Lessons Learned during 10 Years of ECDA Application

S.M. Segall, P. Eng.
R.A. Gummow, P. Eng.
D. Fingas
Corrosion Service Company Limited
9-280 Hillmount Road
Markham, ON L6C 3A1 Canada

John Shore, P. Eng.
Union Gas Limited
A Spectra Energy Company
50 Keil Drive North
Chatham, ON N7M 5M1 Canada

ABSTRACT

This paper summarizes the results of ten years of External Corrosion Direct Assessment (ECDA) application on more than 100 projects and includes a number of important lessons learned during the process.

The large majority of the ECDA projects resulted in "clean bills of health" for the assessed pipelines. The actual number of direct examinations seldom exceeded the minimum number of digs required by NACE Standard SP 0502-2010.[1]

Topics like selection of the ECDA regions, influence of pipe depth and local soil resistivity in classifying and prioritizing Direct Current Voltage Gradient (DCVG) indications, dealing with "clipped" gradients and dealing with "false" severe Close Interval Potential Survey (CIPS) indications are discussed in detail in this paper.

Keywords: ECDA, CIPS, DCVG, DC Coupons.

INTRODUCTION

The ECDA was introduced in 2002 under NACE Standard RP 0502-2002.[2] The Standard offered the safety authorities and the pipeline operators a well-structured step-by-step engineering assessment to be used as a common ground to satisfy the pipeline integrity requirements. The Standard was at the same time conservative, especially in terms of minimum number of digs, and flexible, especially in terms of letting the operator select its own identification, classification and prioritization criteria.

Even prior to the publication of the Standard, significant effort was invested by the pipeline operators and consulting companies to "learn and understand" every requirement of the Standard and to develop the best strategies to address these requirements.

Some of these strategies were never applied in real assessments. We developed a structured approach in dealing with coating holidays consisting of an initial macro-survey to identify areas with “bad” coating, followed by a second DCVG or ACVG survey to locate and classify the holidays. We are still waiting for the ideal conditions to justify this approach.

Other strategies, such as using an integrated CIPS/DCVG survey in conjunction with a proprietary formula for calculating the %IR were successfully applied and helped dealing with the most unexpected situations encountered in the field.

To celebrate more than 10 years of ECDA application on more than 100 projects, this paper will try and re-enact several important battles in the never ending “Pipeline Integrity War” and also to summarize some of the lessons learned during the process.

THE FIRST YEARS. FIGHTING THE “ECDA REGIONS” TEMPTATION

The new ECDA Standard provided a thorough analysis of the various factors to be considered during the pre-assessment and their influence on the accuracy of the process. The recommended solution, for addressing sections of line affected by such factors, is to consider them as separate ECDA regions.

The unexpected consequence of this excellent technical approach was the false perception that the quality of a pre-assessment increases linearly with the number of ECDA regions.

Our first pre-assessment issued in 2004 will remain in the company’s history with four ECDA regions along a 4.26 km (2.65 miles), a record never reached again.

A more realistic analysis indicated that an excessive number of ECDA regions would result in unwarranted digs, should indications prioritized as “Scheduled Action Required” be found along various regions. However, artificially reducing the number of ECDA regions may eventually result in an even worse situation. Paragraph 5.6.2 of SP0502-2010 states that if the remaining strength of a defect is below the accepted level for the pipeline segment, repair or replacement is required and in addition “alternative methods of assessing pipeline integrity must be considered for the entire ECDA region in which the defect or the defects were found, unless the defect or the defects are shown to be isolated and unique in a root-cause analysis”. Looking for a different assessment for an entire line considered as one ECDA region, after finding a very severe defect would be a very expensive endeavor.

<u>The lesson</u>: Use the right number of ECDA regions based on corrosion risk and reliability of the indirect inspections tools.

THE “ADOLESCENCE” YEARS. THE QUEST FOR THE “DEEPEST PIT”

The ECDA process was still struggling to prove itself and finding a significant threat for pipeline integrity using ECDA methodology was considered to be a major argument for general recognition. As a result, the quest for the “deepest pit” threatening the pipe was in full swing.

An ECDA process was conducted in 2007 on an NPS4 pipeline in northern Ontario.[3] The results of the survey, from chainage 2000 m to chainage 2500 m, are shown in Figure 1.

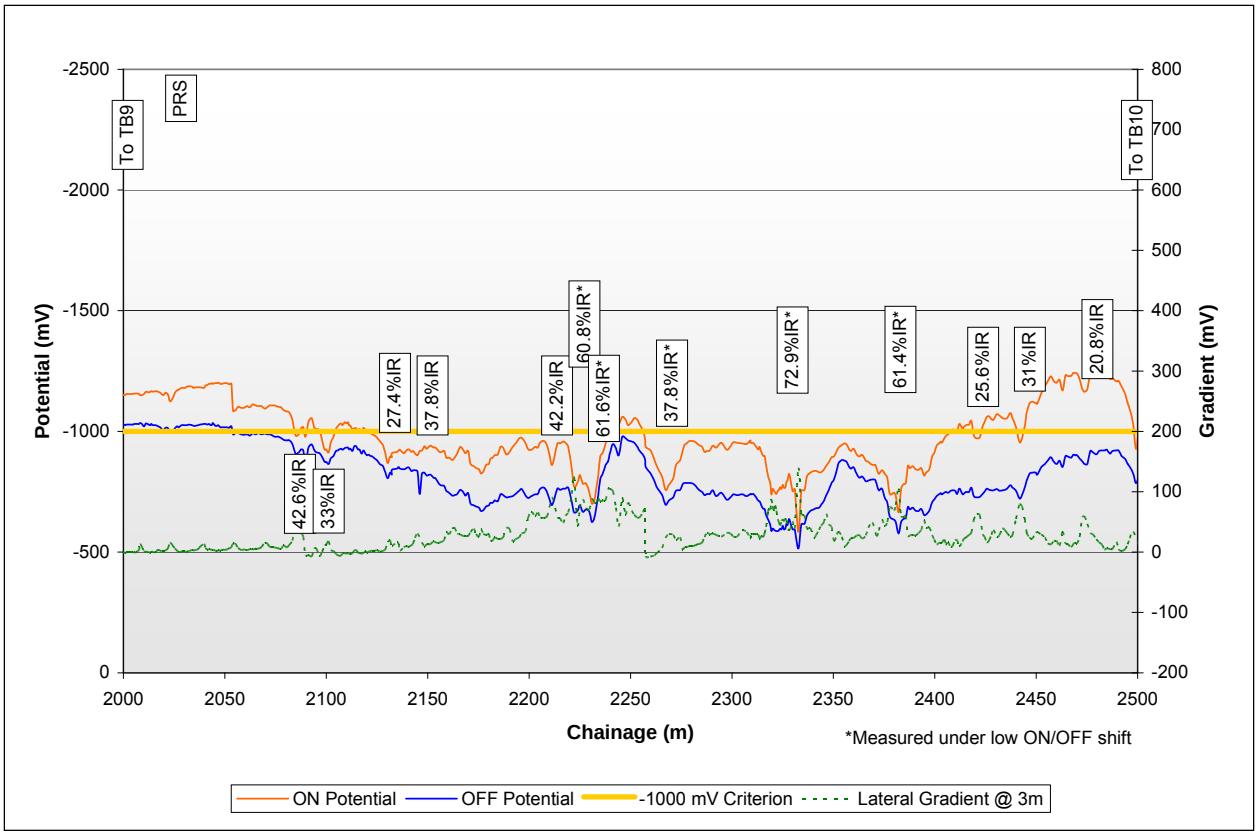

Figure 1: 114 mm (4 in) Lateral. Ch. 2000 m to 2500 m. CIPS/DCVG Profile

The survey displayed a severe DCVG indication at chainage 2382.2 m (i.e. 61.4%IR) recorded with a relatively low potential shift (i.e. 89 mV) in conjunction with a severe CIPS indication (-577 mV_{CSE}).

The direct examination was performed on July 24, 2009. The pipe condition after coating removal is shown in Figure 2.

Figure 2: 114 mm (4 in) Lateral. Direct Examination. Pipe Condition

The deepest pit was 71% through wall.

Even more importantly, less than 100 m downstream, the potential shift increased from 89 mV to 299 mV and interpolation of the data may have downgraded the indication to moderate or even minor. The 12.3 km long pipeline displayed more than 250 DCVG indications with extended areas having very low protection levels. Twenty-one indications were prioritized as "Immediate Action Required" and seventy-nine indications were prioritized as "Scheduled Action Required". If this indication had been classified as moderate or minor, it almost certainly would not have been included in the list of direct examinations.

The lesson: Under severe variations in soil resistivity, the normal practice of calculating the %IR by measuring the gradient to remote earth at the indication and interpolating pipe-to-soil potentials measured to remote earth at adjacent test posts could result in significant errors. Such situations must be addressed with extra caution, either by directly measuring the pipe-to-soil potential to remote earth at the DCVG indication or using an integrated CIPS/DCVG survey and the associated calculations.

THE "MATURITY" YEARS. AVOIDING ERRORS DURING THE INDIRECT INSPECTIONS

The ECDA process was becoming routine, but possible errors during the indirect inspections could still have been costly, either in the number of direct examinations or even in terms of pipeline integrity.

A close interval survey was conducted in 2010 on a 323.9 mm (12 in) dia. natural gas line in Eastern Canada.[4] The last section of the line was mainly protected by magnesium anode banks. The field crew started surveying this section by simultaneously interrupting the rectifiers and the influencing anode banks. Partial results of the survey are shown in Figure 3 for a portion of the pipeline.

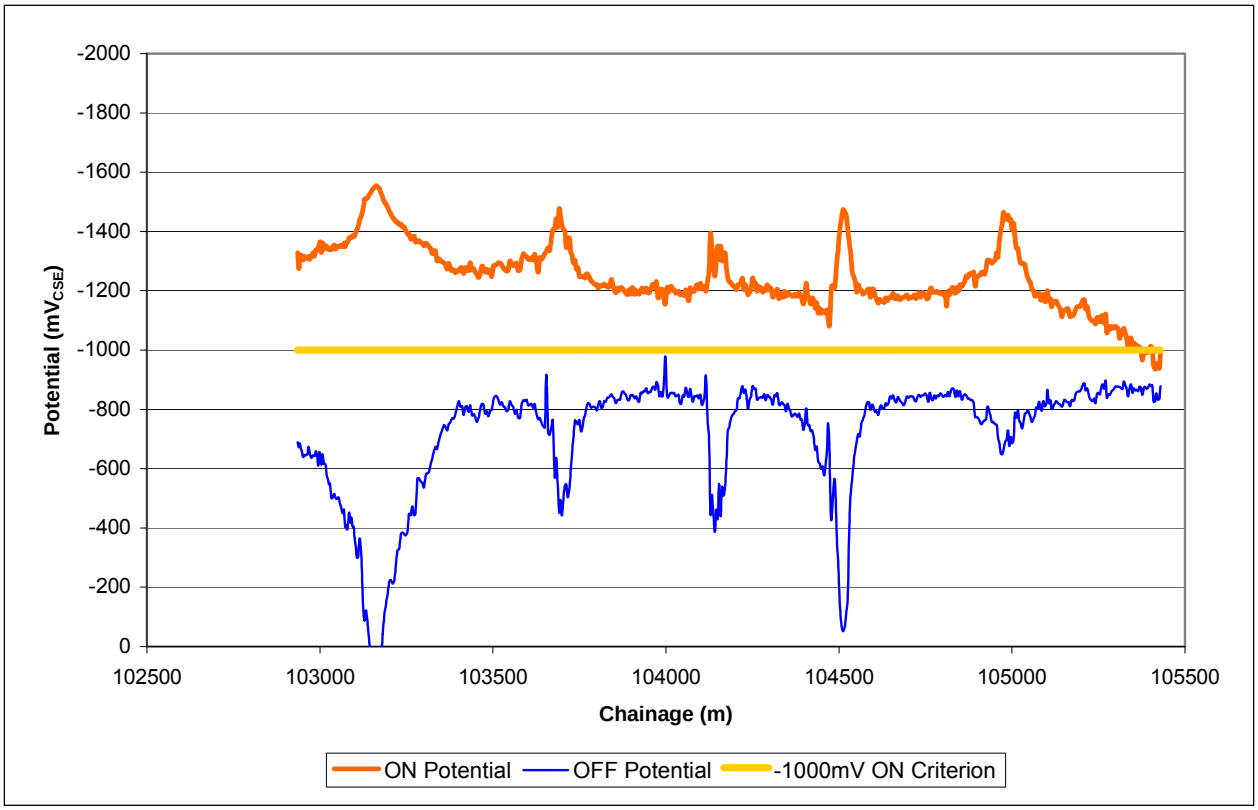

Figure 3: 323.9 mm (12 in) Dia Line. Recorded ON/OFF Potentials

The pipeline displayed local OFF potentials as electropositive as +136 mV$_{CSE}$, with average values around -800 mV$_{CSE}$. At the first analysis, such potentials would require direct examinations, significantly increasing the number of digs.

An in-depth analysis indicated that the actual reason for the extremely low potentials was rectification of the AC induced voltages, during interruption of the magnesium anode banks. The interrupter had a diode, across its terminals, as shown in Figure 4, which rectified the AC voltage during the OFF cycle, causing the pipe potential to shift in the electropositive direction.

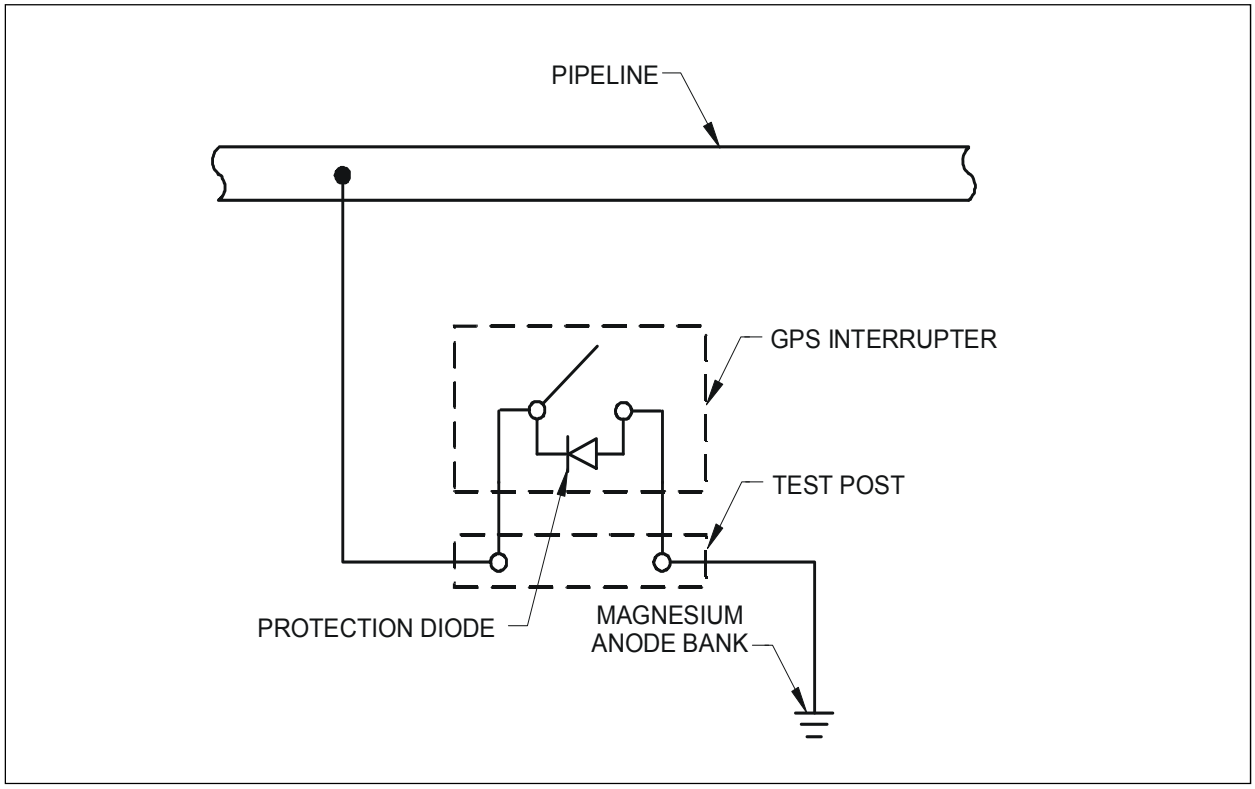

Figure 4: Rectification by Protection Diode during the OFF Cycle

During the survey, the interrupter was connected as shown, severely reducing the protection level of the pipe and protecting the magnesium anodes.

<u>The lesson</u>: Under AC interference conditions, the normal practice of interrupting anode banks shall be reconsidered. Errors can occur either due to rectification of AC voltages or also due to an excessive level of AC voltages that exceed the filtering capacity of the data logger.

A second possible error was avoided during an integrated CIPS/DCVG survey conducted in 2012 on an NPS2 gas lateral in northern Ontario.[5] The pipeline was protected by directly connected magnesium anodes. An existing resistance bond, connected between the lateral and mainline, was draining 1.1 A back to the mainline impressed current systems. The results of the survey are plotted in Figure 5. The line shown at -1000 mV_{CSE} represents the chosen criterion for CIPS indications on pipelines protected by directly connected magnesium anodes, with all influencing rectifiers turned OFF.

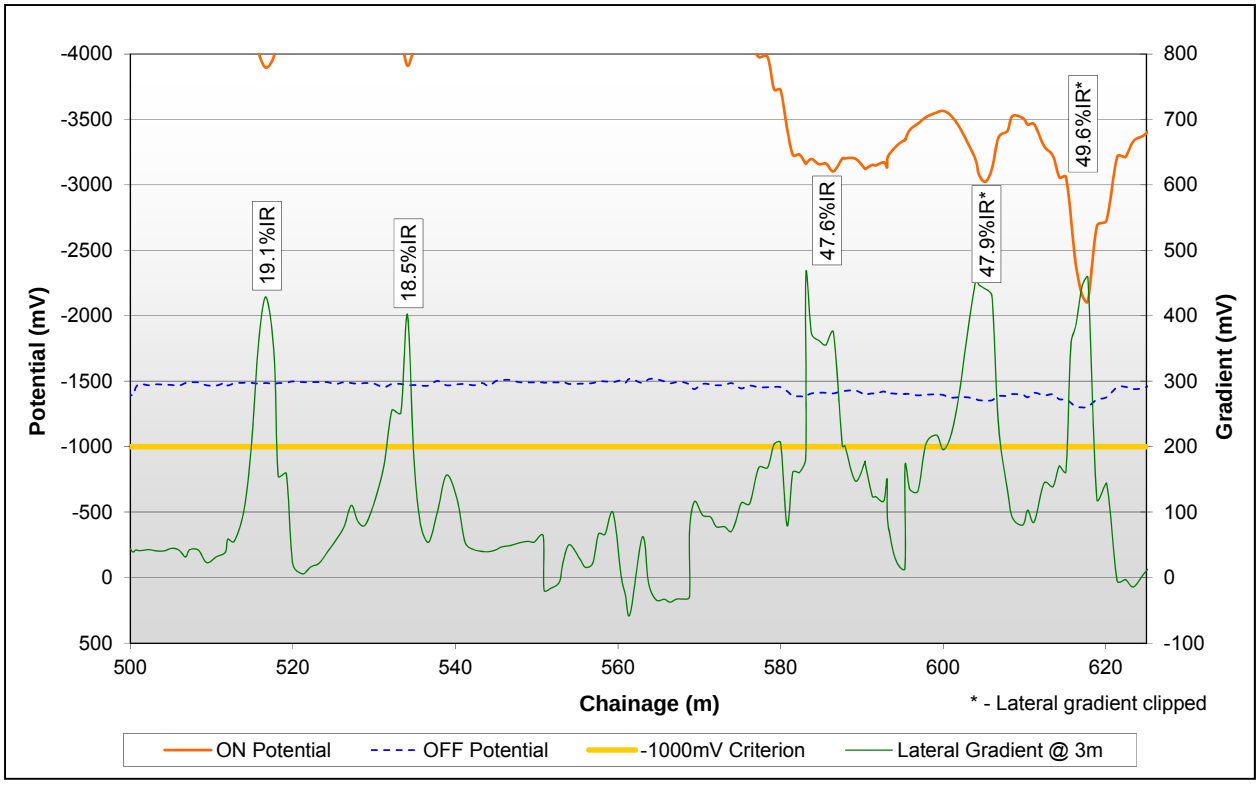

Figure 5: NPS2 Line. Results of CIPS/DCVG Survey with "Clipped" DCVG Gradients

A superficial look at the graph would indicate five DCVG indications, with the highest percentage IR (i.e. 49.6%IR) recorded at chainage 617.8 m. A careful review of the graph indicated gradient shifts close to -500 mV, the limit of the measurement range of the "Hexcorder Millenium"[ǂ] two-channel data logger.

The numeric data shown in Table 1 confirmed that the ON gradient was "clipped" at -500 mV_{CSE}, resulting in a lower %IR and an underestimation of the coating damage. The "clipped" locations were subsequently marked on the graphs using an asterisk (*).

Table 1
Excerpt of CIPS/DCVG Data with "Clipped" DCVG gradients

Chainage (m)	ON Potential (mV)	OFF Potential (mV)	Lateral Gradient @ 3m	
			ON	OFF
615.7	-2758	-1335	-382.7	-27.4
616.3	-2398	-1307	-435.7	-51.8
617.1	-2157	-1300	-500.0	-54.0
617.8	-2110	-1305	-500.0	-41.6
618.9	-2683	-1359	-139.3	-19.4
620.1	-2730	-1378	-159.8	-15.9

The easiest way to deal with this type of error is to turn OFF the foreign rectifier energizing the influencing groundbed and to conduct a separate DCVG survey. Since this solution could not be applied (i.e. the foreign rectifier could not be turned OFF during the foreign company survey), an increase to the next

[ǂ] Trade Name.

severity category in terms of %IR was conservatively applied at these locations as an alternative solution. For example, the "clipped" DCVG indication at chainage 617.1 m, displaying a %IR of 49.6% and classified as "moderate" was upgraded to a "severe" DCVG indication.

The lesson: DCVG indications should be correlated with the CIPS profile. Very high ON potentials could hide "clipped" indications, while very small ON/OFF pipe-to-soil potential shifts could also result in erroneously low IR percentage.

THE "WISE" YEARS. EXTENDING ECDA METHODOLOGY TO OTHER APPLICATIONS

The use of ECDA reached the "critical mass" stage and was starting to expand in a chain reaction to other applications in the industry.

In-line inspections were conducted in 2002 and 2006 on an NPS10 gas line in northern Ontario.[6] Based on the prioritized excavation response plan, 49 digs were performed under the Phase 1 and Phase 2 responses[(1)] and a total of 62 digs remained to be performed under Phase 3 response. Prioritizing these Phase 3 digs has become extremely important both in terms of allocating pipeline owner resources and ensuring a thorough pipeline integrity assessment.

Subsequently, using an ECDA approach based on the results of the previous digs as prior history of corrosion in conjunction the results of CIPS and DCVG surveys was considered an attractive prioritization solution.

As a first step, the data collected along the line during the 2010 CIPS/DCVG survey were aligned with the 2006 ILI data. One example of the resulting aligned data is shown in Figure 6.

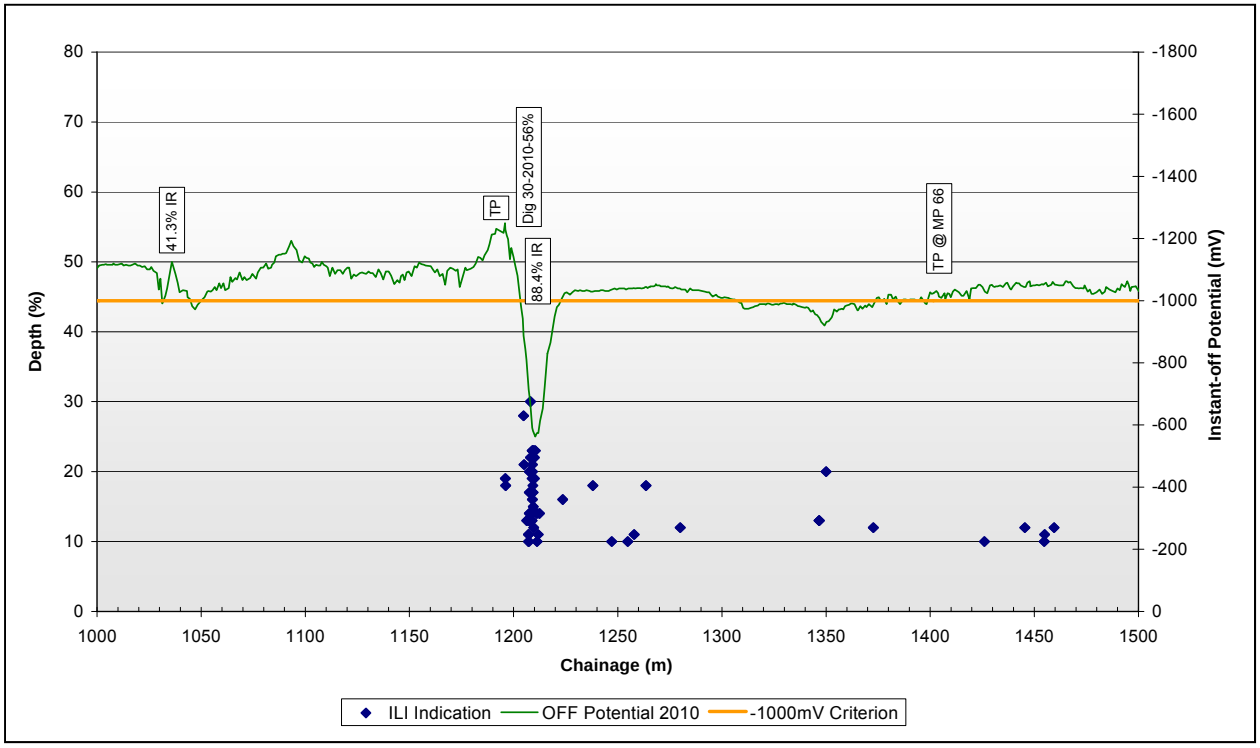

Figure 6: NPS10 Line. Ch. 1000 m to 1500 m. ILI/CIPS/DCVG Aligned Data

(1) The purpose of Phase 1 and Phase 2 ILI responses is to identify and excavate any locations that show potential for imminent (Phase 1) or short term (Phase 2) failure.

The findings of each existing ILI dig were then analyzed in conjunction with the CIPS/DCVG data in order to develop an adequate prioritization protocol. For example, Figure 6 indicates that dig 30-2010 was performed in this section at chainage 1209.3 m. A 56% through wall pit was found, which correlated well with a CIPS indication (-560 mV_{CSE}) and a DCVG indication (88.4%IR).

The next step was to classify the various types of indications. The depth of the pits found at the ILI digs was used to identify and classify any prior history of corrosion (PHC), according to the following criteria:

- Minor: 25%[(2)] to 44% pit depth, within 100 m of the ILI dig
- Moderate: 45% to 59% pit depth, within 100 m of the ILI dig
- Severe: 60% and greater pit depth, within 100 m of the ILI dig

A very conservative prioritization protocol was then developed based on an ECDA approach, in conformance with NACE Standard SP0502-2010.

Finally, the proposed protocol was applied to the remaining 62 digs. The locations prioritized as Immediate Action Required (I) and Scheduled Action Required (S) were expected to display severe or moderate corrosion, and were conservatively designated as Group A. The remaining lower risk digs were designated as Group B.

The Group A anomalies were concentrated in two areas, as shown in Figures 7 and 8.

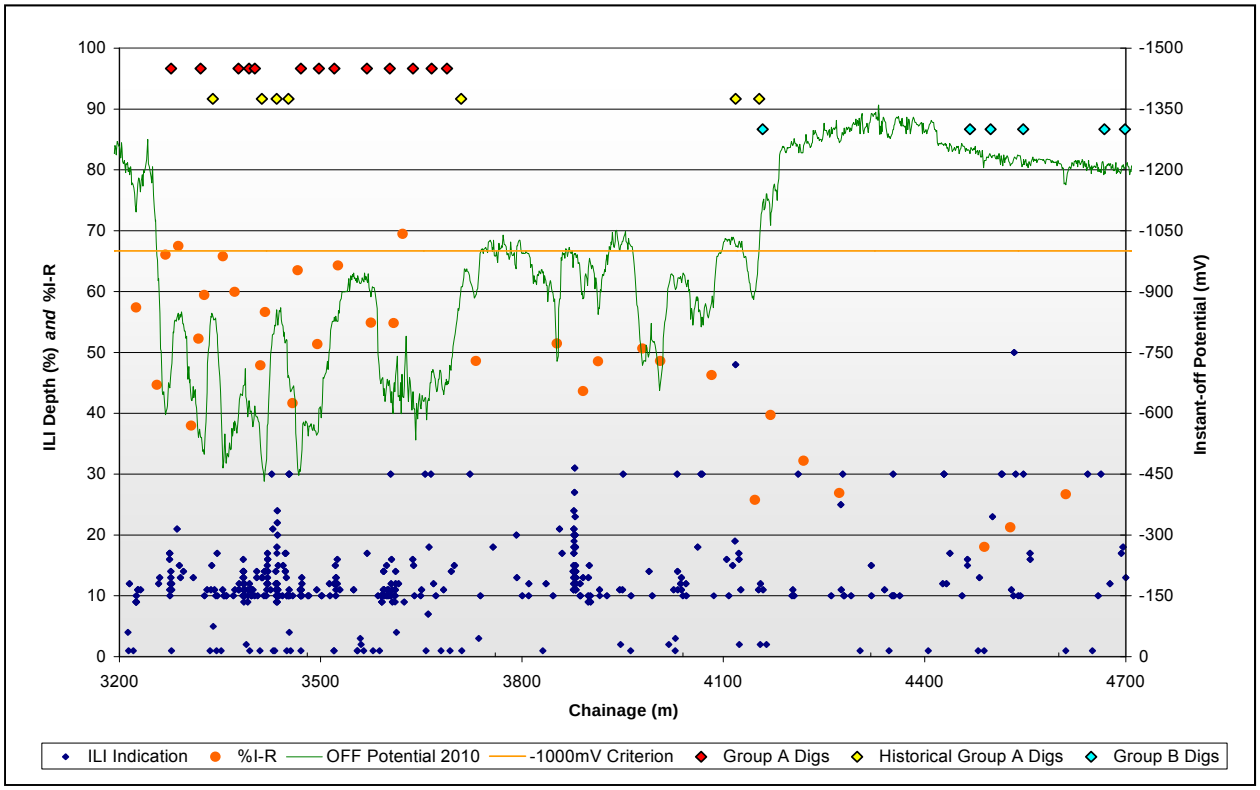

Figure 7: Ch. 3200 m to 4700 m. Overview of Proposed Digs vs. ILI/CIPS/DCVG Data

The digs in group A shown in Figure 7, are concentrated in the area between chainages 3250 m and 4200 m, with protection levels as low as -450 mV_{CSE} and calculated %I-R exceeding 60%. The remaining digs, prioritized as group B, are located in an area where the pipe is fully protected.

---

(2) Even well protected pipes displaying average rates of corrosion less than 1mpy, may result in up to 25% pit depth after more than 44 years.

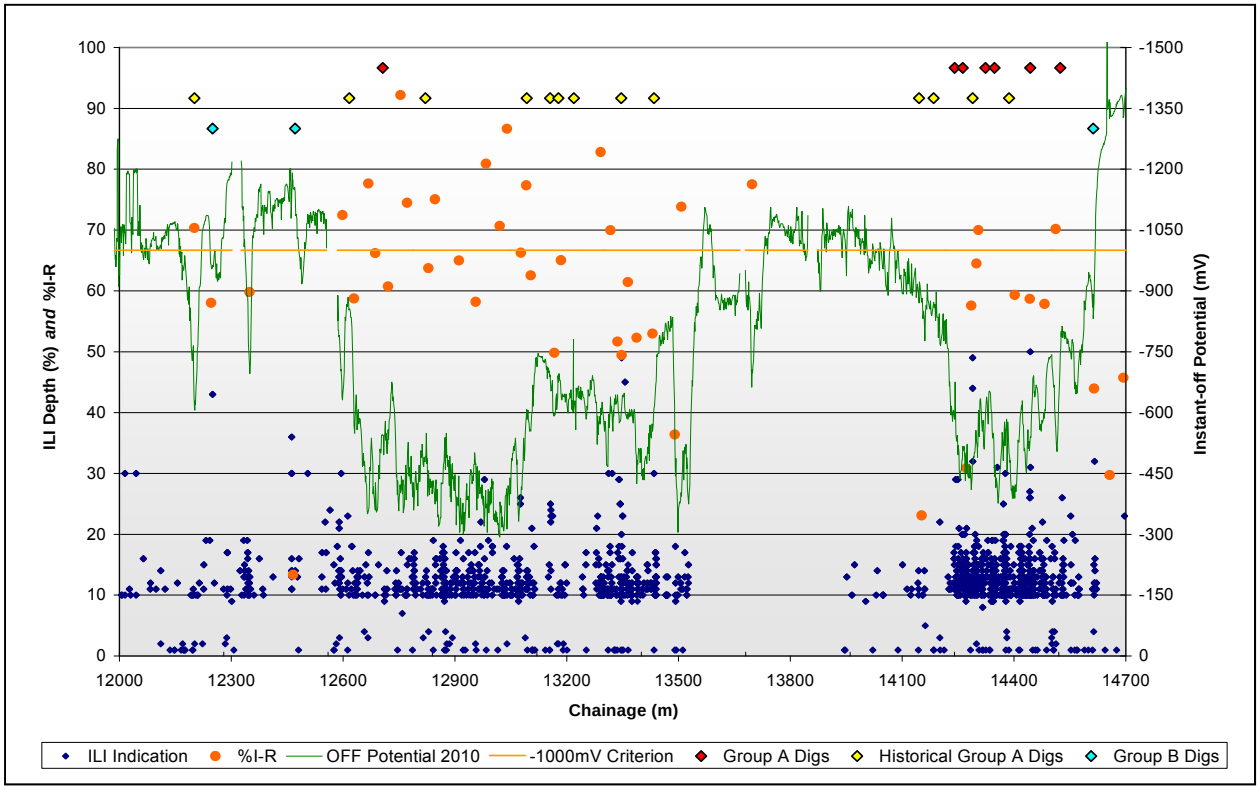

Figure 8: Ch. 12000 m to 14700 m. Overview of Proposed Digs vs. ILI/CIPS/DCVG Data

Figure 8 shows the second section with extensive sub-criterion potentials. Note that digs chosen as 'most-at-risk' (group A), using the ECDA type analysis, also typically coincide with higher concentrations of ILI anomalies.

A total of 37 digs, prioritized as "No Action Required" or "Suitable for Monitoring", were included in group B and subsequently removed from the immediate priority list. The remaining 25 digs, including their ECDA prioritization, were to be ranked based on the ILI data and the risk factor for the specific location.

The lesson: ILI and ECDA may be used not only alternatively, as indicated in NACE Standard SP0210-2010[7] "Pipe External Corrosion Confirmatory Direct Assessment", but they may also be used interactively to optimize each individual process.

THE "WISER" YEARS. DID WE SOLVE ALL THE PROBLEMS?

The answer is a definitive NO!

Conducting close interval potential surveys on bonded pipelines along common rights-of-way makes assessing the protection level of each pipeline extremely difficult. Furthermore, a coating holiday on one of the bonded pipelines would also be "seen" on the other lines. As such, improved survey procedures and new data processing methods must be developed to maintain the accuracy of the indirect inspection tools under these conditions.

How to deal with an indication identified along a section of pipe having a concrete coating remains a problem. Should the coating be removed to allow for a direct examination? Should the direct examination only be extended to confirm that the weld is also concrete coated? Should the section be removed from the ECDA segment and assessed separately, as a low risk section due to the high pH of the concrete?

The NACE Standard SP0502-2010 cannot provide answers to all questions and it is the role of the NACE papers and presentations to ensure the continuous improvement of the ECDA process, as required in Paragraph 6.8 of the Standard.

CONCLUSIONS

Several landmarks from our ECDA experiences were presented to emphasize the continuous improvement of the ECDA process, during more than ten years of application.

Selecting the ECDA regions may have a significant influence on the final number of digs and ultimately on the cost of the project. The best way to select the "right" number of regions is to assess the pre-assessment data in terms of risk of corrosion and accuracy of indirect inspection tools. Should a region have a significantly higher risk of corrosion or should the indirect inspection tools become "less reliable", a new region would typically be required.

Even the best survey practices do not apply under all field conditions. Under severe variations in soil resistivity, the normal practice of calculating the %IR by measuring the gradient to remote earth at the indication and interpolating pipe-to-soil potentials measured to remote earth at adjacent test posts could result in significant errors. Under AC interference, the practice of interrupting anode banks shall be reconsidered, to avoid errors due to rectification of AC voltages. Finally, special attention shall be given to equipment limitations in terms of measurement ranges to avoid "clipped" potentials.

The sound engineering practice beyond the NACE Standard SP0502-2010 facilitates using the ECDA approach in other integrity assessments.

REFERENCES

1. NACE Standard Recommended Practice SP0502-2010, "Pipeline External Corrosion Direct Assessment Methodology" (Houston, TX: NACE, 2010)

2. NACE Standard Recommended Practice RP0502-2002, "Pipeline External Corrosion Direct Assessment Methodology" (Houston, TX: NACE, 2002).

3. S. M. Segall, R. A. Gummow, R. G. Reid, "Ensuring the Accuracy of Indirect Inspections Data in the ECDA Process", CORROSION 2010, Paper No. 10061 (San Antonio, TX: NACE 2010).

4. S. M. Segall, R. A. Gummow, J. Shore, "Interpretation of Indirect Inspection Data in the ECDA Process", CORROSION 2011, Paper No. 11128 (Houston, TX: NACE, 2011).

5. S. M. Segall, R. A. Gummow, J. Shore, "Challenges in Analyzing ECDA Indirect Inspection Data", CORROSION 2014, Paper No. C2014-3815 (San Antonio, TX: NACE 2014).

6. S. M. Segall, R. A. Gummow, D. Fingas, J. Shore, "Use of ECDA Approach in Prioritization of ILI Anomalies", CORROSION 2012, Paper No. C-2012-0001231 (Salt Lake City, UT: NACE 2012).

7. NACE Standard Recommended Practice SP0210-2010, "Pipe External Corrosion Confirmatory Direct Assessment" (Houston, TX: NACE, 2010).