation methods to control the rate of corrosion.

Figure 3 presents the profile of temperature and pressure drop along the length of the pipe.

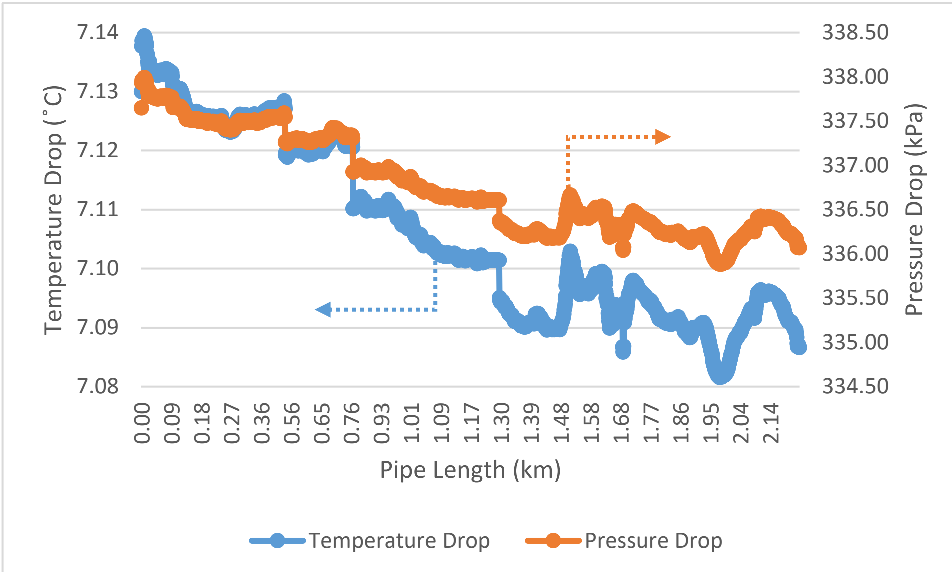

Figure 3. Temperature and pressure drop profile

Pipeline flow can significantly influence on the internal corrosion of oil transmission pipelines through affecting on pressure drop, flow regime and water accumulation. Possible active flow regimes and locations of water accumulation were modelled and presented as Figure 4 and Figure 5, respectively. The commercial modelling software (iFILMS^{TM}) didn't indicate deposition of solids along the length of the pipeline.

The modelling software predicted multiple locations of water accumulation along the pipeline and that was addressed as the susceptible locations for internal corrosion. Internal corrosion can take place at the steel-water interface, where water drops out of the oil phase and wet the steel surface. That phenomenon could be attributed to high electrical conductivity of the water phase as compared to oil phase, which stimulates the rate of corrosion at the water accumulation locations.

The modelling software considered 13 different corrosion damage mechanisms and predicted localized pitting corrosion (LPC) as an active corrosion damage mechanism, under the operational conditions (flow, temperature and pressure) and composition of the fluid. Corrosion damage location was predicted to occur at 6 o'clock circumference location (bottom of the pipe).

After modelling the possible locations of water accumulation as susceptible locations to internal corrosion and identification of corrosion damage mechanism, internal corrosion rate was predicted. Localized pitting corrosion rate and wall loss percentage were predicted along the pipeline. The rate of corrosion and wall loss % were predicted at two different dates: 06/2020 and 12/2025. Conservatively, small amount of solid (0.5×10^{-6} g/m^3) was assumed in the pipe flow for the prediction of maximum corrosion rate and wall loss % at the defined dates. Figure 6 shows the effect of solid content on corrosion rate and wall loss % at 06/2020. As is illustrated in Figure 6, a small amount of solid content increased the rate of corrosion from 0.17 mm/ year to 0.19 mm/year. Similarly, wall loss % increased from 21.45% to 23.48% as a result of solid content. For the sake of conservatism, solid content of 0.5 x 10^{-6} g/m^3 was considered in the rest of investigation.

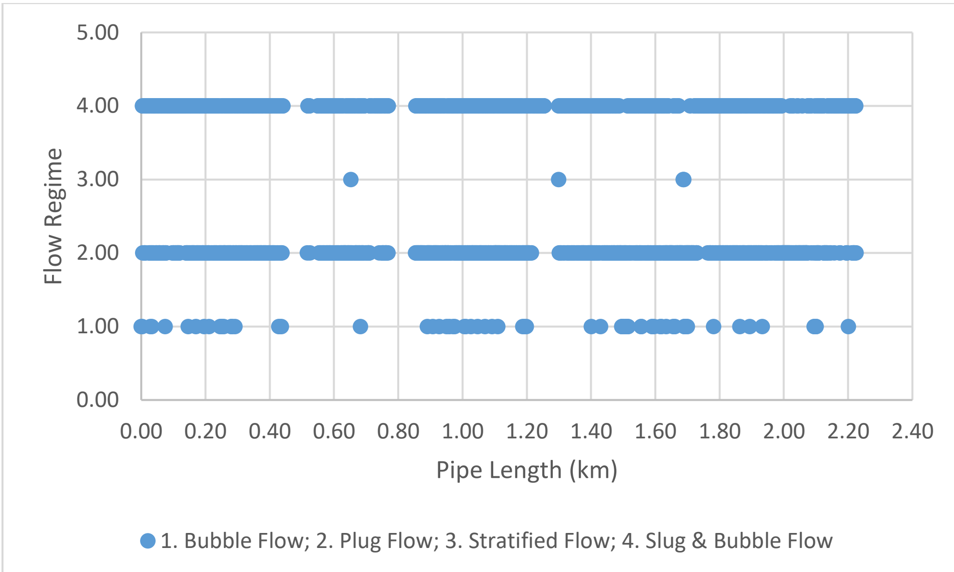

Figure 4. Active flow regimes

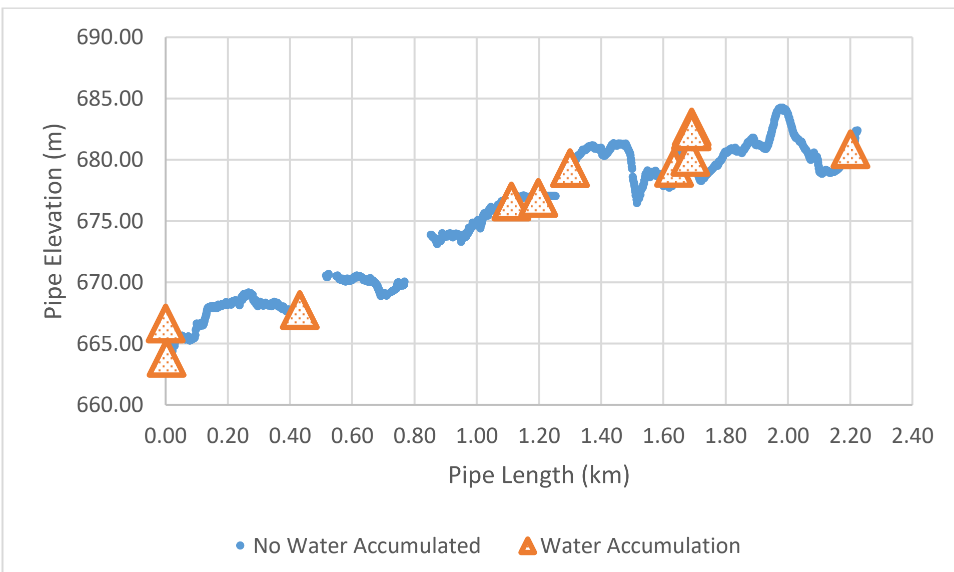

Figure 5. Locations of water accumulation

The effect of time on the properties of surface layer and its corresponding influence on the corrosion rate was evaluate through modelling of corrosion rate and wall loss % at two different combinations of time factor (TF) and time calibration factor (TCF) and is illustrated in Figure 7. (Condition 1: TF=TCF=3; Condition 2: TF=TCF= 5). Time factor is an input parameter in the modelling software that incorporate the effect of surface layer compactness and corrosion protection performance to the analysis; the higher the value of time factor, the more compact surface layer. Likewise, time calibration factor is another modelling parameter to take in the effect of surface layer characteristics on the rate of corrosion and it represents the required time (in years) for the formation of an efficient corrosion protective layer, such that after this duration no significant change is expected in the rate of corrosion.

Figure 7 shows the predicted corrosion rate and wall loss % at 06/2020 under the considered time effect conditions. In both cases autocatalytic factor (ACF) is considered as 50. autocatalytic factor (ACF) is another time-based input in the utilized modelling software which represents the duration for 50% remaining wall loss.

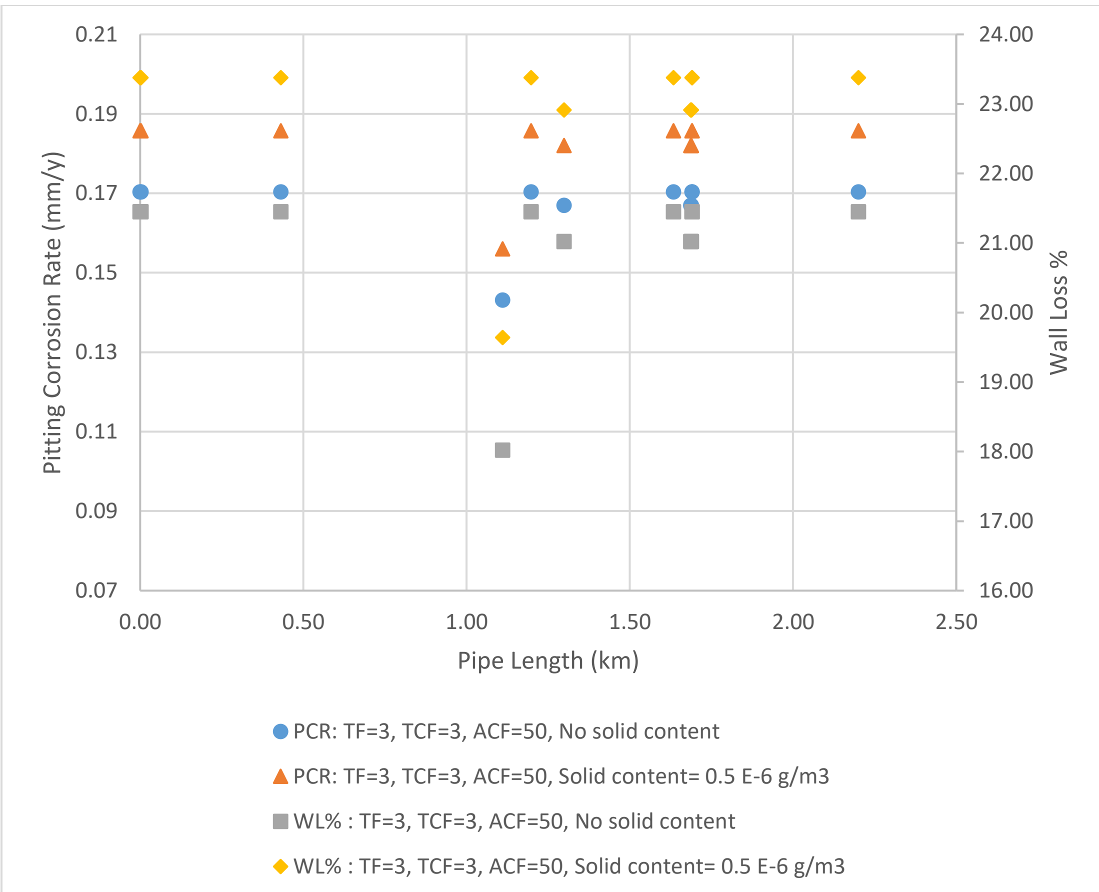

Figure 6. Effect of solid content on pitting corrosion rate and wall loss% at 06/2020

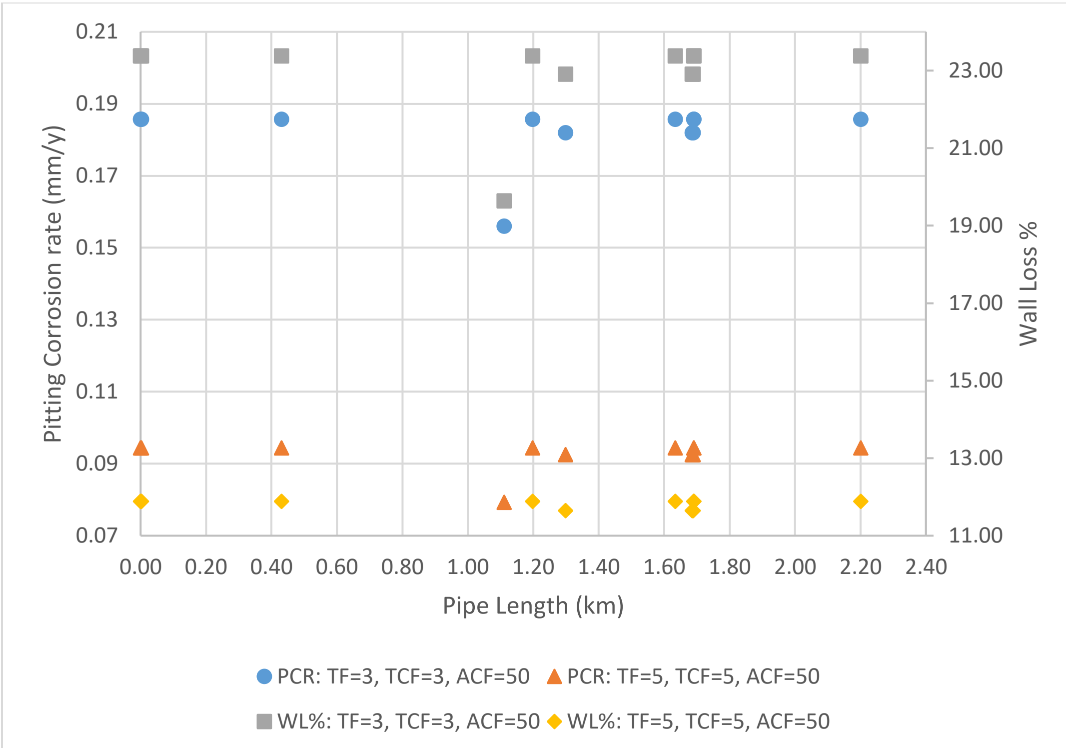

Figure 7. Effect of time on corrosion rate and wall loss% at 06/2020.

Maximum pitting corrosion rate and wall loss % were also predicted at 12/2025 (Figure 8).

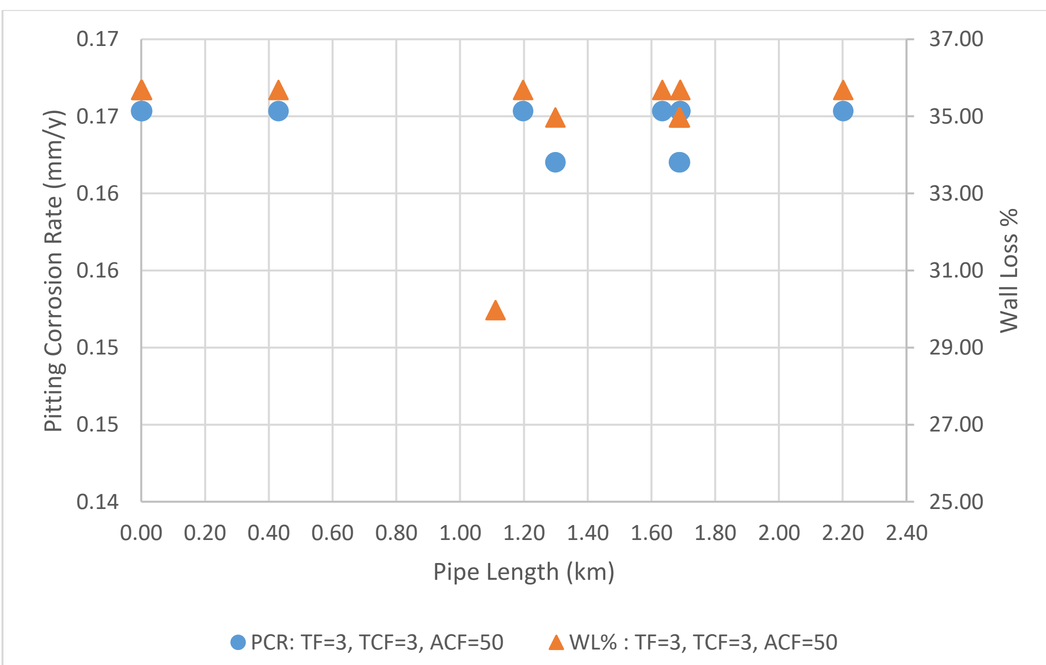

Figure 8. Pitting corrosion rate and wall loss% at 12/2025.

3. Internal Corrosion Mitigation

The model predicted the rate of corrosion on 06/2020 to be about 0.17 mm/year. This rate of corrosion was considered above the accepted level of corrosion rate that can lead to no required corrosion mitigation strategy (0.1 mm/year). Additionally, as was modelled by the software if the pipeline was predicted to reach the threshold value of 50% wall loss by 2031 (at pipeline age of 21 years old), continuing the current operating conditions with no corrosion mitigation, which was not acceptable. Hence, considering the predicted remaining life and corrosion rate of the of pipeline, corrosion mitigation approach was decided to be implemented. The effect of two common corrosion mitigation strategies (Cleaning pig (pigging) and corrosion inhibitors) on the pitting corrosion rate of the pipeline was modelled, using iFILMS^{TM}. The effect of corrosion inhibitor was evaluated considering both batch and continuous inhibitors.

Figure 9 shows the effect of different corrosion mitigation techniques on pitting corrosion rate of the considered pipeline at 06/2020. The pitting corrosion rates were modelled under the condition of TF=TCF=3 and ACF=50. Table 2 summarizes the values of maximum pitting corrosion rate under different mitigation approaches as predicted by the modelling software (iFILMS^{TM}). As is presented in Table 2, the model did not predict a noticeable effect on the rate of corrosion using continuous inhibitor and the combination of pigging and batch inhibitor predicted to be an effective mitigation technique, that could reduce the rate of corrosion by almost 77%. Considering the presented data in Table 2, the combination of pigging with the frequency of more than a year and batch inhibitor with the frequency of more than a year (highlighted in Table 2) would be recommended as an optimal mitigation technique. Mandrel pigging was recommended, as it offers an excellent performance in water condition. Steel Body (Mandrel) pigs consist of a steel body and replaceable cups, discs and/or brushes and are considered as versatile solution to many pipeline pigging problems. The ability to configure the kind and quantity of cups and discs and the possibility to incorporate other options such as brushes and gauge plates make mandrel pigs a very individualized choice for pipeline cleaning[4]. In terms of the frequency of pigging and batch inhibitor, the actual thickness of the inhibitor film on the metal should to be considered for the optimization of corrosion mitigation procedure and required mitigation frequency[5].

The pitting corrosion rates were modelled under the condition of TF=TCF=3 and ACF=50 and corrosion mitigation strategy of pigging with the frequency of more than a year and batch inhibitor with the frequency of more than a year at the dates of 06/2020 and 12/2025 (Figure 10).

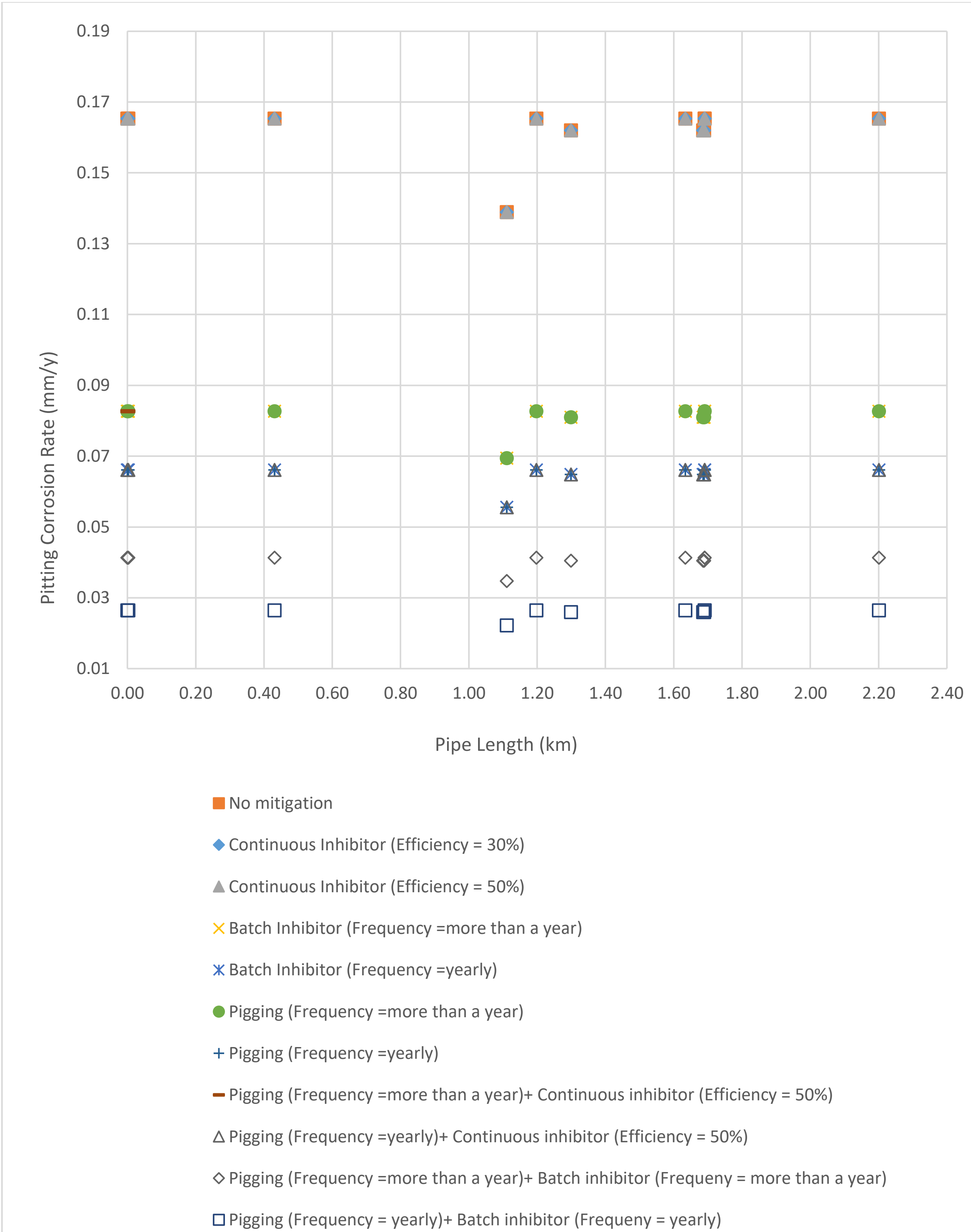

Figure 9. Effect of different internal corrosion strategies on the pitting corrosion rate at 06/2020. (TF=TCF=3, ACF=50)

Table 2. Maximum pitting corrosion rate under different internal corrosion mitigation approaches on 06/2020. (TF=TCF=3, ACF=50)

Mitigation technique	***Maximum pitting corrosion rate on 06/2020 (mm/y)***
No mitigation	0.17
Continuous inhibitor (Efficiency=30%)	0.17
Continuous inhibitor (Efficiency=50%)	0.17
Batch inhibitor (Frequency=more than a year)	0.08
Batch inhibitor (Frequency=yearly)	0.07
Pitting (Frequency=more than a year)	0.08
Pitting (Frequency=yearly)	0.07
Pitting (Frequency=more than a year) + Continuous inhibitor (Efficiency=50%)	0.08
Pitting (Frequency=yearly) + Continuous inhibitor (Efficiency=50%)	0.07
Pitting (Frequency=more than a year) + Batch inhibitor (Frequency=more than a year)	0.04
Pitting (Frequency=more than a year) + Batch inhibitor (Frequency=yearly)	0.03

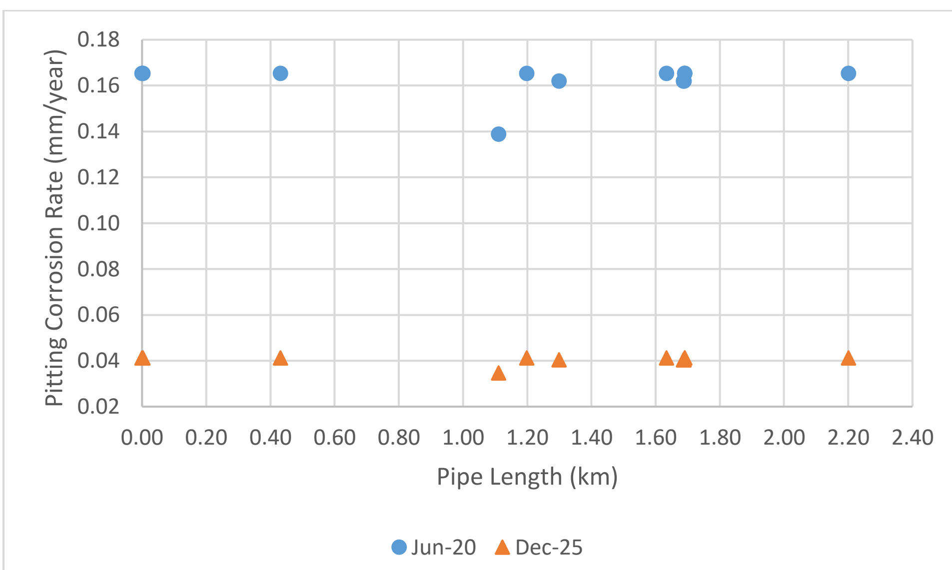

Figure 10. Pitting corrosion rate at 06/2020 and 12/2025 under corrosion mitigation strategy of pigging with the frequency of more than a year and batch inhibitor with the frequency of more than a year ((TF=TCF=3, ACF=50)

4. Internal Corrosion Monitoring/Inspection

The considered transmission pipeline was piggable and the efficiency of inline inspection (ILI) was studied as an intrusive inspection technique.

Wall loss% was modelled using iFILMS^{TM} under the corrosion mitigation condition of pigging with the frequency of more than a year and batch inhibitor with the frequency of more than a year, in order to realize the time for 50% wall loss in the pipeline as any pipeline with more than 50% of wall loss was considered as non-safe for operation. Wall loss% was modelled under the condition of TF=TCF=3 and ACF=50. The considered increase in the value of TF and TCF was meant to investigate the effect of more compact and corrosion protective surface layer on the rate of corrosion. Table 3 shows the outcome of wall loss modelling. As is presented in Table 3 the pipeline was not considered to be operational as of 06/2092 when the pipeline will be at the age of almost 82 years (highlighted in Table 3), since the wall loss % exceeds the limit of 50% by that date. The wall loss limit for safe operation depends on several parameters such as the class location of the pipeline, operating pressure, failure impact, commodity of the system, etc. This limit was considered as 50% wall loss in this case study.

Considering the efficiency of suggested mitigation strategy and calculated safe life of the pipeline, no inspection strategy was recommended at this stage. However, it would be recommended that the separating system at the upstream separating unit be frequently inspected to ensure no more water content be injected in the pipeline. Additionally, referring to the possible limitations of modelling software in the prediction of real situations, probe monitoring was also recommended to be considered for early detection of upset systems.

Table 3. Wall loss% at different dates under corrosion mitigation strategy of pigging with the frequency of more than a year and batch inhibitor with the frequency of more than a year ((TF=TCF=3, ACF=50)

Date	***Wall loss %***
12/2025	8.92
12/2035	15.07
12/2045	21.22
12/2055	27.38
12/2065	33.53
12/2075	39.68
12/2085	45.83
06/2092	50.14

5. Summary

In this study the internal corrosion of a sample water containing oil transmission pipeline was evaluated. The considered pipeline was carrying oil from a separator unit (upstream) to a storage tank (downstream). Flow regime, water accumulation, corrosion damage mechanism, wall loss %, corrosion rate and circumference location of damage were modelled using iFILMS^{TM}. Pitting corrosion rate and wall loss % were modelled for two different dates (06/2020 and 12/2025). Effect of small amount of solid content (0.5×10^{-6} g/m^3) on the maximum rate of pitting corrosion was studied. Additionally, the effect of time factors on wall loss% and maximum pitting corrosion rate was studied under two different combinations of time related factors (time factor (TF) and time calibration factor (TCF)).

Effective internal corrosion mitigation strategy was suggested after considering the combined and individual effect of batch inhibitor, continuous inhibitor and pigging on the rate of corrosion. Continuous inhibitor at the efficiencies of 30% and 50%; batch inhibitor at the frequencies of yearly and more than a year were evaluated, as well as pigging at the frequencies of yearly and more than a year. Finally, a combination of batch inhibitor at the frequency of over one year and pigging at the frequency of over one year was recommended as an internal corrosion mitigation strategy.

The need for internal corrosion monitoring/inspection was assessed through modelling the time for 50% wall loss, which found to be at the pipeline age of around 82 years, under the suggested corrosion mitigation strategy. Addressing to the acceptable age of the pipeline before reaching the wall loss limit of 50%, ILI was not recommended at this stage. However, the upstream separating unit was recommended to be frequently inspected, aiming to ensure that no additional water content be injected in the pipeline. Additionally, probe monitoring was recommended to be considered for early detection of the possible upset systems.

6. Acknowledgement

I would like to express my sincere gratitude to Dr. Sankara Papavinasam on effective and informative offering of “Internal Corrosion Control” course.

7. References

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