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Proposed Statistical Model for Corrosion Failure Prediction and Lifetime Extension of Pipelines

Jessica Y. Ripple
jyr2@zips.uakron.edu

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PROPOSED STATISTICAL MODEL FOR CORROSION FAILURE PREDICTION AND LIFETIME EXTENSION OF PIPELINES

Jessica Ripple
April 21, 2015

The University of Akron
Honors College Research Project
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Executive Summary

Corrosion is an unavoidable global issue that has serious safety and environmental consequences if left unmitigated. Currently, the majority of methods used to address corrosion are reactive in nature, meaning that industries are responding to leaks, spills, and catastrophes after they have already occurred. Ideally, the asset owners of the corroding infrastructure and equipment should use predictive modeling to take proactive measures before a corrosion induced risk becomes a danger to society.

This project focuses primarily on internal pipeline corrosion. The US has hundreds of thousands of miles worth of pipelines currently in operation. These pipelines are often transporting hazardous materials, such as natural gas and crude oil. To protect society and the environment from loss of containment, the US Department of Transportation requires most pipelines to be analyzed for internal corrosion every five years using an in-line inspection (ILI) tool.

The intended audience for this model are pipeline asset owners and operators. The goal of this project was to develop a “user-friendly” model that allows a user to analyze the data collected from the ILI tool. The user can choose to accept the default analysis options or easily make adjustments to tailor the results to their data.

This report presents the results from developing a predictive model that estimates the probability of failure of a pipeline. The model utilizes data collected with an in-line inspection tool to generate a Monte Carlo simulation based on a desired statistical distribution. The results of the Monte Carlo simulation provide the user with the probability of failure that each anomaly on the pipeline presents over a specific time period. Using these probabilities, the model conducts an economic analysis to recommend an optimal repair schedule.

Going forward, this model can be improved by adding new distributions, which will allow the data to be categorized more accurately and new predictive equations, which permits the user to adjust how conservative the results should be. Also, the model would greatly benefit from a second set of ILI data of the same pipeline to validate the calculated results.
Introduction

The target audience for this research project is oil and gas pipeline operators, owners, or other responsible parties. The final product, a computer model, utilizes raw industry data, accepted industry standards, statistical analysis, and economical evaluations to recommend optimal mitigation methods and scheduling. As with any model, the results are only as accurate as the data and engineering judgement that is input.

Figure 1 shows the main process steps the model utilizes. The raw data comes from in-line inspection (ILI) tools, also known as “smart pigs”, and consists of wall thickness and anomaly width and depth. An anomaly is considered to be any defect in the pipe internal surface. Smart pigs have the ability to catalog hundreds of kilometers worth of pipeline data. Within the model, this data is then fit to an appropriate distribution curve, which can be chosen based on minimizing standard error. The next step entails performing a Monte Carlo simulation to generate probabilistic pipeline conditions. These conditions are individually assessed which provides a wide range of operating pressure estimates. Once the pipeline operation has been simulated over a specified range of time, an economic analysis can be performed which will make recommendations based on specified costs of failure and repair. The final output of the model includes a recommended year of repair at each specific anomaly location and the economic value of risk avoided by performing said repair.

Every step is completed independently and requires various amounts of user inputs. The overarching idea for this model is to allow the user to be a detailed or simplistic as he or she prefers. The model has default settings for the steps but has the flexibility for tailoring at any point.

Figure 1. Pipeline reliability model execution steps.
Currently, the main limitations of the model include the inability to distinguish between internal corrosion and erosion as well as the inability to evaluate external corrosion. Also, the model does not differentiate a failure as either a leak or a rupture. Lastly, the model assumes a constant corrosion rate with time. It cannot predict a sudden acceleration in corrosion. However, frequent and thorough data collection should be able to give an indication of a step change in the corrosion rate.

The data presented in this report is not meant to be extrapolated to represent other pipelines. The purpose of displaying and analyzing the data in this report is to showcase the types of analyses that the model can perform.
Background

General Corrosion

Corrosion is simply defined as the “degradation of a material due to a reaction with its environment” (1). A wide variety of materials can fall victim to corrosion, including metals, polymers, and ceramics. Additionally, these materials can undergo various forms of corrosion, most often simultaneously (2). Figure 2 displays the corrosion mechanism using a basic electrochemical cell schematic (2). Corrosion occurs due to the oxidation reaction taking place at the anode. The loss of electrons at the anode is balanced by the reduction reaction occurring at the cathode. Depending on the chemical concentration and properties of the environment (shown as the electrolyte in Figure 2), the corrosion rate may be almost negligible (less than 1 mpy) or very severe (greater than 200 mpy) (3).

Figure 2. Corrosion representation using electrochemical cell.

Unmitigated corrosion has significant safety, environmental, and economic consequences on a global scale. In 2002, a comprehensive study determined the total direct costs of corrosion in a wide variety of industry sectors in the United States totaled $276 billion (4). To combat corrosion, several mitigation strategies are available. The most common include material selection, coatings, inhibitors, and cathodic protection (5).

Oil Pipeline Corrosion

For this specific project, the primary focus was of internal corrosion of oil pipelines in the United States. Crude oil itself is not corrosive. Instead, the corrosion is caused by carbon dioxide (CO₂), hydrogen sulfide (H₂S), and especially water (6). At high velocities, the water will remain entrained in the crude oil and will not be able to settle out and cause corrosion (7). However, at lower velocities, there is a greater risk of two phase flow and thus corrosion can occur in the water phase. Light crude oils containing water are at a higher risk due to the greater difference in
density to water (7). Therefore, as refineries are forced to run heavier crudes over time, the crude oil pipelines will actually decrease their risk of corrosion.

Today, there are limits in place on water concentration in transporting crude oil in pipelines. In 2012, the length of U.S. oil pipelines was approximately 152,000 miles (8). For about 90% of hazardous liquid pipelines, pipeline operators have the option of using a “smart pig” to collect integrity data (9). Figure 3 illustrates a smart pig created by Nord Stream which uses magnetic flux technology, which is one of the most common methods (10). These devices are capable of detecting the location of pipeline defects such as wall thinning, mechanical damage, material defects, and cracks (9). The data, often referred to as “in-line inspection” or ILI data, was the primary input to the developed model. The United States Department of Transportation requires pipeline owners to complete a smart pig run every five years, although it is common for them to be performed even more frequently (11).

![Figure 3. Nord Stream magnetic flux smart pig.](image)

**Corrosion Models**

Currently in industry, it is common to use one of the previously developed deterministic models to estimate the service lifetime before corrosion induced pipeline failure. Figure 4 compares the pipeline failure pressure as a function of defect length using different models (12). The models all require similar information (anomaly length and depth, pipe thickness, etc.) to calculate the failure pressure. For the purpose of this model, the Modified B31G was used since it is a standard produced by the American Society of Mechanical Engineers (ASME) and is less conservative than the original B31G model (13). The ASME Modified B31G method was primarily developed on older, lower strength steels while some of the “newer” models, including the DNV-99 method, were developed based on modern pipeline materials (14).
A Level 1 Modified B31G evaluation was conducted, based on the steps outlined in the ASME Technical Standard document (13). Equation 1 shows the formula used to calculate the failure pressure for the model, where $Y_S$ is yield strength, $t$ is the pipe thickness, $d(T)$ is the anomaly depth at time $T$, $L(T)$ is the anomaly length at time $T$, and $D$ is pipe diameter (12). This equation assumes a “flow stress” expression appropriate for a material with specified minimum yield strengths below 483 MPa and operating temperatures below 120°C (13).

Equation 1: $$ P_f = \frac{2(Y_S + 68.95 \text{ MPa})t}{D} \left(1 - 0.85 \frac{d(T)}{\ell} \right) \left(1 - 0.85 \frac{d(T)}{M^2} \right), \quad M = \sqrt{1 + 0.6275 \frac{L(T)^2}{\ell t} - 0.003375 \frac{L(T)^4}{D^2 \ell^2}} $$
Model Discussion

Data Input

The ILI data used to develop this model spanned 100 kilometers of industrial pipeline. The source of this pipeline data cannot be identified due to confidentiality, although it was provided to the University of Akron with the intention of creating a predictive model. It is worth noting that only the raw data points were provided. Any subsequent analyses, statistical modeling, or calculations were completed as part of this research project.

Within the 100 kilometers of data, over 3,400 anomalies were documented. Figure 5 displays the frequency of the data utilized in the model. This analysis was carried out Potential outliers were not removed because these sites likely represent spots of local accelerated corrosion which was considered important to keep in the model. Corrosion rates were determined based on the assumption that the pipe had been corroding for 10 years. Ideally, data from two separate ILI audits would be used to estimate corrosion rates more accurately.

Figure 5. Pipeline ILI data histograms from a private industrial source.

Figure 6 shows the probability density function (PDF) curves that were necessary for running the model. The corrosion rate is shown on the left while the longitudinal growth rate is shown on the right. These distribution curves are required for performing the Monte Carlo simulation. Figure 7 shows an example of how the distribution curves were chosen for the longitudinal growth rate. The fit that yielded the lowest standard error was selected to represent the data shape. Therefore, the corrosion rate was fit to a normal distribution curve while the longitudinal growth rate was fit to a lognormal distribution curve.
Monte Carlo Simulation

Once the raw data is entered and the appropriate distribution curve parameters are evaluated, the probability of failure over time for each anomaly location is calculated via the Monte Carlo simulation (MCS) process. The Monte Carlo simulation is defined as “a numerical...
experimentation technique to obtain the statistics of the output variables of a system computation model, given the statistics of the input variables” (15). Figure 8 outlines the individual steps required to complete a MCS. A random number generator was used in Step 1. This random number was associated with a corrosion and anomaly longitudinal growth rate using the inverse normal and lognormal functions, respectively. A MCS simulation including 1000 trials was performed for each specific anomaly location. Therefore, the rate of corrosion depth and longitudinal growth were statistical inputs to the simulation while the anomaly length and depth were not. For each anomaly, the cumulative distribution function (CDF) of the calculated failure pressure was plotted. The CDF is defined by NIST as the “probability that the variable takes a value less than or equal to x” (16). For this model, the “variable” is the pressure calculated using Equation 1 and “x” is the pipeline operating pressure. Therefore, the failure probability is found by plotting the CDF and finding the probability that corresponds to the pipeline operating pressure, as shown in Figure 10. The model was set up on the basis for 15 years prediction.

**Figure 8.** Calculation steps of a MCS process.
Figure 9 shows CDF equations for distributions that are commonly seen in corrosion data (17), (18), (19), (20). When a random number is selected in Step 1 of the MCS process, it represents a probability, labeled p. The desired variable (whether it be corrosion rate, anomaly length, etc.) is then calculated by solving for the x value that corresponds to a specific value of p. Inverse distribution equations are commonly available in software, including Microsoft Excel and MATLAB. The inverse distribution equations require the parameters (such as the average and standard deviation) that are shown below.

<table>
<thead>
<tr>
<th>Distribution</th>
<th>Equation</th>
<th>Parameters</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal</td>
<td>$\mathcal{N} \left( \mu, \sigma \right)$</td>
<td>$\mu$: average, $\sigma$: standard deviation</td>
</tr>
<tr>
<td>Lognormal</td>
<td>$\text{Lognormal} \left( \mu, \sigma \right)$</td>
<td>$\mu$: average, $\sigma$: standard deviation</td>
</tr>
<tr>
<td>Weibull</td>
<td>$\text{Weibull} \left( \alpha, \beta \right)$</td>
<td>$\alpha$: scale parameter, $\beta$: shape parameter</td>
</tr>
</tbody>
</table>

Figure 9. Commonly used distributions and their respective cumulative distribution functions.

Figure 10 shows the MCS output for a singular anomaly after 15 years of predicted corrosion. The operating pressure of the line is 5.6 MPa, which intersects the CDF curve at approximately 71%. From this data, the conclusion is that after 15 years, the probability of this particular anomaly corroding to the point of failure is 71%.
To draw conclusions about the anomaly over time, the average calculated pressure was used. **Figure 11** shows the range of pressures calculated and the overall probability of failure per year for the same anomaly considered in **Figure 10**. The data bars correspond to the maximum and minimum pressures that were calculated in the MCS. At year 4, the minimum calculated pressure begins to extend below the pipeline operating pressure. This results in some amount of failure probability, as shown in the graph on the right.
Lastly, Figure 12 illustrates how the individual anomaly analyses were combined to produce a failure probability “snapshot” of the bulk pipeline after 15 years of predicted corrosion. The percentages represent the probability of failure at each specific location. While this image was created manually using MATLAB, the intention is to have the simulation generate all images automatically.

Figure 12. Failure probability of pipeline segment after 15 years.

Economic Analysis

There are many ways of accounting for costs associated with corrosion and how to account for these savings when employing mitigation strategies. Previous studies on costs were evaluated from the following perspectives: “the cost to the economy of a nation and the cost of selected corrosion control measures” (17). Figure 13 lists some of the costs typically associated with corrosion (17). For this project, capital and design costs were not considered since the focus of this work is protecting existing assets. Thus, the economic analysis focused on the trade-off between control costs (i.e. repairing the anomaly, using inhibitors) and associated costs (i.e. loss of containment due to pipeline failure, pipeline capacity diminished).
Initially, the base cost of repair was estimated as $10,000 and the penalty of a pipeline failure was estimated as $1,000,000. To determine the optimal time for repair, each year was analyzed separately. In each year, the cost of repair was compared to the cost of failure, which is the product of the failure penalty and the probability of failure. If the cost of repair was lower than the economic risk of failure in a given year, it was recommended to fix the anomaly. Once the model recommends a year of repair, the probability of failure of the subsequent years is reduced to zero. For example, Figure 14 shows the total risk for each given year for a specific anomaly and how this compares to the base cost of repair. Equation 2 shows how the total risk is calculated, where the “n” subscript refers to the beginning of year n. For example, the total risk in year 1 should be calculated using the failure probability that corresponds to year 1. In year 8, the probability of failure increases such that it becomes a greater economic risk to not repair the anomaly as compared to repairing it. Thus, the recommendation is to repair the anomaly at year 8.

\[ \text{Equation 2.} \]

\[
\text{Risk of Single Anomaly, } R_n = \sum_{i=1}^{n} \left( C_{\text{repair}} + C_{\text{failure}} \right)
\]

Figure 13. Various costs associated with corrosion.

Figure 14. Cost analysis for single anomaly located at 805 m from pipeline start.
Figure 15 shows the comparison of risk between repairing and not repairing the pipelines, discounted back to the beginning of year 0. The risk of not repairing is the incremental risk that is accrued as the probability of failure increases annually. The amount of risk accumulated with repairs is the amount of proportion of the failure penalty that is accepted before the model recommends repairing the anomaly. By optimizing repairs on an economic basis, the total risk of operating the pipeline can be dramatically reduced. Other techniques, such as adding inhibitors, have the potential to reduce the cost of risk by an even more dramatic amount.

Equation 3 shows how the discounted total risk was calculated in Figure 15, where \( n \) is the beginning of year \( n \) and the summation is over the entire length of the pipeline. Since \( n \) is considered from the beginning of the year, the first value of \( n \) is 2. For the case with no repairs, Equation 3 was still used but once the anomaly was repaired, the risk for subsequent years was set to 0.

Equation 3.

![Figure 15](image.png)

Figure 15. Discounted risk comparison of repairing vs. not repairing all pipeline anomalies over time.

Lastly, Figure 16 compares the predicted annual cost of repairs vs. the cost of risk that is accepted by not employing mitigation methods. Excluding year 14, the cost of repairs is always lower than the evaluated cost of risk. Year 14 had the largest number of recommended repairs and thus the cost of mitigation slightly exceeds the amount of risk accepted. However, as Figure 12 showed, it is very common to see anomalies that are close together. Therefore, the cost to repair this segment of pipeline should be lower than what is predicted due to shared expenses, such as excavating and labor costs. Over 15 years, the economic risk that will be accrued due to corrosion is estimated at over $41 million. By implementing the recommended repair schedule, the pipeline is predicted to avoid $13.5 million in risk over 15 years.
Figure 16. Risk associated with not repairing all pipeline anomalies vs. the annual cost for repairs.
Recommendations and Conclusions

Recommendations

While the model is performing as intended, the following recommendations would be beneficial to its future users:

- Test the predictions of this model by acquiring a second set of ILI data of the same pipeline.
- Diversify the distributions available for fitting the ILI data.
- Include analysis of field data such as the effects of product chemistry, water concentration, and solids content on growth rates.
- Apply the same methodology used in this work for external corrosion.
- Determine methods to estimate the effects of external corrosion mitigation.
- Add additional failure estimation models (such as the Shell or DNV-99) as a comparison to the Modified B31G.
- Have model display not only the anomaly locations along the pipeline but also their orientation within it.

Conclusions

This model analyzes federally mandated data for pipeline owners by combining distribution fitting techniques, statistical analysis, and an economic evaluation. The model has been constructed to permit easy modifications which allow the user to make the data analysis as simple or as complicated as desired. Based on the specific pipeline data analyzed and estimated repair costs, it is predicted that approximately $13.5 million dollars of risk can be avoided by implementing an optimized repair schedule for the entire pipeline over 15 years. Based on the model output, the majority of repairs should take place between years 13-15. While the model still requires sound engineering judgement, the results can still be used to drive management and budgetary decisions. Also, as heavier crudes become more popular and general corrosion awareness increases, it is predicted that the number of anomalies per pipeline will decrease over time.
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