**CAAP Quarterly Report**

**5/21/2025**

*Project Name: Pipeline Risk Management Using Artificial Intelligence-Enabled Modeling and Decision Making*

*Contract Number: 693JK32150001CAAP*

*Prime University: Rutgers University*

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*Reporting Period: 1/1/2025 – 3/31/2025*

**Project Activities for Reporting Period:**

*Task 1 Literature Review (Completed)*

*Task 2 Data Collection from Industry Partners (Completed)*

*Task 3 Data-Driven Probabilistic Modeling of Pipeline Defects (Completed)*

*Task 4 Quantification of Probability of Failure (Completed)*

*Task 5 Decision Making of Inspection and Repair Strategy using Reinforcement Learning*

***Decision Making with AI techniques***

The reinforcement learning model is refined to optimize inspection and repair strategies for whole pipeline with multiple soil zones to have the minimum life-cycle cost while satisfying the safety threshold. The model outputs are the specific pipe segments to be inspected and repaired at the specific year determined by the reinspection schedule. The growth of external corrosion defects is predicted by the Bayesian Neural Network (BNN) considering variation of soil properties at each zone along the pipeline. The ILI data and soil properties from the Mexico pipeline are used in the analysis. The transmission pipeline is made of grade X52 steel with an outside diameter of 457.2 mm and wall thickness is 6.4 mm. The total pipeline length is 112 km consisted of 559 zones and each zone has different soil properties.

***Refinement of BNN Model***

The BNN model used in this study is a purely data-driven approach. While BNN is effective in learning complex patterns and providing uncertainty information, their performance depends heavily on the amount and quality of training data. In this case, only two inspection records (2005 and 2010) were available. Due to the limitation in the input data, the BNN predictions showed fluctuations and struggle to accurately predict corrosion before the first inspection year.

To overcome these limitations, a power-law model is introduced as a post-processing step to fit the BNN-predicted corrosion data. Pipeline corrosion typically follows a nonlinear growth pattern, with the corrosion rate gradually slowing over time. This characteristic matches the mathematical behavior of power-law functions, which are suitable for modeling such nonlinear growth. By applying power-law fitting, the predicted corrosion curve becomes smoother and better aligned with corrosion growth pattern.

To address the challenges of prediction variability, data sparsity, and limited extrapolation capability, the power-law model was used to fit the BNN results. The formulation of the adopted power-law model can be seen below.



where, *y*(*t*) represents the corrosion depth or length at year *t*; *a* is the fitted parameter that scales the corrosion magnitude; *t*0 is the initiation time of corrosion in each zone; *b* is the fitted exponent parameter between 0 and 1 that characterizes the decelerating nature of corrosion growth over time.

***Life-Cycle Cost***

The cost function considers inspection cost, repair cost and failure cost, as expressed in the equation below. Assuming each zone can be inspected independently, maintenance and inspection occur simultaneously. The repair cost includes expenses for composite wrap and pipe replacement, which are incurred when the corresponding maintenance actions are implemented. The failure cost accounts for the consequences of leakage and rupture failures in each year.



where, *nin* is the inspection times; *Cin* is the inspection cost for one zone; *tini* is the year when *ith* inspection for the corresponding zone occurs; *ns* is the number of times the composite wrap is used; *Cs* is the composite wrap cost; *r* is the annual discount rate, which is 0.03 in this case; *tsi* is the year when *ith* composite wrap repair occurs; *nr* is the number of times the replacement is used; *Cr* is the replacement cost; *trj* is the year when *jth* replacement occurs; Δ*Plk*is the incremental leakage failure probability in year *i*; *Cl* is the leakage failure cost; Δ*Pbk*is the is the incremental rupture failure probability in year *j*; *Cb* is the rupture failure cost.

The summary of different types of costs used can be seen in Table 1, which are estimated based on the literature and PHMSA incidents database. Please note that the cost for rupture failure refers to the median value of property damage cost (the total cost of public and non-operator private property damage, operator’s property damage and repairs, and lost commodities) obtained in PHMSA incident database for gas transmission gathering systems, not including civil penalty by violation of federal pipeline safety regulations, emergency response, environmental remediation, fatalities, and injuries.

Table 1 Summary of different types of costs

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Inspection cost | Composite wrap | Replacement | Small leakage failure | Rupture failure |
| $4,100 | $6,510 | $35,251 | $3,963 | $396,261 |

The maintenance optimization in this study is based on a set of predefined assumptions regarding the effects of repair actions, operational constraints, and the analysis period. Specifically, once a replacement action is performed on a pipeline zone, the corrosion condition of that zone is reset to be zero, and the subsequent corrosion progression follows the same trajectory as that of a newly installed pipeline. The repair efficiency of composite wrap is assumed to be 90%. In this way, the accumulated corrosion depth in each year after repair is calculated as the existing depth plus 10% of the additional depth that would have occurred without repair. To reflect practical constraints, the same corrosion defect is allowed to receive at most one composite wrap repair over the entire lifecycle. If a zone has already undergone a composite wrap repair, future maintenance actions must be replacement. The maintenance planning horizon spans from 2010 to 2050, covering a 40-year period.

The RL optimization model aims to minimize the total life-cycle cost, which includes discounted inspection cost, composite wrap cost, replacement cost, and failure-related costs. The constraint is the probability of failure in any zone throughout the lifecycle cannot exceed 0.0001. Maintenance actions are restricted to inspection years only. The entire pipeline is divided into 559 zones at 200-meter intervals based on the soil survey. However, inspection data from 2005 and 2010 indicate that only 390 zones have corrosion defects. Therefore, maintenance planning is conducted for these 390 zones.

***Preliminary Results***

The optimized maintenance matrix for multi-zones using RL is presented in Figure 1. In the figure, blue cells represent zones where no maintenance is needed, orange cells indicate the application of composite wrap repairs, and green cells correspond to replacement repairs. It is evident that the majority of the pipeline remains in acceptable condition, as shown by the predominance of blue areas. Maintenance activities, particularly composite wrap repairs, are more frequently concentrated between 2020 and 2035, suggesting that corrosion becomes more critical in this period. Interestingly, there are no zones needed to be replaced according to this figure, indicating that the composite wrap repair is enough in this scenario. The Zone\_ID axis shows maintenance actions distributed irregularly across the pipeline, with no clear clustering pattern, implying that corrosion-prone areas are scattered rather than localized. In total, the planned maintenance interventions for all affected zones are estimated to cost $2,166,986.



Figure 1 Maintenance matrix for different zones in the pipeline.

It is important to note that the maintenance matrix shown in Figure 1 is generated based on a specific set of assumptions. Therefore, sensitivity analysis is conducted by changing threshold for probability of failure, inspection and repair costs, effectiveness of composite repair. Throughout all analysis scenarios, the strategy for inspection and repair remains the same although the life cycle cost changes. This suggests that the inspection and repair are needed as it is getting close to the threshold for probability of failure. The effect of failure cost is negligible as compared to other costs due to the small value of failure probability, which is caused by the low operating pressure as compared to high burst pressure.

Operating pressure is found being a critical parameter affecting pipeline integrity, as higher pressure increases the risk of failure, particularly in corroded segments. Figure 2 presents the impact of changing the ratio of operating pressure to yield stress on total life-cycle cost and its individual components. The results show that total life-cycle cost increases significantly with rising operating pressure. This increase is primarily driven by the increase in failure cost and composite wrap cost. As the pressure increases, the risk of rupture in corroded zones becomes more severe, leading to higher expected failure costs. Similarly, composite wrap cost increases from $1,051,165 to $1,916,165, indicating that the model compensates for the higher risk by performing earlier interventions.

Inspection costs also rise gradually, particularly beyond 8.52 MPa, suggesting that the model recommends more frequent inspections to manage increasing risk. Interestingly, replacement cost remains zero at lower pressure levels but becomes non-negligible at high operating pressure. This indicates that at very high pressure, the RL model starts incorporating replacement actions where wrap repairs are no longer sufficient to ensure reliability.

Figure 2 Impact of operating pressure on life-cycle cost.

Figure 3 illustrates the differences in the optimized maintenance schedule as the pipeline operating pressure increases from 5.52 MPa to 10.52 MPa. The results show that higher pressure leads to earlier and more frequent maintenance. At 5.52 MPa, maintenance actions are relatively sparse and distributed later in the service life, with fewer interventions occurring before 2030 in many zones. As the pressure increases to 8.52 MPa and 9.52 MPa, the frequency and density of maintenance actions increase significantly, with many zones requiring interventions as early as 2020. At the highest pressure of 10.52 MPa, maintenance becomes most intensive, with many early repairs observed in the majority of the pipeline zones as early as 2015.

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(a)

A blue and orange graph

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(b)

A graph with orange dots

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(c)

A graph with orange and blue squares

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(d)

Figure 3 Maintenance matrix at different operating pressure (a) 5.52 MPa, (b) 8.52 MPa, (c) 9.52 MPa, (d) 10.52 MPa.

This shift in scheduling is driven by the fact that higher operating pressures accelerate the risk of pipeline failure. As internal operating pressure increases, the allowable corrosion level decreases, reducing the safety margin. Therefore, the RL-based model adjusts the schedule to perform earlier inspections and repairs to prevent critical failures. It demonstrates a strong sensitivity of maintenance strategy to operating pressure. Higher pressures not only increase failure risk but also increase preventive costs through more frequent inspections and repairs.

***LCCA with Analytical Solution Methods***

Different from AI-based optimization, LCCA was conducted using analytical solution methods. Life-cycle cost management of pipelines with multiple segments was studied and efforts were made on reducing computational effort. The current framework to consider multiple segments is extended based on an analytical solution for the life-cycle cost of pipelines with a single segment developed in the previous PHMSA project (Kere and Huang 2024). In particular, the possibility of different numbers of failures in different segments are considered. For instance, in the proposed framework, when considering the expected cost associated with a single failure, the failure event can occur in either segment; when considering the expected cost associated with two failures, failures may occur within the same segment or in any two segments in a pipeline system.

The following case study focuses on a pipeline system with two segments, assuming one corrosion defect in each segment. The probability of failure for each segment is defined as the likelihood of burst failure (which includes leak and rupture), which occurs when the pipeline's burst capacity at time t, Cb,s(t), falls below the operational pressure demand, Pop, which can be expressed as:

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| --- |
|  |
|  |

Where, *χ* = model error, *dw* = pipe thickness, *σu* = pipe ultimate strength, *d*(*t*) and *l*(*t*) = corrosion depth and length at time *t*, respectively, and *D* = pipe diameter. For simplicity, corrosion defects are assumed to grow linearly over time in both depth *d*(*t*) and length *l*(*t*) as follows:

|  |  |
| --- | --- |
|  |  |
|  |  |

Where, *d*0 and *l*0 = initial corrosion depth and length, respectively; and *a* and *b* = corrosion growth rate for defect depth and length, respectively.

Examples of model parameters are listed in Table 2 including defect growth rates and pipeline material and geometric properties. Note that the two defects assumed here have different initial corrosion depth and length.

Table 2 Statistical parameters of random variables used in the case study

|  |  |  |  |
| --- | --- | --- | --- |
| Random variable | Distribution | Mean | C.O.V. (%) |
| Outside diameter of pipe, *D* (*mm*) | Deterministic | 1,016 | - |
| Nominal wall thickness, *dw* (*mm*) | Normal | 14.06 | 1.5 |
| Yield strength, *σy* (MPa) | Normal | 485 | 3 |
| Ultimate strength, *σu* (MPa) | Normal | 570 | 3 |
| Burst pressure model error, *χ* | Log-normal | 0.97 | 11.1 |
| Operating pressure, *Pop* (MPa) | Gumbel | 10.0 | 7 |
| Initial defect depth, *d*0(*mm*), for the 1st defect | Weibull | 1.15 | 72 |
| Initial defect length, *l*0 (*mm*), for the 1st defect | Log-normal | 35.68 | 82.1 |
| Initial defect depth, *d*0(*mm*), for the 2nd defect | Weibull | 2.31 | 72 |
| Initial defect length, *l*0 (*mm*), for the 2nd defect | Log-normal | 37.7 | 82.1 |
| Defect depth growth rate, *a* (*mm*/year) | Weibull | 0.576 | 70.3 |
| Defect length growth rate, *b* (*mm*/year) | Log-normal | 3.0 | 50 |

Figure 4 presents the failure probability of the two segments over time without considering any repair actions, which is determined through reliability analysis. When repair actions are taken, fragility curve will be adjusted to reflect the chosen repair impact. In this case study, it is assumed that the repair only occurs right after an inspection and is performed based on two criteria: (1) a corrosion defect depth, *d*, exceeds a certain percentage (*α*) of wall thickness, *dw*, (i.e., *dr* > *α*·*dw*); or (2) the pipe capacity with defect, *Cb*, falls below the allowable limit, which can be defined as a certain percentage (*β*) of max allowable pressure, *Pmax*, (i.e., *Cb* < *β*·*Pmax*). In particular, *β* = 139% are used in this case study following [1]. Additionally, if a burst failure occurs, a replacement will be put in place at the affected section and the pipeline is reset to be the initial state.

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| --- | --- |
| A graph with a blue line  AI-generated content may be incorrect. | A graph with a blue line  AI-generated content may be incorrect. |
| (a) | (b) |
| Figure 4. Fragility curve of a) first segment, and b) second segment | |

Table 3 presents the probability of failure occurrences during the service life: no failure (*Pf*,0), 1 failure (*Pf*,1), 2 failures (*Pf*,2), and more than 2 failures (**), for various repair levels (i.e., *dr/dw*) when 6 year inspection interval is considered. In case of only 1 failure during service, the failure can only happen in either segments; in case of 2 failures, the failures can occur either in each segment or 1 failure in each segment during the service life. As shown in Table 2, the probability of no failure during the service life (*Pf*,0) decreases as the repair threshold increases, while the probabilities of one (*Pf*,1) and two failures (*Pf*,2) occurrence increase. This is expected, as the higher value of repair threshold indicates less possibility of repair. Additionally, with a higher repair threshold, the occurrence of a second failure becomes more likely, highlighting its importance of considering more than 1 failure event in the life-cycle cost (LCC) calculations.

Table 3 Failure probabilities for various repair thresholds with Δt = 6 years

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| --- | --- | --- | --- | --- | --- | --- | --- |
| *dr/dw* | 0.2 | 0.3 | 0.4 | 0.5 | 0.6 | 0.7 | 0.8 |
| *Pf*,0 | 0.70 | 0.60 | 0.533 | 0.474 | 0.429 | 0.394 | 0.369 |
| *Pf*,1 | 0.251 | 0.310 | 0.348 | 0.371 | 0.386 | 0.394 | 0.399 |
| *Pf*,2 | 0.043 | 0.073 | 0.102 | 0.127 | 0.149 | 0.167 | 0.180 |
|  | 0.006 | 0.017 | 0.017 | 0.028 | 0.036 | 0.045 | 0.052 |

Figure 5 exemplifies the cost associated with no failures during service life which consist of inspection (shown in dashed-dotted line) and repair cost (shown in dotted line) for a 6-year inspection interval and an 80% repair threshold (α = 80%). As shown in Figure 5, both cost increases occur at inspection times due to inspection and possible repair actions, leading to cumulative costs over service life.

Figure 6 illustrates the LCC of the pipeline system as a function of the repair threshold (dr/dw) considering a 6-year inspection interval. The cost is represented by the ratio of initial construction cost (*C0*). In this plot, the solid black line represents the total expected cost (E[*CT*]), while the black dashed line indicates the total cost when no failures occur during the service life, accounting only for inspection and repair costs (E[*CT,0*]), The dotted and dash-dotted blue lines represent the total expected cost when one and two (E[*CT,1*], E[*CT,2*]) failures occur during the service life, respectively. As shown in Figure 6, the LCC of the pipeline is minimized for repair thresholds between 0.3 to 0.5. As expected, the contributions of E[*CT,1*] and E[*CT,2*] increase, while E[*CT,0*] decreases as the repair threshold increases. While E[*CT,2*] is the smallest component compared to the other two components, its contribution is not ignorable. Future evaluations will consider the inclusion of additional pipeline segments with varying inspection intervals, which will be addressed in the next report. Please note that the expected cost is obtained by multiplying probability of the failure event with consequence cost (property damage cost), and the low cost is due to the low value of probability of failure.

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| Figure 5 Cost of having no failure during service life for Δ*t* = 6, and *α* = 80% | Figure 6 life-cycle cost of pipeline system with 6-year inspection period |

***Reference***

*Kere KJ, Huang Q. An analytical approach to evaluate life-cycle cost of deteriorating pipelines. Reliability Engineering & System Safety. 2024:110287.*

**Financial Activities with Cost Share:**

The graduate student salary, fringe, and university overhead are charged for two students at Rutgers University and one student at Marquee University.

Cost share is provided by Rutgers University and Marquette University during this quarterly period as budgeted in the proposal. The cost share requirement has been met by 9/30/2024.

**Project Activities with External Partners:**

N/A

**Potential Project Risks:**

N/A

**Future Project Work:**

Work will be continued on Task 5 on decision making of inspection timing and repair strategy and Task 6 on draft final report.

**Potential Impacts to Pipeline Safety:**

The AI-enabled modeling and analysis of pipeline inspection data will be used to develop probabilistic growth models of corrosion defects and make cost-effective repair or replacement decisions to minimize pipeline failure risk.