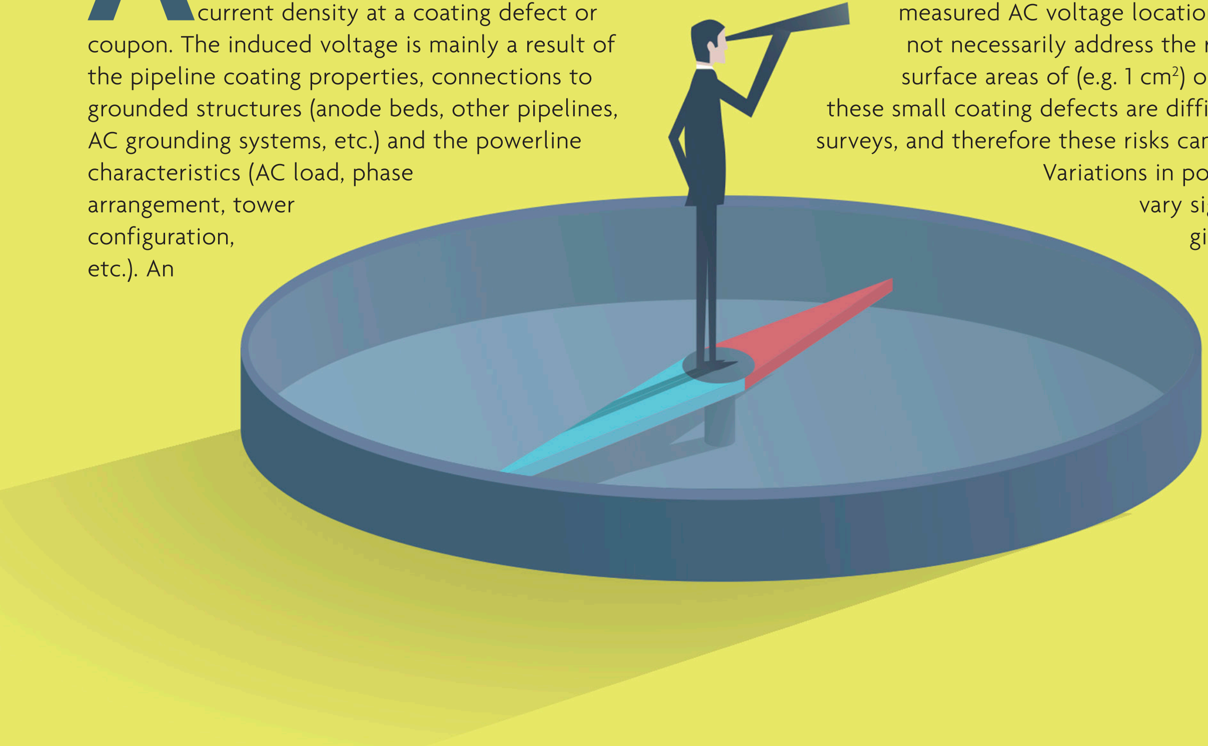
AC corrosion: looking in the right direction

Christophe Baeté, Belgium, and Gerald Haynes, USA, Elsyca, explains how remote monitoring and computational modelling can help operators transition into the digitalisation of pipeline corrosion control.



According to the NACE SP21414 and ISO18086 standards, AC corrosion risks on pipelines requires knowledge of both the AC and CP current density at a coating defect or coupon. The induced voltage is mainly a result of the pipeline coating properties, connections to grounded structures (anode beds, other pipelines, AC grounding systems, etc.) and the powerline characteristics (AC load, phase arrangement, tower configuration, etc.). An accurate interference and mitigation design engineering study should include all these variables.

Simply installing AC groundings at the highest measured AC voltage locations on the pipe, does not necessarily address the risks at all the small surface areas of (e.g. 1 cm^2) on the pipeline, as these small coating defects are difficult to detect during surveys, and therefore these risks can be overlooked.

Variations in power line load may vary significantly during a given period, due to diurnal, monthly

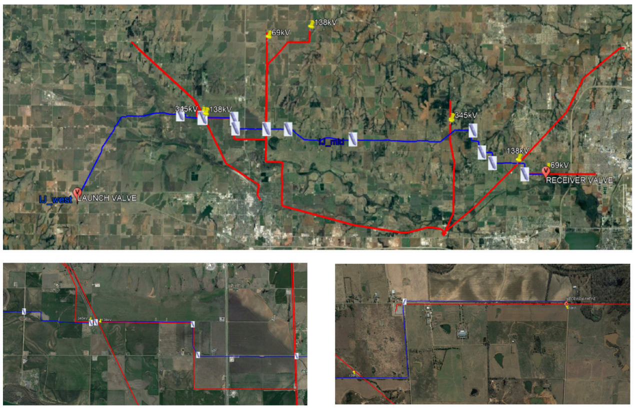


Figure 1. Pipeline routing (blue) in collocation with high voltage AC power lines (red) with ER probes and with EMF/LEF locations.

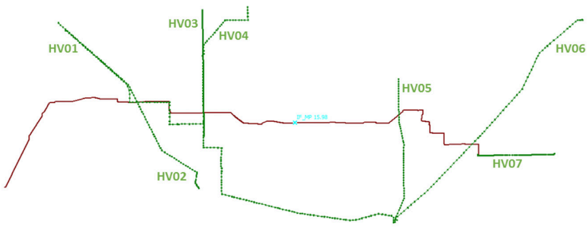


Figure 2. Corresponding V-PIMS computational model.

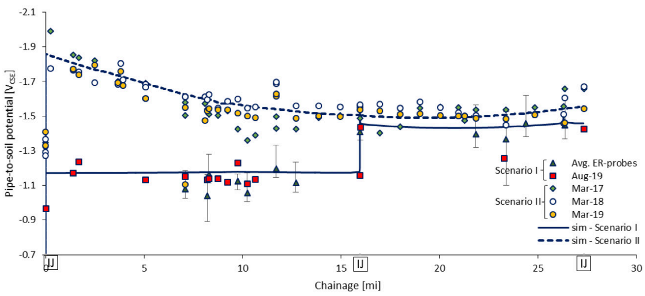


Figure 3. Pipe-to-soil ON potentials before and after repair of insulation joint (IJ).

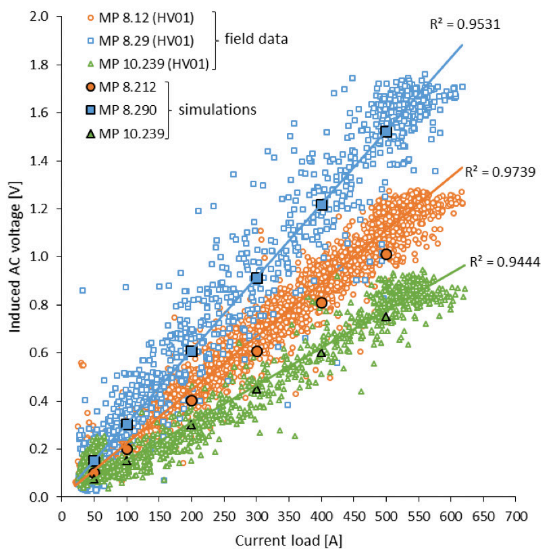


Figure 4. AC potential fluctuations (measured and simulated) as function of power line load.

or for seasonal (winter or summer) fluctuations. These variations are captured by remote monitoring devices, but their installation locations should be carefully chosen.

Pipeline case

A 27 mile-long 8 in. pipeline, in co-location with seven high-voltage AC powerlines, is used in this case study. The pipeline collocates for 2 miles with a paralleling 345 kV powerline in the west and another 1 mile stretch is collocated with a 69 kV power line in the east. The remaining powerlines are mainly crossing the pipeline at different locations.

Computational modeling was performed using the Elsyca V-PIMS software to validate:

- The effectiveness of the AC mitigation system.
- The operational conditions of the CP system.
- The overall AC corrosion risk.

The pipeline was installed in 2010. In 2016 several AC corrosion anomalies were detected during an ILI MFL inspection run. An AC mitigation system was then installed in 2017 to mitigate the induced AC voltages and AC current in the pipeline. The AC corrosion risk is monitored by eleven electrical resistance (ER) probes connected to the pipeline and eight electromagnetic field/longitudinal electrical field devices (EMF/LEF) installed adjacent to the power lines. The former device measures the corrosion rate and electrical pipeline parameters (AC voltage, AC current density, DC current density and pipe-to-soil potential) via a probe, whilst the latter device indirectly measures the power line load and phasing. The devices were installed as depicted in Figure 1.

Model calibration

Field data and pipeline properties are used to calibrate the computational model such that the computed simulation results are aligned with real-world data. Recordings from the LEF/EMF devices permitted the accurate calibration of the power line load and phasing conditions.

The pipeline coating resistance/impedance of 23 kOhm.m^2 for the FBE coating was computed by iterating on the pipe-to-soil ON potentials (Figure 2) and AC voltage on the pipeline (Figure 3). For the pipe potentials two different CP scenarios were considered, as the insulation joint (IJ) located halfway along the pipeline route was compromised for a period of time. The AC voltage readings over time were taken in the western parallelism where ER-probe data and EMF/LEF data was available.

The ILI anomaly size of corrosion features exceeding 10% metal loss were included to refine the coating resistance at specific spots. There was a good correlation between the measured and simulated data. Soil resistivity measurements were taken at 10 selected locations. The soil resistivity at the pipeline depth varies between 3.5 Ω-m and 253 Ω-m with the logarithmic mean value of 13 Ω-m.

Pinpointing hot-spots

The profile of the AC induced voltage along the line

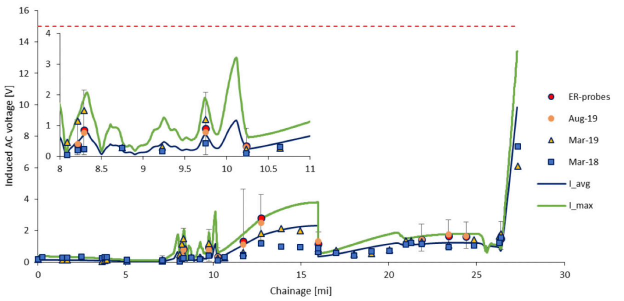


Figure 5. Simulated (full line) versus measured (markers) induced AC voltage under average and maximum power line load.

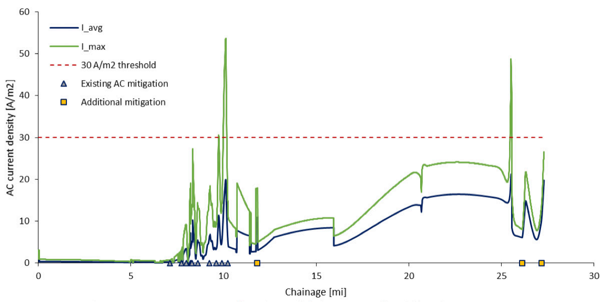


Figure 6. Simulated AC current density profile along the pipeline route under average and maximum power line load.

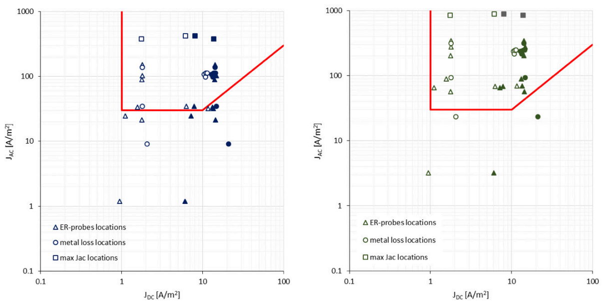


Figure 7. AC corrosion risk at locations of interest under average (left) and maximum AC powerline load (full markers are under elevated CP).

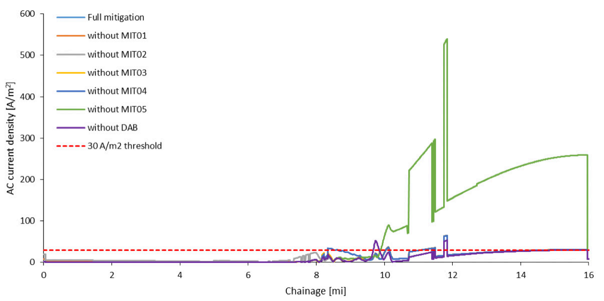


Figure 8. Effect of malfunctioning AC grounding on the AC current density (west part).

with the mitigation in place was simulated and compared with survey and monitoring data at various times. Under maximum recorded powerline load the induced voltage reaches 4 V just before the insulation joint installed halfway along the pipeline route, and 13 V at the most eastern part at the receiver valve. Note that there are no ER probes installed at highest peaks in the AC voltage. The AC current density resulting from the AC voltage and local soil resistivity reaches values above 100 A/m^2 in locations where monitoring devices are absent. In Figure 6 it is clearly seen that the AC grounding is required downstream of the parallelism in the west.

The simulated AC and DC current density along the pipeline are plotted in the AC corrosion risk diagram according to ISO18086 standard for those locations where ER-probes were installed, and metal loss features were detected, and maximum AC corrosion activity is determined from the computational simulations. Figure 7 demonstrates that the computational model predicts AC corrosion risks at the most vulnerable locations along the pipeline.

Mitigation

Acknowledging the risks and identifying the most vulnerable locations allows further improvements with the AC mitigation system. In the first instance the sensitivity of the existing mitigation design was investigated through computational modeling. Figure 8 shows that the AC grounding MIT05 system is potentially responsible for an increase in the AC current density (by a factor of five) when it is not functional.

Permanent monitoring of drainage current through the grounding systems or monitoring the pipeline potentials was recommended. Finally, three additional AC grounding systems have been designed to mitigate the risks and ensure continued pipeline integrity. At maximum power line loads the computed maximum current density does not exceed the 100 A/m^2.

Conclusions

New pipelines can become easy victims of AC corrosion with increased risks when they are not properly assessed and mitigated. The risk assessment must be based upon reliable data gathered, but also gathered in the correct locations. The AC mitigation system should be design where hot-spot areas actually occur on the pipeline.

As demonstrated in this case study, specific peaks in the AC current density can occur at unexpected locations and at remote distance from the parallelism between the pipeline and power line. Computational modeling can accurately calculate these risks and predict the potential for AC corrosion attack for the entire pipeline route, on the proviso that that the models are correctly and suitably calibrated. This ultimately results in an overall cost reduction, since a considerable amount of inspection digs, pipeline repairs and monitoring devices can be avoided.