An Exploratory Data Analysis Of Pipeline Coating Degradation

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Abstract

Pipeline coatings can be constructed from a multitude of materials, all of which aim to provide a physical barrier between a pipeline and the external environment. Naturally, understanding the degradation characteristics of these different coating materials is critical, as with the onset of coating degradation comes metal degradation, i.e. corrosion. External corrosion remains as one of the major threats to the integrity of pipelines worldwide.

Since coating degradation can occur for many reasons (from discrete events such as impact damage during construction, to age related processes such as embrittlement or loss of adhesion [ ]), modelling and prediction of degradation is a challenging task. In practice, it is more common for pipeline operators to measure the condition of a coating periodically (using visual inspection, or above ground survey techniques) in order to monitor its degradation over time. Unfortunately, these coating survey data are distributed across multiple pipeline operators, inspection vendors and service providers, meaning that there is no single data repository from which population trends can be established.

As an alternative, we present a brief exploratory data analysis (EDA) conducted on a large repository of historical in line inspection (ILI) data for around 5,000 unique assets with known coating materials. The purpose of the EDA is to investigate whether the prevalence of external corrosion – as observed over a large population of pipelines – can be used to infer the degradation characteristics of the materials. The EDA makes use of 18 million instances of external corrosion detected in over 6,000 metal loss inspections

EXPLORATORY DATA ANALYSIS (EDA)

COATING CATEGORIZATION

Although many different coating materials are recorded within the data repository, we group the coatings into five broad categories: Asphalt, Coal Tar Enamel (CTE), Tape, Fusion Bonded Epoxy (FBE) and 3 Layer Polyethylene/ Polypropylene (3LPE/PP). Note that coatings applied exclusively to the field joint area of a pipeline (approximately 200 mm either side of the girth weld) are not considered in this analysis.

Figure 1 shows the distribution of the coating categories according to decade of construction and reveals a clear trend – namely, the gradual phasing out of the "first-generation" coatings (Asphalt and CTE) and the concurrent introduction of the "second generation" and "third-generation" coatings (FBE and 3LPE/PP). Tape coatings stand the test of time and retain a sizeable proportion of the population throughout the years.

CONDITION METRICS

Condition metrics are single valued, numerical descriptors for the condition of a pipeline. In the present case, two condition metrics are selected as proxy variables for the coating condition.

The first is the anomaly density, defined as the number of external corrosion anomalies divided by the total pipeline surface area. High anomaly densities imply that the coating has degraded in multiple locations, while low anomaly densities suggest more sporadic coating degradation.
The second metric of interest is the relative corroded area, defined as the total corroded area (with each individual anomaly area approximated as length × width) divided by the total pipeline surface area.

While anomaly density correlates strongly with relative corroded area, each metric is useful in its own right. There are cases, for example, where a pipeline has a relatively low anomaly density, but where each individual anomaly has a high surface area (this may occur due to coating disbondment over an extended area). The use of both condition metrics also accounts for differences in ILI technology. Magnetic Flux Leakage (MFL) technology, for instance, tends to report a greater number of individual anomalies (each with a relatively small area) compared to Ultrasonic (UT) technology, which is more likely to report an extensive corroded area.

Note that in the present analysis, all external corrosion anomalies are counted, irrespective of their distance to girth welds. While it is acknowledged that different external corrosion activity can occur in the pipe body and field joint areas, further investigation of the dataset shows that this is relatively uncommon. When the two populations are separated and the condition metrics are recalculated for each population, the metrics are strongly positively correlated, implying that a pipeline with significant corrosion in the pipe body is more likely to have significant corrosion in the field joint area, and vice versa.

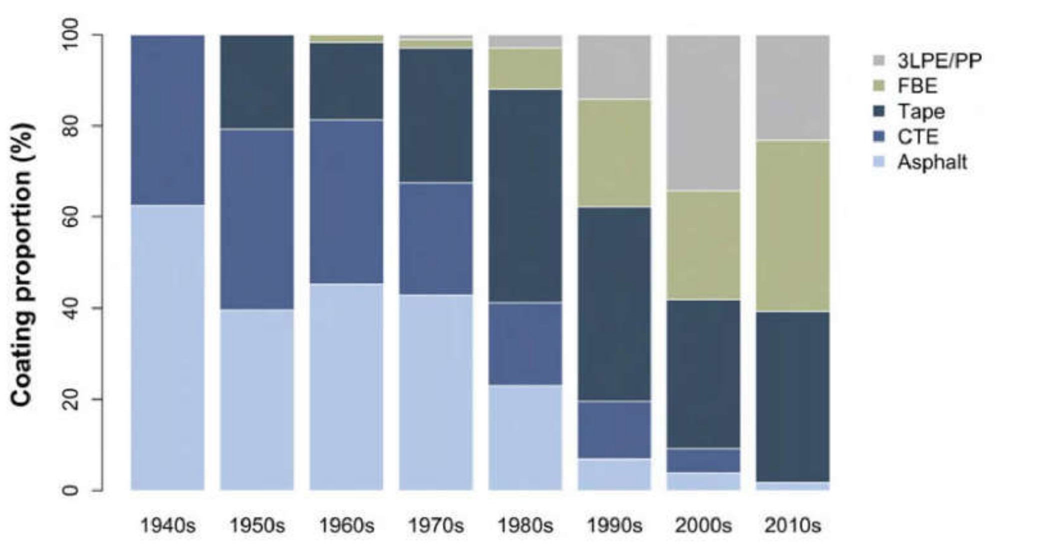

Figure 1: Distribution of pipeline coatings by decade

The distributions of the condition metrics are shown in Figure 2, on a logarithmic scale. The scale highlights that the pipelines vary extensively in their condition, with the lower orders of magnitude representing pipelines in an almost perfect condition, and the higher orders representing pipelines with extremely pervasive corrosion. Nevertheless, there are comparatively few pipelines in the latter category. The median values lie at only 0.0126 m 2 for anomaly density (¬approximating to one anomaly for every 80 m2 of pipe surface area) and 2.51 × 10-5 for relative corroded area (less than 0.003% coverage).

The next step is to understand how these distributions vary according to the coating category (Figure 3). The box plots show the positions of the minimum, lower quartile, median, upper quartile, and maximum condition metric values for each category, in addition to any outliers (defined as 1.5 × interquartile range above or below the upper and lower quartiles respectively).

Notable in Figure 3 is the high variance in each distribution. This variability is entirely expected, however, since the problem is multivariate; the condition of a pipeline depends on far more than just the coating. Confounding variables arise due to cathodic protection, local ground conditions (e.g. soil resistivity), electrical inference, locations of crossings, and a host of other environmental and economic factors.

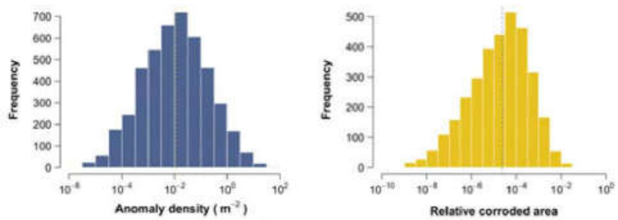

Figure 2: Condition metric distributions (medians superimposed as dashed lines)

Nevertheless, visualizations such as those in Figure 3 can reveal interesting trends. For example, it is clear that the pipelines with first-generation coatings (Asphalt, CTE and Tape) have generally higher values of condition metrics, compared to the more modern second-generation (FBE) and third-generation (3LPE/PP) coatings. This agrees with our intuition, since we expect second and third-generation coatings to provide better protection than firs- generation coatings, due to advances in materials and application methods.

Of course, this does not imply that all future pipelines should be designed with second or third-generation coatings. All coatings have their advantages and disadvantages. The second and third-generation coatings are, for example, far more susceptible to mechanical damage, which can result in localized corrosion at the site of the damage. Since mechanical damage typically occurs at the beginning of a pipeline's life during storage, transport or construction, the exposure time for the corrosion is maximized. This could explain some of the high outliers observed for these coatings.

We must also be particularly careful about the influence of age, which correlates strongly with the coating type (Figure 1) [1]. Due to this correlation, it is difficult to establish whether the trend in condition is caused by the coating itself or the age of the pipeline. All other things being equal, an older pipeline is more likely to have experienced adverse conditions that led to corrosion.

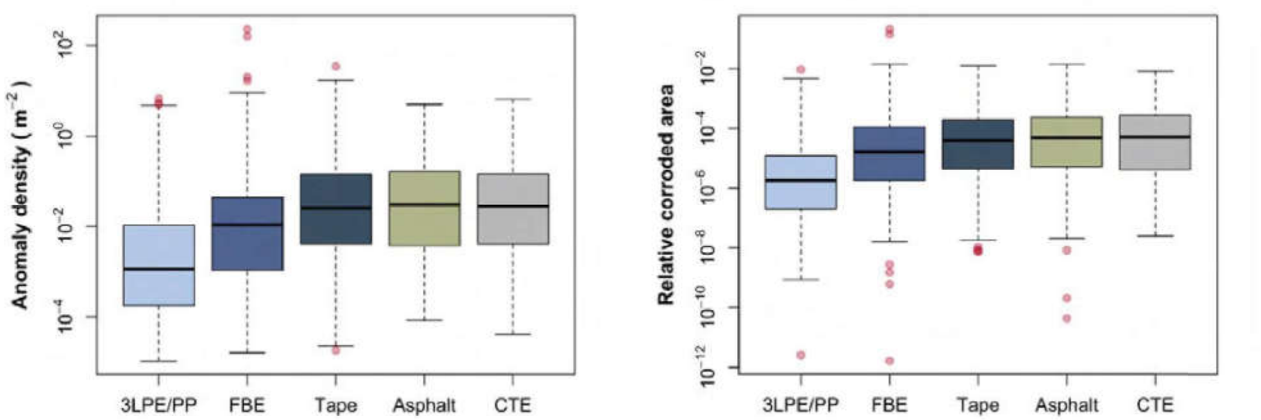

Figure 3: Condition metrics vs. coating type

COATING DEGRADATION

In order to measure degradation, we use the concept of a "degraded" pipeline coating, defined using condition metric values seen in the general population. An intuitive choice is the median value of each metric. Therefore, we set two thresholds, and assert that a pipeline must exceed either one (but not necessarily both) in order for the coating to be defined as "degraded". Explicitly, a pipeline is considered to have a "degraded" coating if either the anomaly density exceeds 0.0126 m 2 or the relative corroded area exceeds 2.51 × 10-5.

After labelling pipelines in this manner, we analyze how the proportion of "degraded" vs. "non-degraded" coatings changes with the age of pipelines (the age of a pipeline is calculated as the difference between the inspection date and the construction date). The proportions are visualized in Figure 4 across five 5 year bins and a final bin for pipelines aged 25 years and over (there is rapidly diminishing representation of 3LPE/PP coatings beyond this age). Note that CTE and Asphalt are combined into a single group as they share similar distributions of age and condition metrics (evidenced in Figures 1 and 3).

At first glance, the poorest performing coating type appears to be FBE, with the probability of observing a degraded FBE coating increasing steadily with pipeline age. While this may be unexpected evidence of time dependent degradation, we should be cautious about jumping to this conclusion. Naturally the ages of pipelines within the database are highly correlated with the construction dates (older pipelines were constructed longer ago), meaning that the trend may simply reflect improvements in construction practices and material properties over time. It remains plausible that the majority of coating damage for these pipelines actually occurred at the beginning of their service lives, with minimal or no degradation thereafter.

By contrast, the best performing coatings are the third generation 3LPE/PP systems, which are minimally degraded and exhibit no clear evidence of time dependent degradation prior to the 25 year mark. Again, the increase in degraded coatings after 25 years may reflect construction practices and material properties from the corresponding time period, rather than time dependent degradation. It may also be a consequence of small sample size.

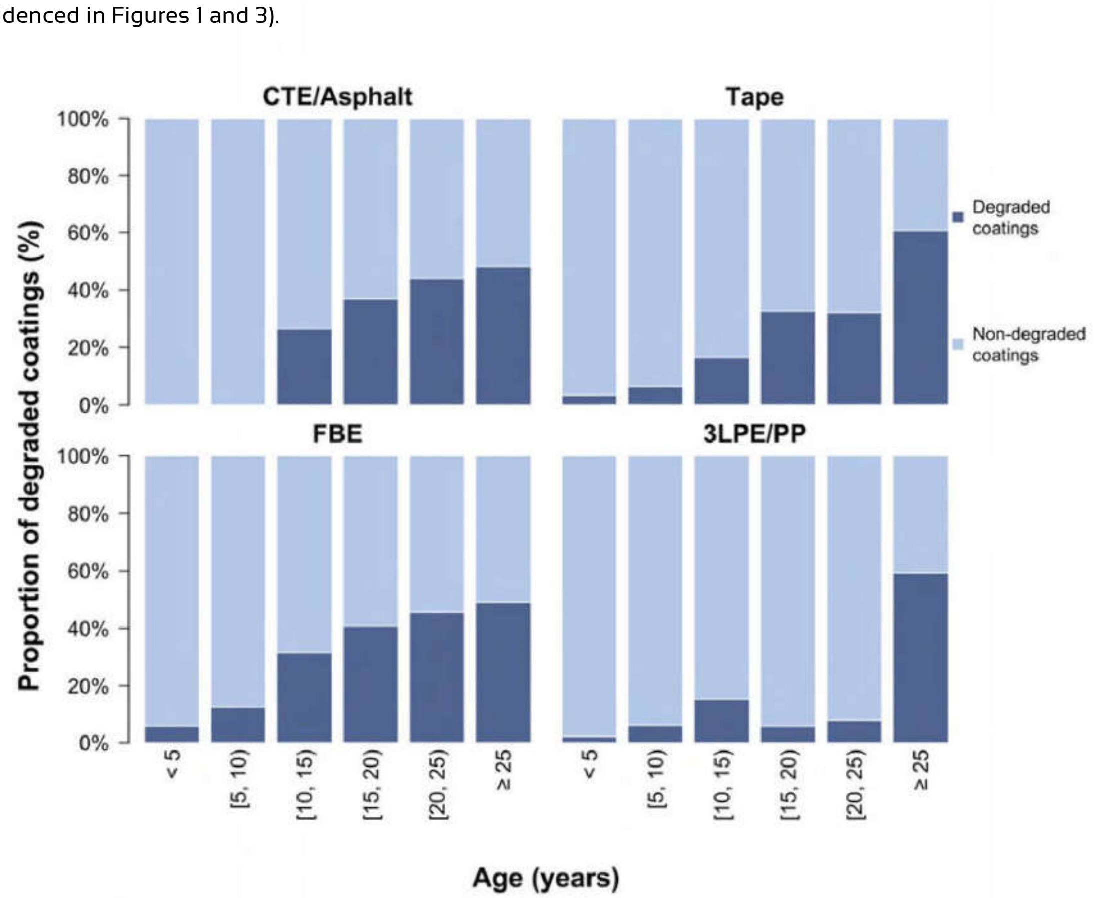

Figure 4: Proportion of degraded coatings vs. pipeline age

While the same confounding effect of construction date may also be at play for the CTE/Asphalt and Tape coatings, prior knowledge of these coating materials gives more credibility to the observed trends. Specifically, the coatings are less susceptible to mechanical damage during construction, but after a time lag are more prone to in service degradation. It is certainly plausible that the absence of degraded CTE/Asphalt coatings less than 10 years of age – followed by a decade by decade increase in degraded coatings thereafter – reflects a 10 year time lag prior to the onset of degradation. Likewise, it is plausible that the trend for Tape coatings reflects degradation without a measurable time lag. Further investigation is required before either of these trends can be verified (and quantified) with confidence.

CONCLUSIONS

Despite the highly confounded nature of the problem, the EDA reveals some interesting trends amongst different coating categories. Most notably, pipelines with first-generation coatings (Asphalt, CTE and Tape) are observed to be in a poorer condition than those with second and third-generation coatings (FBE and 3LPE/PP), and while this trend may reflect the age of pipelines, it is considered highly likely that it also reflects the efficacy of the coating system itself.

The results also hint at time dependent coating degradation amongst Asphalt, CTE, Tape and FBE coatings, although the influence of construction date may be confounding this interpretation. The same cannot be said for third-generation coatings like 3LPE/PP, however, for which there is no clear evidence of degradation with age.

External corrosion and coating degradation are complex phenomena, and fully inferring the causal chain at this stage proves difficult. However, with an expanding data repository (expected to exceed 20,000 metal loss inspections within the next year) and ongoing efforts to obtain higher resolution data, it is inevitable that variability will reduce and trends will become more distinguished. We conclude that the use of ILI data for understanding and characterizing coating degradation is a promising avenue for exploration, with implications for design, construction and integrity management of pipelines.

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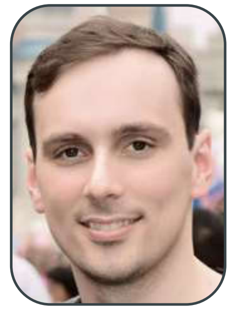

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