ENERGY CONNECTIONS CANADA

An Alliance for Energy Pipeline Innovation

Guidance for Managing Near-neutral pH Stress Corrosion Cracking

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https://energyconnectionscanada.com/

DISCLAIMER OF LIABILITY

In June 2023, the former Canadian Energy Pipeline Association (CEPA) Foundation rebranded to ECC. Among current ECC members are previous CEPA pipeline operators involved with the development of the *CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion*.

The mission of ECC is to mobilize the Canadian energy pipeline industry to influence an evolving energy sector and to achieve excellence in all aspects of industry performance: safety, sustainability, integrity, efficiency, and learning. The publication of this Guidance document is ECC's contribution to the safe pipeline delivery of energy products to benefit Canadians and the world.

Use of the Guidance document described herein is wholly voluntary. The practices described are not to be considered industry standards and no representation as such is made. It is the responsibility of each operator, or other users of this Guidance document, to implement practices regarding SCC that suit their specific pipelines, needs, operating conditions, and location.

Information concerning near-neutral pH SCC continues to grow and develop and, as such, this Guidance document is revised from time to time. For that reason, users are cautioned to confer with ECC to determine that they have the most recent edition of this document.

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The ECC Guidance document is intended to be considered as a whole, and users are cautioned to avoid the use of individual sections without regard for the entire document.

Acknowledgements

The update of the former *CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion Cracking* (3rd edition in 2015) into this 2025 edition, now a Guidance document, has been supported by the following operating companies within Energy Connections Canada:

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- Husky Midstream
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Contents

Executive Summary

This 2025 edition, *Guidance for Managing Near-neutral pH Stress Corrosion Cracking*, retains the framework of the SCC Management Program captured in the third edition published in 2015 by then Canadian Energy Pipeline Association. The SCC Management Program comprises nine steps encompassing three main aspects:

- Susceptibility assessment,
- Condition assessment and mitigation, and
- Condition monitoring.

This Guidance, with an expanded section on circumferential SCC, reflects updated research and practices by the pipeline industry in general and by member companies in particular for the management of near-neutral pH SCC on their gas and liquid pipeline systems. Some practices are common among operators; others are different.

Over the last decade, substantive progress has been made to improve the understanding of this threat to pipeline integrity. At the same time, significant advancements of in-line inspection technologies have enabled a proactive approach in detecting this threat that has been observed in more pipeline systems including pipelines of smaller diameters.

This Guidance document captures current knowledge and reflects practices in the industry and among operators within Energy Connections Canda. The dynamic nature of this threat necessitates active monitoring and as-needed changes in practices by each operator when and where warranted.

Glossary of Terms

TERM	DEFINITION
AMPP	Association for Materials Protection and Performance (which was created in 2021 when NACE International merged with SSPC or The Society for Protective Coatings)
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing of Materials
Cathodic protection	A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.
CEPA	Canadian Energy Pipeline Association (ceased operations on December 31, 2021)
CER	Canada Energy Regulator
Class location	A geographical area classified according to its population density and other characteristics that are considered when a pipeline is designed and pressure tested.
Coal tar	A hot-applied external coating made with coal tar pitch.
Coating disbondment	The loss of adhesion between a protective coating and the pipe substrate.
Colony	An area of stress corrosion cracks occurring in groups of a few to thousands of cracks within a relatively confined area.
Compressive stress	Stress that compresses or tends to shorten the material.
CORLAS™	Software package for Corrosion-Life Assessment of Piping and Pressure Vessels used to evaluate the safety factor of a specific defect involving corrosion and cracking.
Corrosion	Metal loss by chemical or electro-chemical dissolution that occurs because of the interaction of the metal (steel) with its environment.
CP	Cathodic protection
Crack	Very narrow, elongated defect caused by mechanical splitting into two parts. [Source: API RP 1176]
Critical flaw size	The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.
CSA	Canadian Standards Association
Defect	A physically examined anomaly with dimensions or characteristics that exceed acceptable limits. [Source: API Standard 1163]
Double submerged arc weld (DSAW)	A method of welding the long seam of a pipe in which the seam is submerged under a solid flux while being welded from both the internal and external surfaces of the pipe.
Elastic-plastic fracture mechanics	The consideration of both elastic and plastic deformation to predict the fracture behaviour of materials.
Electric resistance welding (ERW)	A welding process used in the manufacturing of pipe. [Source: API Std 1163]

TERM	DEFINITION
Electromagnetic acoustic transducer (EMAT)	A type of transducer that generates ultrasound in steel pipe without a liquid couplant using magnets and coils for inspection of the pipe. [Source: API Std 1163]
Engineering assessment (EA)	A documented assessment of the effect of relevant variables upon fitness for service or integrity of a pipeline system, using engineering principles, conducted by, or under the direct supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed. [Source: CSA Z662:23]
Environmentally assisted cracking (EAC)	Corrosive attack of the pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking. EAC includes but is not limited to hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide stress cracking (SSC), or stress corrosion cracking (SCC). [Source: API RP 1176]
Fatigue	The phenomenon leading to fracture of a material under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material.
Fracture mechanics	A quantitative analysis for evaluating structural reliability in terms of applied stress, crack length, and geometry.
Fracture toughness	Resistance of a material to fail from the extension of a crack [Source: API RP 1176]
Fusion-bonded epoxy (FBE) coating	Polymer coating that is chemically cured in place by heating. [Source: API RP 1176]
Girth weld	A complete circumferential butt weld joining pipe or components. [Source: API Std 1163]
High-pH SCC	A form of SCC on underground pipelines in which the crack growth or crack path is between the grains in the metal rather than through the grains of the metal. The cracks are typically branched and associated with an alkaline electrolyte (pH greater than 9.3). Also referred to as classical or intergranular SCC.
Hoop stress	The stress in the wall of a pipe or component that is produced by the pressure of the fluid in the piping, any external hydrostatic pressure, or both, and that acts in the circumferential direction. [Source: CSA Z662:23]
Hydrostatic test / Hydrotest	Pressure testing a pipeline by filling it with water and pressurizing it until the nominal hoop stresses in the pipe reaches a specified value.
Integrity Management Program (IMP)	A documented program that specifies defines the practices used by the operating company to ensure the safe, environmentally responsible, and reliable service of a pipeline system. [Source: CSA Z662:23]
In-line inspection (ILI)	Inspection of a pipeline from the interior of the pipe using an inspection tool (also called intelligent or smart pigging and includes tethered and self-propelled inspection tools). [Source: API RP 1176]
Interacting	Describes cracks whose tips are close enough together that the stress fields in front of the propagating crack tip overlap.
Interlinking	Describes cracks whose tips are close enough that the stress fields in front of the propagating cracks are relieved, and they physically join to eventually form one crack.

TERM	DEFINITION
J or J-integral	A factor used to characterize the fracture toughness of a material having appreciable plasticity before fracture.
Launcher	A device used to insert an ILI tool into a pressurized pipeline; may be referred to as a pig trap or scraper trap. [Source: API Std 1163]
Longitudinal stress	The stress at any point on the pipe cross-section acting in the longitudinal direction. (Note: Longitudinal stress includes the effects of both bending moments and axial forces). [Source: CSA Z662:23]
Magnetic flux leakage (MFL)	Type of ILI technology in which a magnetic field is induced in the pipe wall between two poles of a magnet to detect, classify, and characterize anomalies. [Source: API RP 1176]
Magnetic particle inspection (MPI)	A non-destructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field.
Maximum operating pressure (MOP)	The maximum pressure, not exceeding the design pressure, at which piping is qualified to be operated. [Source: CSA Z662:23]
MTR	Mill test records
NACE International	National Association of Corrosion Engineers International (which was merged with SSPC or The Society for Protective Coatings in 2021 to form the Association for Materials Protection and Performance (AMPP))
NDT or NDE	Non-destructive Testing or non-destructive examination. The inspection of piping to reveal imperfections using radiographic, ultrasonic, or other methods that do not involve disturbance, stressing or breaking of the material.
Near-neutral pH SCC	A form of SCC on underground pipelines associated with a near-neutral pH electrolyte in which the crack growth or crack path is through or across the grains of a metal. Typically, this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as transgranular SCC.
NEB	National Energy Board (which became the Canada Energy Regulator in 2019)
Nominal wall thickness	The specified wall thickness of the pipe purchased. [Source: CSA Z662:23]
Operating company	The individual, partnership, corporation, or other entity that operates a pipeline system. [Source: CSA Z662:23]
Outside diameter	The specified outside diameter (OD) of the pipe, excluding the manufacturing tolerance provided in the applicable pipe specification or standard. [Source: CSA Z662:23]
PAFFC	Software package for Pipe Axial Flow Failure Criterion to determine the failure conditions associated with a single external axial flaw in a pipeline.
pH	Measure of the acidity or alkalinity of a substance or solution, with a value of seven defined as neutral and a higher value than seven being alkaline.
Pipe segment	A length of pipe bounded by changes in pipeline attributes which, in the operator's experience, justify a change in the probability of SCC compared to adjacent segments. A pipeline segment can vary in length from a few joints to many kilometres.
Pipeline	Those items through which oil or gas fluids are conveyed, including pipe, components, and any appurtenances attached thereto, up to and including the isolating valves used at stations and other facilities. [Source: CSA Z662:23]

TERM	DEFINITION
Pipeline system	Pipelines, stations, and other facilities required for the measurement, processing, storage, gathering, transportation, and distribution of oil and gas industry fluids. [Source: CSA Z662:23]
Pipe-to-soil potential	Electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte. [Source: API RP 1176]
Plastic collapse	Failure that occurs by ductile fracture and is governed by material strength properties. [Source: API RP 1176]
PRCI	Pipeline Research Council International
RSTRENG	A computer program designed to calculate the pressure-carrying capacity of corroded pipe.
R-ratio or R-value	A ratio of the minimum to maximum stress (as a measure of the magnitude of a pressure cycle). [Source: API RP 1176]
Rainflow counting	Cycle counting is used to summarize irregular load-versus-time histories by providing the number of times cycles of various sizes occur. [Source: API RP 1183]
Receiver	A pipeline facility used for removing a pig from a pressurized pipeline; may be referred to as trap or pig trap or scraper trap. [Source: API Std 1163]
Residual stress	Stress present in an object in the absence of any external loading, typically resulting from manufacturing or construction processes. [Source: API RP 1176]
Rupture	Failure of the pipe in a manner that involves unstable extension or propagation of a fracture, resulting in a release of pipe contents and usually an inability to maintain pressure while in operation. [Source: API RP 1176]
SCC MP	Stress corrosion cracking management program
Specified minimum yield strength (SMYS)	The minimum yield strength prescribed by the specification or standard to which a material is manufactured. [Source: CSA Z662:23]
SSPC	Steel Structures Painting Council (which was rebranded to The Society for Protective Coatings and then merged with NACE International in 2021 to form the Association for Materials Protection and Performance (AMPP))
Stress concentration (raiser)	A discontinuity, such as a crack, gouge, notch, or geometry change that causes an intensification of the local stress.
Stress corrosion cracking (SCC)	Form of cracking produced by the combined application of tensile stress (residual or applied), a corrosive environment, and steel that is susceptible to SCC. [Source: API RP 1176]
Stress intensity factor (K_I)	A factor used to describe the stress intensification of applied stress at the tip of a crack of known size and shape.
Tensile stress	Stress that tends to elongate the material.
Tenting	A tent-shaped void formed along the seam weld of a pipeline where the external coating bridges from the top of the weld to the pipe.
Terrain conditions	Collective term used to describe soil type, drainage, and topography.
Transverse field magnetic flux leakage (TFMFL)	MFL tool where the magnets and sensors have been rotated 90 degrees to induce a magnetic field along the circumference of the pipe.
TSB	Transportation Safety Board of Canada

TERM	DEFINITION
Ultimate tensile strength	The stress obtained by dividing the maximum load attained in a conventional tensile test by the original cross-sectional area of the test specimen. [Source: CSA Z662:23]
Undercoating electrolyte	Soil or liquid between a disbonded coating and a buried or submerged pipe.
UT	Ultrasonic Testing
Valve section	A section of a pipeline isolated by valves.
Yield strength	The stress at which a material exhibits the specified limiting offset or specified total elongation under load in a tensile test as prescribed by the specification or standard to which the material is manufactured. [Source: CSA Z662:23]

1. Introduction

1.1 Background

Thirty years ago, in 1996, the National Energy Board (now Canada Energy Regulator) published a report of its inquiry concerning pipeline stress corrosion cracking (SCC) in Canada, which focussed on the near-neutral pH (NN-pH) type that caused a string of failures among oil and gas pipeline operators. Among the list of issues, the inquiry set out to understand the extent and severity of NN-pH SCC, to gauge industry knowledge of this type of SCC, and to assess industry experience in the prevention, detection, and management of the serious emerging pipeline integrity threat.

Out of the recommendations from the Report of the Inquiry[1] was a request by the regulator for then Canadian Energy Pipeline Association (CEPA), comprised of major oil and gas midstream operators, to complete its SCC Recommended Practices Manual. The Recommended Practices were developed to support operators in the development and implementation of an SCC management program as required by the regulator shortly after the conclusion of the inquiry. The original SCC Recommended Practices were published in 1997. The second edition (issued in 2007) and the third edition (issued in 2015) provided updated scientific and engineering knowledge based on the latest SCC research and reflected updated practices based on Canadian operator experiences.

For many, if not all, Canadian pipeline operators, SCC management has since been integrated into a broader pipeline integrity management program[2] addressing all relevant hazards/threats within their safety and loss management system.

1.2 Scope

The SCC Guidance document deals specifically with external NN-pH SCC and consider both axial and circumferential cracking. They do not address high-pH SCC even though many program activities for high-pH SCC management are similar.

The aim of this Guidance document is to capture updated research and industry practices relevant to the SCC Management Program (SCC MP) and to highlight some common or different practices among several Canadian midstream oil and gas pipeline operators for the management of NN-pH SCC, with the following goals:

- Protecting the safety of the public and pipeline company employees,
- Protecting the environment, private and company property, and
- Maintaining the reliable and economical operation of the Canadian pipeline system.

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[1] Report MH-2-95 (National Energy Board, 1996), which can be obtained from the CER library, provides foundational knowledge of both NN-pH and high-pH SCC from which subsequent research builds on to address knowledge gaps.

[2] Canada Energy Regulator's *Onshore Pipeline Regulations*, which came into force in June 1999, require federally regulated pipeline companies to develop, implement, and maintain an integrity management program (IMP). The Canadian Standards Association's *CSA Z662* Standard for oil and gas pipeline systems, which has been adopted within federal and provincial pipeline regulations, has specified a requirement for an IMP since the 2011 edition.

2. NN-pH SCC Overview

2.1 Mechanism of NN-pH SCC Initiation and Growth

Like high-pH SCC, NN-pH SCC is a type of environmentally assisted cracking (EAC) that typically occurs on the external pipeline surface when the pipe is exposed to a potent environment in combination with a sufficiently high tensile stress. SCC initiating on the pipeline surface can grow in both depth and length directions. Cracks always propagate in a direction perpendicular to the direction of the principal stress, typically the hoop stress, resulting in crack alignment along the longitudinal axis of the pipeline. When the longitudinal tensile stresses reach a certain level, circumferential SCC (Section 3.4) may occur on a pipeline exposed to a potent environment.

At the time of the NEB SCC Inquiry, NN-pH SCC was thought to initiate by a corrosion fatigue mechanism or by a less likely anodic dissolution mechanism, and then to propagate by a hydrogen embrittlement mechanism driven by cyclic loading (Beavers & Harle, 1996). Subsequent research led to a proposed crack growth rate equation that is a function of stress intensity factor range, maximum stress intensity factor, loading frequency, and soil corrosivity (Chen, Kania, Worthingham, & Kariyawasam, 2008).

Further research sponsored by the Pipeline Research Council International (PRCI) resulted in a report that identified two governing processes for NN-pH SCC: dissolution growth process for crack initiation and early-stage crack growth followed by a hydrogen-facilitated fatigue growth after crack initiation and dormancy (Chen, 2016). The processes are shown in Figure 1.[3]

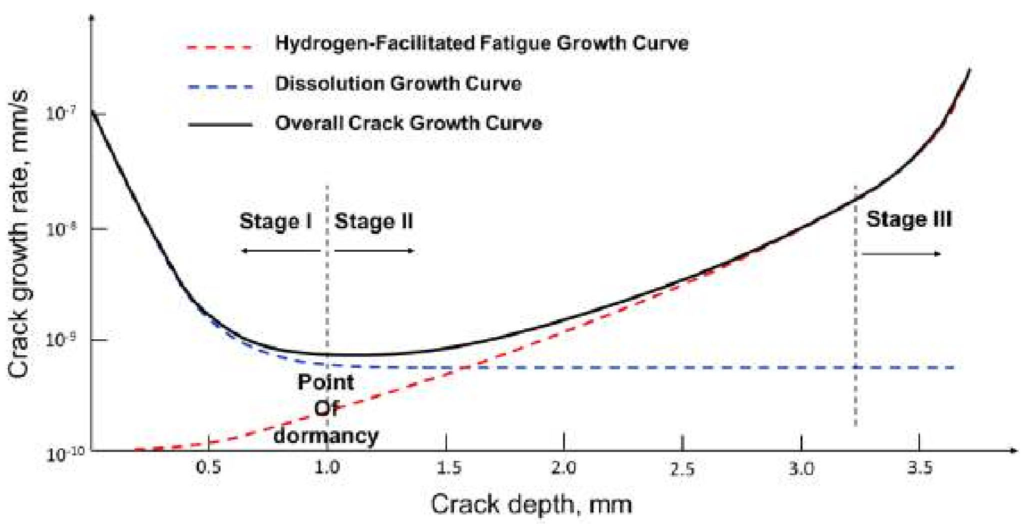

Figure 1. Processes governing crack initiation and growth in pipeline steels exposed to near neutral pH environments (reproduced with permission from PRCI)

[3] Based on current understanding, cracks initiate in Stage I from localized corrosion at the pipe surface and grow at a decreasing rate. During Stage II, NN-pH SCC grows at an increasing rate due to a hydrogen-enhanced process. Finally, in Stage III, crack growth is accelerated until failure.

Previous experiments[4] had indicated that cyclic stresses appeared to play a more important role in NN-pH SCC propagation than significant applied stresses. The PRCI study validated the earlier finding and investigated the effects of three different types of pressure fluctuations: underload, mean load, and overload. API RP 1176[5] discusses these three categories and the impact of variable loading conditions on crack growth.

Finally, in a recent microstructural study[6] of pipe removed from service containing axial NN-pH SCC (A-SCC) and circumferential SCC (C-SCC), the authors noted the examined SCC features propagated without high stress intensity and observed the crack growth was intergranular (which was contrary to conventional understanding), followed by corrosion via a likely anodic dissolution mechanism into the adjacent grains in the open crack.

In summary, while it appears that the complex mechanism of NN-pH SCC initiation and growth has yet to be fully understood, the focus of this Guidance document is on the practical management of NN-pH SCC features once they have been observed.

2.2 SCC Trends

In the last decade, pipeline failures caused by A-SCC and C-SCC in Canada have been infrequent based on publicized investigation reports.[7] However, it is also possible the number of reported SCC incidents has appeared low due to such events being assigned with a generic “cracking” failure cause by regulatory authorities without specifying the exact cracking mechanism.

What seems to be a clear trend in recent years has been an increase of observed C-SCC among numerous pipeline operators in different parts of the world, including among ECC operators.

3. SCC Management Program

3.1 Introduction to the SCC MP

Each pipeline system is unique in its design, construction, and operating and maintenance history. While the steps of the SCC MP are common among ECC pipeline operators, each company may implement different program activities based on its experience with managing SCC within a risk-based regulatory framework in Canada. The variation in practices, including the classification of SCC severity, is reflected in the responses by six ECC operators to a survey questionnaire covering different aspects of their SCC MP.

The SCC MP structure applies equally to axial and circumferential cracking, but specific issues associated with C-SCC are discussed separately in Section 3.4.

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[4] Paper No. IPC1998-2049 (Wilmott & Sutherby, 1998)
[5] API RP 1176 *Recommended Practice for Assessment and Management of Cracking in Pipelines* (which was first published in 2016, reaffirmed in 2024, and is currently undergoing review for the next edition)
[6] Paper No. IPC2024-133924 (Long, Zhang, Persaud, & Daymond, 2024)
[7] The most recent SCC failure on a federally regulated pipeline investigated by the Transportation Safety Board of Canada occurred in 2018 (Transportation Safety Board of Canada, 2020).

3.2 SCC MP Flow Chart

From the previous edition, the three basic components of an SCC MP are captured in Figure 2. SCC Management Program Flow Chartare susceptibility assessment (Steps 1 to 3, colour coded blue), characterization and mitigation of SCC (Steps 4 to 7, colour coded green), and condition monitoring (Step 8 and 9, colour coded purple).

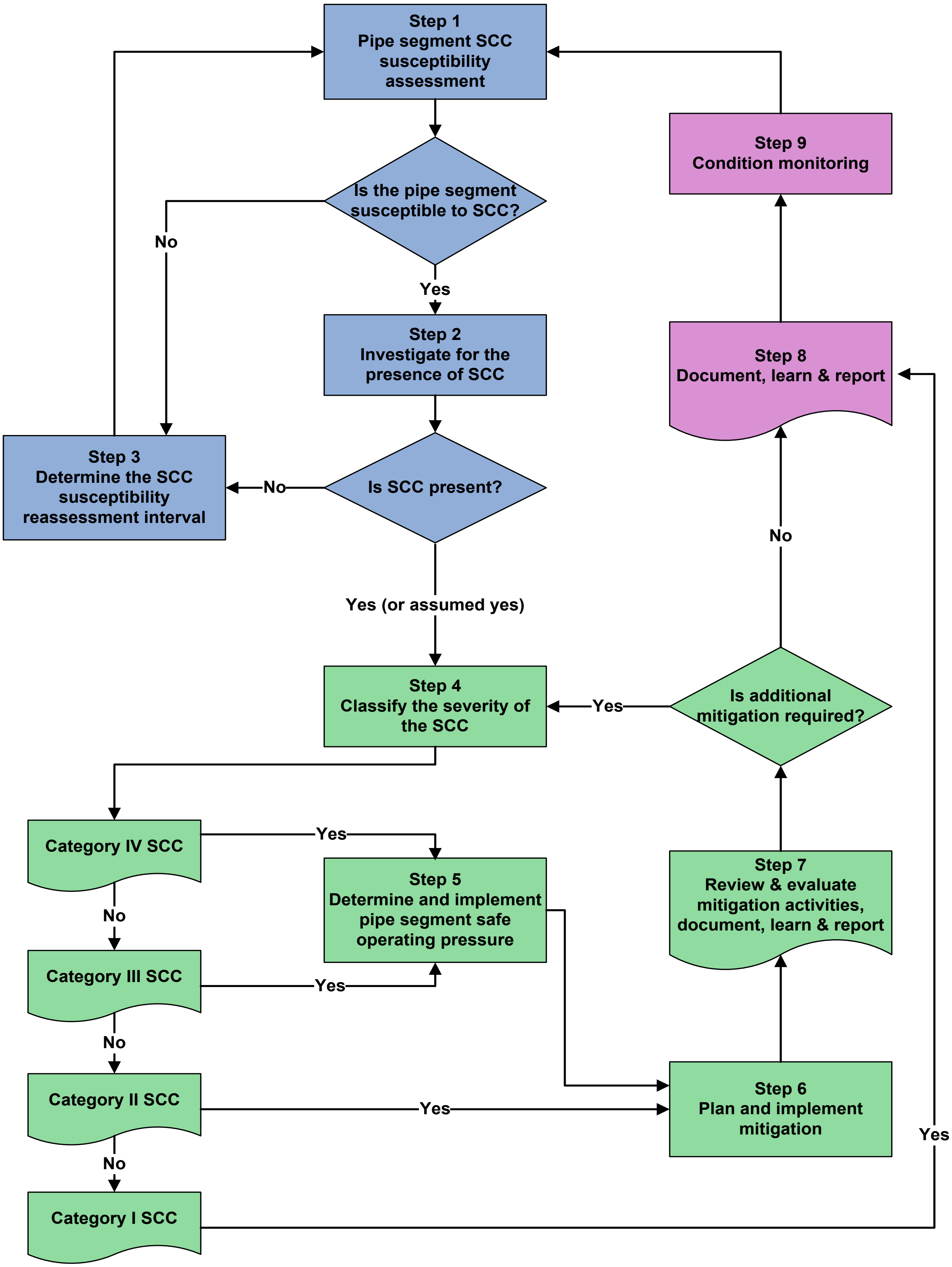

Figure 2. SCC Management Program Flow Chart

3.3 Axial SCC

3.3.1 Pipe Segment Susceptibility Assessment

An initial susceptibility assessment is required on every pipe segment (typically from launcher to receiver for a short pipeline or from valve to valve for a longer pipeline) and should be repeated periodically if the segment were found to be non-susceptible.

Among the four broad categories of susceptibility conditions in Table 1, pipeline maintenance data provide the strongest evidence of SCC susceptibility. Without such data, pipe body and field joint coating type, operating stress level and pressure cycling, and age[8] have been identified as the more important conditions used by ECC operators to screen susceptible pipeline segments.

Table 1: SCC Susceptibility Conditions

Pipeline Attributes	**Operating Conditions**	**Environmental Conditions**	**Pipeline Maintenance Data**
Coating type	Stress level	Terrain	In-line inspection (ILI) results
Age	Pressure cycling	Soil type	Failure history
Original construction season	Temperature	Soil carbon dioxide level	Excavation records
	Distance downstream of compressor or pump station	Drainage characteristics	Coating condition
	Cathodic protection level and shielding	Land use	
	Product type		

In 2013, the PRCI published a document to "define operating conditions in which no SCC exists" and concluded that the only condition identified was pipe coated with fusion bonded epoxy (FBE) (Fessler, Batte, & Been, 2013). SCC has also not been documented on pipe body coated with extruded polyethylene or pipe joints coated with epoxy or epoxy urethane. SCC is only possible if the coating disbonds from the pipe, allows an ingress of ground water (electrolyte) to be trapped and contacts the steel surface, and shields the electrolyte and steel from the cathodic protection (CP) system. To date, SCC has been found beneath field applied polyethylene tape (Figure 3), asphalt enamel, coal tar, and girth weld shrink sleeves.

[8] Pipeline age may be a proxy of coating condition. In an analysis of pipeline ruptures on federally regulated pipelines in Canada from 1984 to 2003 (Paper No. IPC04-0272 (Jeglic, 2004)), the author indicated one pipeline failed during the 13th year of operation. One ECC member indicated NN-pH SCC has been observed on a pipeline operating in approximately the same timeframe.

Figure 3. Disbonded polyethylene tape coated pipe

Industry experience has shown that a disbonded coating, by itself, may not lead to the initiation of SCC. As noted in Section 2.1, other factors such as hydrogen, cyclic pressure, and local stress level can dictate whether NN-pH SCC would form at specific pipe joints at a certain time.

3.3.2 Investigate the Presence of SCC

If a pipeline segment has been assessed to be susceptible to NN-pH SCC in Step 1, it should be inspected for the presence of cracking in this Step 2 via excavations (digs) or ILI technology.

Digs can be opportunistic or exploratory in nature. Opportunistic digs occur when other types of reported features, such as corrosion or dent anomalies, are targeted and those locations can be used to confirm the presence or absence of SCC. However, since deeper corrosion anomalies are typically selected to avoid a leak or rupture, these sites may not necessarily be where SCC could be observed. With dents, cracking has been observed but such cracking may be associated with corrosion fatigue and may not confirm the presence of SCC along the rest of a susceptible pipe segment. Appendix C provides guidance on data collection at dig sites to support ongoing susceptibility assessment.

Dig sites have also been selected using models developed based on the SCC Direct Assessment Methodology (NACE, 2015) that integrate data beyond the historical soil models. While there has been some success in finding SCC via this method, such models are not currently used broadly among ECC operators. A challenge with this method is establishing enough digs to confirm the absence of SCC in a segment.[9]

[9] Published in 2015, PRCI's "Procedure for determining the number of excavations to validate SCCDA" (PRCI, 2015) proposed the use of Bayesian updating (i.e., where new information is used to update prior predictions of the occurrence of an event) to establish the number of digs required to achieve a certain confidence level.

Alternatively, for a piggable pipeline segment, ILI technology can be more effective and thorough in confirming the presence or absence of SCC on a susceptible pipe segment. Crack ILI technology has evolved and advanced significantly since the NEB SCC Inquiry such that it has been accepted as a reliable integrity assessment method. API RP 1176 discusses principles of different ILI technologies and their capabilities and limitations. Appendix A of this Guidance document provides several published references by ILI service providers and pipeline operators demonstrating tool performance.

Based on the current tool performance, ECC operators have relied on various crack inspection technologies to inspect susceptible pipe segments, followed by validation digs, within one or two years of such assessment as driven by corporate risk requirements.

3.3.3 Determine the SCC Susceptibility Reassessment Interval

For pipe segments either deemed to be non-susceptible or for which no SCC was found from digs or ILI, no further activities would be required until the next susceptibility assessment. To determine the timing of the next SCC susceptibility assessment for Step 3 of the SCC MP process, the following points should be considered:

- The possibility that one or more conditions in Table *1* may change resulting in an increase in SCC susceptibility,
- The probability of detection for the inspection program used to investigate for the presence of SCC, and
- A change in the consequence of SCC failure within the pipeline segment.

The previous edition recommended a maximum reassessment interval of ten years. Among the ECC operators surveyed, there is a wide spectrum, ranging from no set maximum to a fixed seven-year maximum interval to an interval determined from an engineering or risk assessment.

3.3.4 Classify the Severity of SCC

If cracks were found during the investigation phase (Step 2), the SCC features can be classified according to the four severity categories in Table 2. The SCC severity categories provide a measure of the condition of a pipe segment, dictate whether a temporary pressure restriction is necessary (Step 5), and define the type and timing of mitigation (Step 6).

Table 2: SCC Severity Categories

Category	Definition	Description
I	$P_{F,SCC} \geq 110\% \times MOP \times SF$	A failure pressure greater than or equal to 110% of the product of the MOP and a company defined safety factor (SF). The failure pressure for Category I SCC typically exceeds 110% of SMYS.
II	$110\% \times MOP \times SF > P_{F,SCC} \geq MOP \times SF$	A failure pressure less than 110% of the product of the MOP and a company defined safety factor, but greater than or equal to the product of the MOP and a company defined safety factor.
III	$MOP \times SF > P_{F,SCC} > MOP$	A failure pressure less than the product of the MOP and a company defined safety factor but greater than the MOP.
IV	$P_{F,SCC} \leq MOP$	A failure pressure equal to or less than MOP.

The categories align partially with those captured in ASME B31.8S;[10] the safety factors are prescribed in that ASME standard and the criterion used for Category III and Category IV is 110% of the maximum allowable operating pressure (applicable for U.S. gas pipelines). However, CSA Z662:23 does not explicitly define such categories as all cracks are considered defects unless demonstrated to be acceptable via an engineering assessment. Each operating company needs to justify the established safety factor used for crack assessment of any pipeline, based on the MOP or a lower established operating pressure.

Among ECC operators, there is a range of practices, as follows:

- The severity categories are not currently leveraged by all operating companies.
- Estimated remaining life and reliability threshold drive response and timing of response.
- A crack depth greater than 70% of nominal wall thickness is prioritized over the failure pressure criterion.
- Severity Category III and Category IV are used to drive expedited response, including any necessary temporary pressure restriction.
- If used, the defined safety factor is based on a combination of design factor and class location factor.

Regardless of whether the severity categories are being used or not, fully or partially, the failure pressure of an SCC feature needs to be determined. The estimated burst pressure of a pipe with SCC is based on the chosen failure stress model, crack flaw dimensions, and pipe material properties.

3.3.4.1 Failure Stress Models

CSA Z662:23 references Annex C of API RP 1176 for different methods used to determine the failure pressure of cracks and crack-like flaws. The first edition of API RP 1176 included the Battelle Model (Log-

[10] Table A-4.4-1 of ASME B31.8S-2022 (ASME, 2022)

secant), CorLAS™ Model, and API 579-1/ASME FFS-1.[11] It is anticipated that other methods, including PRCI MAT-8 Model,[12] will be included in the next edition. Each method was developed and correlated against burst tests and has inherent limitations and accuracy. For each pipeline assessment case, the appropriate method is to be used with the relevant input parameters.

For SCC features, ECC operators overwhelmingly use the CorLAS model for assessment. The CorLAS model[13] has been shown to be the most accurate with the least uncertainty among the models commonly used in the pipeline industry.

3.3.4.2 Crack Flaw Interaction

Flaw interaction rules influence the input value for the crack length. SCC interaction refers to the effect of the overlapping crack tip stress fields of two adjacent SCC features, even though visually the cracks may not appear to be connected. For interacting cracks, the total length encompassed by two (or more) SCC features should be used in the failure pressure calculation.

Interaction is assessed in both the circumferential and the axial directions as illustrated in Figure 4.

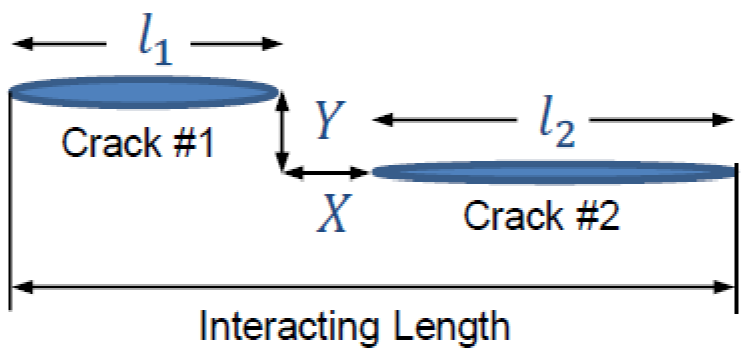

Figure 4. "CEPA Interaction Rules" (reproduced with permission from PRCI)

In the previous edition, two SCC features are deemed to be interacting in the circumferential direction if

$$Y \leq \frac{0.14(\ell_1 + \ell_2)}{2}$$

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[11] Part 9 of API 579-1/ASME FFS-1 (Fitness-for-Service standard) covers the requirements for the assessment of crack-like flaws.

[12] The MAT-8 Model is discussed in PRCI Catalog No. PR-460-134506-R01 (Anderson, Development of a modern assessment method for longitudinal seam weld cracks, 2015) and Catalog No. PR-460-134506-R02 (Anderson, 2017).

[13] For failure pressure estimation of SCC features, CorLAS has been shown to be more accurate than the API 579 Level II, Log-secant, and PAFFC methods. Refer to the following published works: CER's Report of the SCC Inquiry (National Energy Board, 1996), Paper No. IPC2010-31158 (Hosseini, Cronin, Kania, & Plumtree, 2010), Paper No. IPC2012-90236 (Fessler R. R., Batte, Rosca, & Boven, 2012), Paper No. IPC2014-33563 (Tandon, Gao, Krishnamurthy, Kariyawasam, & Kania, 2014), Paper No. IPC2018-78251 (Yan, Zhang, Kariyawasam, Pino, & Liu, 2018), and Paper 36 PPIM2021 (Hanna, Bubenik, Polasik, & McMahan, 2021).
While CorLAS may yield inaccurate or overly conservative predicted failure pressure for a crack or crack-like feature located on pipe with fracture toughness less than 5 ft-lbs (~ 7 J), a source document has not been found to explicitly limit the application of CorLAS for such scenario.

where Y is the circumferential distance between the two cracks of lengths ℓ_1 and ℓ_2. Two SCC features are deemed to be interacting in the axial direction if

$$X \leq \frac{0.25(\ell_1 + \ell_2)}{2}$$

where X is the axial spacing between the two SCC features. Both the axial and circumferential criteria must be met for the SCC features to be interacting. If either X or Y is greater than the calculated limit, the SCC features can be treated as individual features for failure pressure calculation purposes. When a third SCC feature is to be assessed adjacent to two SCC features already determined to be interacting, the non-interacting lengths of adjacent SCC features are to be used in the assessment.

In 2020, PRCI and CRES published results of "intelligent flaw interaction rules"[14] based on the principles of equivalent impact between multiple interacting cracks and a single dominant crack. The rules were developed using numerical analysis and evaluated through full-scale burst tests. The results demonstrated that the PRCI-CRES rules yielded more accurate and consistent failure pressure prediction of SCC colonies than the previous "CEPA interaction rules."[15]

Each pipeline operator can choose the appropriate interaction rules, including one of several from API 579, based on the objective of the assessment for a particular pipeline.

3.3.4.3 Material Properties

Pipe fracture toughness is an essential input parameter for crack assessment and is typically obtained indirectly via Charpy V-Notch (CVN) values. When original mill test records are unavailable to furnish the CVN value, pipe cut-out samples either from in-service failures or from integrity digs can be used to determine an appropriate CVN value. Absent of such source data, assumed values could be used but would lead to conservative (lower) predicted failure pressure for a crack or crack-like feature. An option is to establish the CVN value using samples from a similar pipe, as explained in a recent paper by an ECC member[16]. Alternatively, several published works have produced yield strength, tensile strength, and higher fracture toughness values for a range of material grades for different vintage pipes that may be suitable for a particular pipeline under assessment.[17]

3.3.5 Determine and Implement a Pipe Segment Safe Operating Pressure

Once the failure pressure of an SCC feature (or the lowest failure pressure among multiple SCC features) within a pipe segment has been calculated, this Step 5 of the SCC MP process evaluates if there is a need to reduce the operating pressure. Each pipeline operator should have documented procedures to guide decisions on the discovery of SCC features based on reported crack ILI results or based on observations

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[14] The PRCI-CRES SIA-1-5 interaction rules are documented in PRCI Catalog No. PR-350-144502-R02 (Wang B. , Liu, Wang, Chen, & Wang, 2020) and discussed in Paper No. IPC2020-9693 (Wang B. , Liu, Wang, Wang, & Rapp) and Paper No. IPC2020-9696 (Wang B. , Liu, Wang, Wang, & Rapp, 2020).

[15] "The CEPA interaction rules" were formulated by R.N. Parkins and P.M. Singh (Parkins & Singh, 1990).

[16] Paper No. IPC2024-133503 (Zhang, Xiang, Myden, & Riverol, 2024)

[17] Annex D of API RP 1176 provides yield and tensile strength values for a range of material grades. Paper No. IPC2022-86014 (Bagnoli, et al., 2022) and PPIM Paper 2023.85:03 (Limon, Madera, Coulter, George, & Krishnamurthy, 2023) provide fracture toughness values.

from excavated sites. Industry practices have used a pressure reduction value of "not greater than 80% of the recent operating pressure"[18] as a general guideline, but this criterion (or an alternative) needs to be specifically defined by each operator in accordance with corporate risk thresholds.

3.3.6 Plan and Implement Mitigation

Once every identified SCC feature has been assessed in Step 4, features meeting an operator's established acceptance criteria can be monitored, while those not meeting acceptance criteria need to be mitigated. Table 10.2 of CSA Z662:23 captures the allowable mitigation options for surface cracks, such as NN-pH SCC, which include grinding, repair sleeves, and pipe replacement. While not common, hydrostatic testing can also be used to cause any critical A-SCC features to fail in a controlled environment instead of such features possibly failing while the pipeline segment is in service.

For mitigation of A-SCC, ECC operators have repaired such features by grinding, applying steel containment sleeves or steel compression reinforcement sleeves, and replacing pipe.[19]

3.3.7 Review and Evaluate Mitigation Activities

For unmitigated A-SCC features remaining in a pipe segment that will be monitored, part of this Step 7 is to predict their fatigue life or remaining life and failure pressure into the future considering an appropriate growth rate. Either a deterministic or a probabilistic assessment can be used within the context of defect assessment. Among ECC operators, several exclusively use a deterministic approach while others use both approaches depending on the objective.

A deterministic approach is simpler and requires less effort to complete. Typically, the lower-bound values influencing a pipe's pressure-carrying capacity (e.g., material grade, yield strength, fracture toughness, wall thickness) are used, whereas upper-bound values influencing the applied load (e.g., operating pressure, sizing error, crack growth rate) are maximized. This approach has a net effect of lowering the pipe resistance to failure and driving a need to respond sooner, as multiple margins of safety are layered upon each other.

With a probabilistic approach, it is unnecessary to stack margin-of-safety layers. Instead, the uncertainty of all measured values is accounted for and the distribution of values on both the pipe capacity side and the load demand side generate upward of a million scenarios (as typically generated with a Monte Carlo analysis). This method requires more effort to complete and more knowledge of the distribution of values of the input parameters. However, the results tend to be less conservative and more representative than the deterministic analysis, which could either reduce the number of A-SCC features that need to be mitigated before a certain timeframe or push out the next assessment further into the future without reducing an operator's corporate safety or reliability target.

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[18] Commentary to Clause 10.10.1.4 of CSA Z662:23

[19] One ECC operator has evaluated the practicality of recoating shallow SCC features (up to 20% of the nominal wall thickness on gas pipelines with a minimum fracture toughness of 20 J) without first removing them by grinding. Refer to Paper No. IPC2022-87340) (Milligan, et al., 2022) for details.

Regardless of the approach, crack depth growth rate[20] needs to be accounted for in remaining life assessment. Table 3 tabulates a range of average growth rates that are mostly the same as those found in the previous edition. Each pipeline is unique, so a chosen or calculated crack growth rate should be justified, whether it lies within or outside the ranges based on field NDE and limited failure data.

Table 3. Range of Reported Average SCC Depth Growth Rates[21]

Method	Minimum			Maximum		
	mm/s	mm/yr	in./yr	mm/s	mm/yr	in./yr
Laboratory	0.2e-8	0.06	0.002	2.8e-8	0.88	0.035
Fractography (failures)	1.0e-8	0.3	0.012	2.0e-8	0.63	0.025
	1.0e-9	0.03	0.001	5.0e-9	0.16	0.006
Field nondestructive examination	1.0e-9	0.03	0.001	4.8e-9	0.15	0.006
In-line inspection	n/a			n/a		

Applying a chosen crack growth rate, a deterministic or probabilistic assessment can drive the timing of the next ILI and the need to mitigate any remaining A-SCC features prior to the next re-assessment.

3.3.8 Document, Learn, and Report

Documentation and retention of pipeline records are regulatory requirements and are important for Step 8 of the SCC MP process. Program activity decisions, including the rationale for any project deferral or cancellation, related to pipeline assessment, inspections, mitigation, and monitoring activities need to be documented to support compliance and due diligence, to demonstrate adequacy and effectiveness in risk reduction of the NN-pH SCC threat, and to enable continuous improvement through lessons learned from program activities.

The survey for the ECC operators included the following questions with a summary of collective responses[22]:

What aspects of the SCC management program have been found to be surprising or unexpected to date?

- Double-wrap polyethylene tape coating leads to the highest crack growth/failure rates for axial NN-pH SCC
- Coating degradation and subsequent SCC initiation can occur much sooner based on the onset of coating failure rather than on the age of a pipeline segment

[20] ECC members typically do not apply length growth rate for fatigue crack growth assessment. For determining ILI re-inspection interval, one ECC member uses a 100:1 length to depth ratio.

[21] Table A.2 of API RP 1176 (1st edition, 2016) summarized mostly the same values captured in the 2015 edition of the *CEPA Recommended Practices for Managing Near-neutral pH Stress Corrosion*. For the rates determined from operating failures, the 0.3 mm/yr to 0.63 mm/yr range was associated with environmental growth rates observed on a 914.4 mm OD pipeline, while the 0.03 mm/yr to 0.16 mm/yr range was associated with SCC ruptures on 219.1 mm OD and 273.1 mm OD pipelines (upper bound) and features located adjacent to the failure sites (lower bound).

[22] The collective responses are intended to allow ECC members and other pipeline operators to note a range of observations and issues encountered by different companies.

- Challenges of ILI technologies in detecting, identifying, and accurately sizing SCC colonies consistently.

What specific changes have been made to the program in recent years relative to activities at the beginning of the program (e.g., inspection technology selection, reassessment interval, crack growth rate assumption, moderating operating pressure cycles)?

- Transition to probabilistic assessment for re-inspection intervals
- Probabilistic growth modeling that incorporates SCC-specific and mechanical crack growth rates
- Validation and as-needed adjustment of re-inspection intervals based on probabilistic/risk-based assessments
- Changes to crack growth rate assumptions
- Initiation of program with Operations and Control Center teams to raise awareness of impact of pressure cycling severity on the growth of A-SCC in liquid pipelines
- Improvements made to pipeline operations to achieve more consistency and predictability across pipeline network
- Creation of internal database to track material test records and pipeline fracture toughness properties.

What are the current challenges within the existing program?

- A need for guidance on fracture toughness or CVN values to use for pipeline segments with unknown or missing data
- A need for a standardized approach to establish appropriate safety factors
- Limitations of ultrasonic crack technology to detect shallow NN-pH SCC
- Validation of ILI reported A-SCC profiles
- Determination of re-inspection interval for pipeline segments with as-found SCC below ILI tool reporting threshold or for segments with all limited reported SCC features mitigated
- Adjustments to program activities with pressure increase or changes
- Probability of identification of MFL-based ILI technology
- A need for a concise summary of the limitations and assumptions for different crack assessment methods commonly used in the industry.

3.3.9 Condition Monitoring

An existing pipe segment remains susceptible to NN-pH SCC unless it has been replaced with non-susceptible pipe or recoated with a high-performance coating type. Condition monitoring is likened to the "check" activity in the "Plan-Do-Check-Act" process. In this Step 9 of the SCC MP, results and information gathered from relevant program activities in the preceding steps are reviewed and analyzed. The purpose is to identify ongoing or new activities required to address remaining SCC features in the pipe segment or to assess any significant changes to susceptible conditions.

Condition monitoring may involve one or more of the following activities:

- Inspecting exposed pipe for SCC at all opportunistic and integrity-driven excavations.

- Monitoring for an increased level of coating disbondment (e.g., via EMAT technology or inferred from MFL data of areas of shallow general external corrosion).
- Monitoring CP system effectiveness to determine whether the pipeline segment is adequately protected.
- Correlating ILI results with NDE results to assess tool performance and analyze outlier events including higher-than-predicted crack growth.
- Perform pressure cycling fatigue analyses when required due to significant changes to operating conditions[23].
- Integrating data from other ILI technologies or from other relevant program activities such as geohazards management.

[23] An annual download of pressure data from the SCADA system at the smallest time intervals may be beneficial for future analyses even if an annual pressure cycling analysis were not to be performed for a particular segment with observed SCC.

3.4 Circumferential SCC[24]

3.4.1 Definition and Characteristics of C-SCC

Circumferential SCC is SCC oriented predominantly circumferentially to the pipe axis and includes off-axis or oblique angled SCC[25] following the helical seam of tape coating overlaps. C-SCC is typically observed on pipe in contact with an NN-pH environment, but cracking morphology can be transgranular or intergranular.

The susceptibility conditions in Table 1 for A-SCC apply to C-SCC; the difference pertains to the sources, magnitude, and orientation of tensile stresses acting on the pipe segment to cause crack initiation and growth. For C-SCC to initiate, the total or combined local axial stresses[26] need to exceed the hoop stress.

3.4.2 C-SCC Management Program

3.4.2.1 Susceptibility Assessment

<u>Step 1: Pipe segment SCC susceptibility assessment</u>

To date, C-SCC has not been reported on pipes coated with FBE in the mill and on joints coated with liquid epoxy. Historically, C-SCC was viewed as a threat associated with pipe movement at active slopes (Sutherby, 1998). In recent years, while C-SCC has still been observed on pipe segments exposed to significant axial stress (Brimacombe, Henning, & Wargacki, 2016), there have been more reported cases of C-SCC among many pipeline operators, including ECC operators, at locations away from geotechnical hazards.

<u>Step 2: Investigate for the presence of SCC</u>

Similar for A-SCC, confirmation of susceptibility relies on digs at locations assessed to be most likely of finding C-SCC or on ILI technology.

The SCC Direct Assessment (SCCDA)[27] methodology may be successful at finding C-SCC. Sources of axial stresses can be identified from alignment sheets, topographic observations, and ILI data (e.g. inertial mapping unit data and axial strain data). The magnitude of the axial stresses from these identified sources

[24] PRCI initiated project NDE-4-24 with the objective of creating a framework to identify, assess, and mitigate the risk due to circumferential cracking threats. Under Catalogue Number PR676-233801, nine documents will be produced. As of August 2025, four deliverable documents have been issued.

[25] In Paper No. IPC2018-78564 (Johnson, Tesfaye, Wargacki, Henning, & Suarez, 2018), an ECC operator indicated finding "spider-web" cracking (i.e., cracking in different directions) in its pipeline system.

[26] In the Report of the Inquiry, the sources of axial (longitudinal) stress included internal operating pressure (one-third to one-half the circumference stress), secondary stresses causing pipe to bend such as soil settlement or landslides, and stresses due to temperature changes. In Paper No. IPC2014-33059 (Fessler & Sen, 2014), the authors added residual stresses in bent pipe and opposite rock dents as other probable sources of axial stresses.

[27] SP0204-2015 Stress Corrosion Cracking (SCC) Direct Assessment Methodology (NACE, 2015)

could be estimated[28]. A minimum number of digs would be necessary to satisfy the statistical significance test.[29]

Alternatively, C-SCC susceptibility can be confirmed with ILI technology. During the last decade, liquid-coupled UT crack detection has been successful in locating, characterizing, and sizing C-SCC and other circumferentially oriented crack-like features. In recent years, MFL-based technology has achieved a high probability of detection (POD) for locating and even accurately sizing C-SCC features. Refer to Appendix A for published articles attesting to that high success rate.

Step 3: Determine the SCC susceptibility reassessment interval

If the pipe segment was deemed to be non-susceptible to C-SCC or if a susceptible segment was found not to contain cracks, the susceptibility assessment should be periodically repeated. The re-assessment interval should consider any changes in the susceptibility factors (e.g., severe coating disbondment observed at dig sites, accelerated slope movement on a susceptible pipe segment). Similar for A-SCC, the previous edition had recommended a maximum reassessment interval of ten years. Each operator should document the rationale for the chosen reassessment interval for each pipe segment.

3.4.2.2 Condition Assessment and Mitigation

Step 4: Classify the severity of the SCC

For unmitigated C-SCC remaining on a pipeline segment, one simple classification of the features is to use the reported ILI depth if the driving factor is the avoidance of an eventual leak. For multiple features with the same depth, prioritization may consider other factors such as potential consequences at each location.

An alternative method is to assess the remaining load-carrying capacity of individual pipe joints containing one or more C-SCC features through API 579 and BS 7910 standards.[30] These assessments will be more time-consuming, especially if there are many features on a pipe segment.

A third option is to apply a strain-based assessment of the C-SCC features,[31] which could be considered more appropriate by the authors of the paper when the applied stress level is greater than 90% of yield strength. The difference between strain capacity and strain demand or the ratio of these two values provide a measure of safety margin.

Step 5: Determine and implement pipe segment safe loading condition

Although operating pressure is not the primary source of the principal stress driving crack growth, an evaluation should be completed to determine if a pressure reduction is needed prior to repair to safeguard onsite personnel. Depending on the location of the C-SCC feature to be excavated, measures should be

[28] Paper No. IPC2022-87327 (Zhang, Chune, Wang, & Kania, 2022)

[29] In the Conclusions of PRCI's "Procedure for Determining the Number of Excavations to Validate SCCDA," (Desjardins & Mackenzie, 2015) the following was stated: "Based on work completed for this project and on a literature review, reasonable values for the initial probability of the presence of significant SCC, the success rate of SCCDA and on the tar-get confidence level, the number of excavations can be expected to be between three and six in most cases."

[30] Paper No. IPC2024-133091 (McAllister, Brimacombe, Upadhyaya, Do, & Chen, 2024)

[31] Paper No. IPC2024-134065 (Wang, Warman, Liu, & Wang, 2024)

taken to reduce the level of axial stress prior to mitigation, such as relieving any soil loading or protecting exposed pipe from large temperature gradients.

Step 6: Plan and implement mitigation

Once a decision is made to mitigate C-SCC features, the current options are to remove them through, grinding (see Appendix B), pipe replacement, or steel pressure-containment (Type B) sleeves. These options align with what ECC operators have implemented for their pipeline systems.

At these locations, the source of axial stress should be identified and eliminated, if possible, for example, by:

- cutting the pipe, allowing the residual stress to relax, and inserting new pipe,
- performing strain relief,
- removing rocks from bottom-side dents,
- stabilizing pipe movement on unstable slopes, or
- moving pipe above grade.

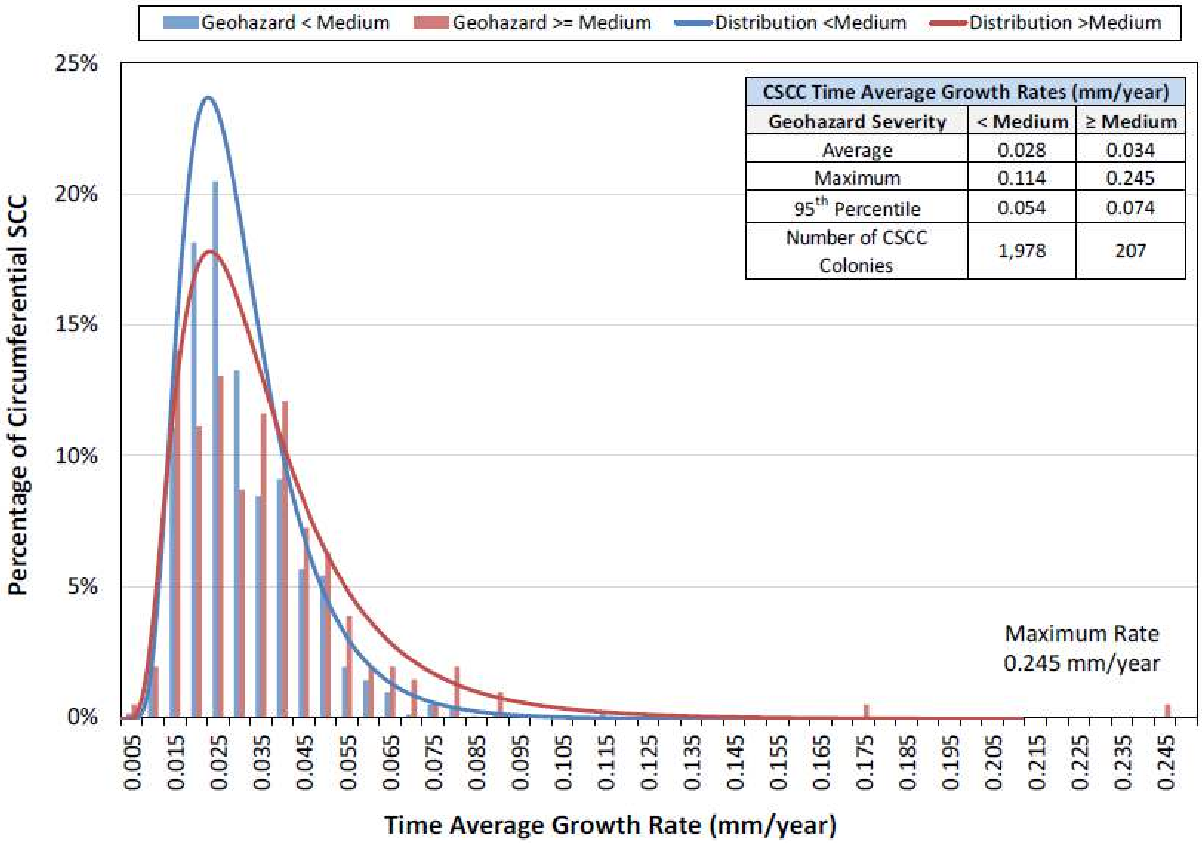
A recent Joint Industry Project was completed that evaluated the feasibility of applying certain steel and composite sleeves over C-SCC features as permanent repairs. Included among the short list was the steel compression reinforcement sleeve (Smyth, 2025). For such repairs to be accepted for use, they need to be approved by the CSA and reflected in the CSA Z662 Standard.

Step 7: Review and evaluate mitigation activities

For unmitigated C-SCC features remaining in a pipe segment that will be monitored, part of this Step 7 is to predict when they will need to be re-assessed or mitigated based on an applied growth rate. Currently, it is not known if successive ILI tool runs with the same technology by the same service provider could be used to produce individual feature crack growth rates. For a segment without an established growth rate, a value of 0.3 mm/year (0.012 in/year) was suggested as a prudent choice (Fessler & Sen, 2014). This rate would represent a conservative value relative to the time-average growth rates (calculated as the grind depth divided by pipeline age minus 10 years) determined by one ECC operator based on its C-SCC experience. These time-average depth growth rates are shown in the plot.[32] In a recent paper,[33] the authors documented an average rate of 4.72 mils/year (0.12 mm/year) based on C-SCC leaks from an operator and a 95% distribution rate of 7.13 mils/year for C-SCC (0.18 mm/year).

Each pipeline operator needs to justify an appropriate crack growth rate. Once a chosen crack growth rate has been selected, a deterministic or probabilistic assessment would then drive the timing of the next ILI and the need to mitigate any remaining C-SCC features prior to the next re-assessment.

[32] Paper No. IPC2018-78315 (Bates, Brimacombe, & Polasik, 2018)
[33] Paper No. IPC2024-134065 (Wang, Warman, Liu, & Wang, 2024)



3.4.2.3 Condition Monitoring

<u>Step 8: Document, learn, and report</u>

Like A-SCC, documentation of decisions and records of program activities related to C-SCC assessment, inspection, mitigation, and monitoring need to be created and retained.

ECC operators also provided the following feedback for the same questions asked in Section 3.3.8:

What aspects of the SCC management program have been found to be surprising or unexpected to date?

- Discovery of C-SCC in locations where mechanisms of growth are absent (or unknown)
- Different crack growth rates for C-SCC and A-SCC
- Challenges of ILI technologies in detecting, identifying, and accurately sizing SCC colonies consistently.

What specific changes have been made to the program in recent years relative to activities at the beginning of the program (e.g., inspection technology selection, reassessment interval, crack growth rate assumption, moderating operating pressure cycles)?

- Transition to probabilistic assessment for re-inspection intervals
- Changes to crack growth rate assumptions

- Creation of internal database to track material test records and pipeline fracture toughness properties.

What are the current challenges within the existing program?

- Susceptibility criteria for C-SCC[34]
- A need for an accurate failure stress (fitness for service) assessment method for C-SCC
- An ability to estimate strain demand at C-SCC sites
- Estimates of C-SCC growth rates
- Limitations of ultrasonic crack technology to accurately size off-axis NN-pH SCC
- Struggle of ILI tools to accurately characterize complex crack morphologies, especially when cracks interact with corrosion or deformation features
- Determination of re-inspection interval for pipeline segments with as-found SCC below ILI tool reporting threshold or for segments with all limited reported SCC features mitigated
- Probability of identification of EMAT ILI technology.

<u>Step 9: Condition monitoring</u>

Similar for A-SCC, an operator should have a process for collecting, regularly reviewing, interpreting, and responding to all CSCC-relevant information obtained during on-going operational and integrity management activities.

In addition to the factors described in Section 3.3.9, the following factors that particularly affect CSCC susceptibility should be monitored:

- Movement on unstable slopes,
- Unusually large precipitation events (snowfall, rain) in areas subject to soil movement, and
- Drastic changes in operating temperature that may increase (or decrease) the thermal stress in the axial direction.

[34] An ECC member noted that a lack of clear understanding of the mechanisms driving C-SCC formation affects susceptibility modeling and prioritization.

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Appendix A In-Line Inspection

A.1 Introduction

API RP 1176 provides information about ILI technologies, including their challenges and limitations. This appendix summarizes a selection of published research and operating experience involving the successes of ultrasonic and magnetic flux leakage (MFL) technology in the detection, characterization, and sizing of axial and circumferential NN-pH SCC.

A.2 Ultrasonic Technology[35]

A.2.1 Liquid-coupled Angle Beam

- Paper No. IPC2016-64111: “Circumferential crack detection: Challenges, solutions, and results” (Brimacombe, Henning, & Wargacki, 2016)
- Paper No. IPC2018-78315: “Development and experiences of a circumferential stress corrosion crack management program” (Bates, Brimacombe, & Polasik, 2018)
- Paper No. IPC2018-78564: “Complex circumferential stress corrosion cracking – Identification, sizing and consequences for the integrity management program” (Johnson, Tesfaye, Wargacki, Henning, & Suarez, 2018)

A.2.2 Phased Array

- Paper No. IPC2010-31079: “A case study of the crack sizing performance of the ultrasonic phased array combined crack and wall loss inspection tool…” (Hrncir, et al., 2010)

A.2.3 Electromagnetic Acoustic Transducer (EMAT)

EMAT technology has been in commercial use for approximately twenty years, with different generations of performance and enhancements.

- Paper No. IPC2012-90240: “Validation of EMAT technology for gas pipeline crack inspection” (Kania, et al., 2012)
- Paper No. IPC2012-90021: “The role of effective collaboration in the advancement of EMAT inline inspection technology for pipeline integrity management: A case study” (Sutherland, et al., 2012)
- Paper No. IPC2014-33567: “Evaluation of EMAT tool performance and reliability” (Kania, Rosca, Tandon, Gao, & Krishnamurthy, 2014)

[35] In Paper No. IPC2022-87663, an ILI service provider discussed the development of a gas-coupled ultrasonic tool as an alternative to EMAT technology. This technology has progressed further in its development since the publication of the paper and could be deployed for an inspection in an operating pipeline in 2025 or 2026.

- Paper No. IPC2020-9624: “Now You SCC Me, Now You Don’t – Using Machine Learning to Find Stress Corrosion Cracking” (Smith, Blenkinsop, Capewell, & Kerrigan, 2020)
- Paper No. IPC2020-9494: “Overcoming challenges of EMAT inline inspection validation for SCC management in natural gas pipelines: A practical approach” (Phlipot, Rapp, Whaley, Spencer, & Williams, 2020)
- PPIM 2021 Conference Proceedings: “Managing an EMAT ILI Program to Achieve Appropriate Margins of Safety in Natural Gas Pipelines” (Spencer, Williams, Phlipot, Whaley, & Rapp, 2021)
- Paper No. IPC2024-134085: “Comparing depth sizing of complex field SCC (NNpH and high pH) between ILI, NDT and laboratory methods” (Gamboa, Hazeltine, Cano, & Cornejo, 2024)
- PPIM 2025 Conference Proceedings (pages 1163 – 1176): “EMAT-C ultra technology for crack inspection in gas pipelines” (Hilvert, Freitas, & Beuker, 2025)

A.3 MFL Technology

Originally developed for the detection and sizing of corrosion features, MFL technology has demonstrated its ability to locate, characterize, and size SCC (and other crack-like features) when fluxes in the axial and circumferential directions are applied in tandem.

A.3.1 Axial SCC

- No published data as of the writing of this document

A.3.2 Circumferential SCC

- PPIM 2021 Conference Proceedings: “Circumferential Crack Detection Using Ultrasonic ILI, a Key Element within a Successful Crack Management Strategy” (Guillen, Boekers, Klinge, Valderrama, & Baby, 2021)
- PPIM 2021 Conference Proceedings: “Pipeline Integrity Management of CSCC Using Multiple ILI Technologies” (Thompson, et al., 2021)
- PPIM 2025 Conference Proceedings (pages 1673 – 1684): “Highlighting the Threat of Circumferential Stress Corrosion Cracking (CSCC) with Advanced Inline Inspection Tools” (Romney, Hardy, & Burden, 2025)

Appendix B Grinding Repair

CSA Z662:23 permits SCC features to be removed by grinding or buffing but limits such grinding to 40% of the nominal pipe wall thickness[36]. Refer to PRCI's "Grinding Limits for Repair of SCC on Operating Pipelines" (Gould, Bruce, & Arnett, 2017) and Section 4.2 of PRCI Pipeline Repair Manual: 2021 Edition for additional information and guidance on grinding.

Removal of SCC by buffing, with or without subsequent reinforcement, is a common repair procedure (Figure B.1). The SCC is generally removed by sequentially buffing the feature so that the minimum of pipe material is removed and information about the crack dimensions can be accurately collected.

SCC features should not be removed by grinding on pipe at high pressure. With pipe operating at high pressure, only buffing using soft back or flap discs[37] should be carried out. The operator should determine a safe pressure prior to any repair process that reduces the load-bearing capacity of the pipe. If grinding or buffing results in localized metal loss that exceeds the limits specified in the ASME B31G code, a temporary (e.g., bolt-on split sleeve) or permanent sleeve repair can be made.

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[36] Section 4.2 of PRCI's Updated Pipeline Repair Manual: 2021 Edition (Bruce, Gould, Bubenik, Alexander, & Rosenfeld, 2022) states the following: "Grinding to remove cracks that are deeper than 40% should not be allowed even if the resulting grind defect will be subsequently repaired by an appropriate method. The 40% limit is intended as a safeguard against failure during grinding. When grinding on a live pipeline, if the potential stress change due to grinding is not properly addressed, there is a risk that the pipe wall will rupture, either by reducing the wall thickness to below that which is appropriate for the operating pressure or by causing the cracking that is being removed to become 'critical' or unstable as the result of increased local stresses. Research has shown that grinding from the center outward may help to determine the depth of the crack without destabilizing the defect area, as removal of 75% of the crack depth may be required before a noticeable improvement in the failure pressure is achieved."

[37] A flap disc minimizes excessive heat input during the grinding operation. As stated in the 2021 Pipeline Repair Manual: "The flap disk [sic] should be angled into the material just under 180^0 to the plane of its surface using a back and forth sweeping motion with moderate pressure."

Figure B.1. Buffing Repair

The sequential buffing process typically involves the following steps:

- Select the isolated SCC feature, the deepest feature within a colony, or the SCC located at the toe of a longitudinal weld. For a feature at the toe of the weld, the weld should be inspected using a volumetric NDE method (e.g., radiography or UT) to confirm there is sufficient sound metal under the weld cap before any grinding activities. The weld cap is then removed flush to the pipe for the initial assessment.
- Review the pressure reduction established for the excavation. Considering the length of the crack being removed and the potential interacting effect of adjacent cracks, determine the maximum safe depth of material that can be removed by buffing at the established pressure reduction.
- Depending on the estimated depth and precision of the data required, remove slightly less than 10% of the wall thickness and perform magnetic particle inspection (MPI) to determine if any SCC remains within the buffed area.
- Measure the remaining wall thickness using an ultrasonic thickness gauge.
- If the SCC were removed in the first step, record the depth as less than 10% of wall thickness.
- If the SCC remains within the buffed area, perform a second buffing followed by MPI inspection and wall thickness measurements. The amount of material removed in the second pass should be substantially less than the first pass, typically in the range of 1% to 3% of the nominal wall thickness, depending on the depth precision required.
- Continue the sequential buffing, MPI inspection, and wall thickness measurements until either the SCC feature is completely removed, or the safe buffing depth has been reached as established above.

- As the buffing progresses nearer to the crack tip, consecutive buffing should remove increasingly less material in the depth direction to increase precision of the measurement and minimize wall loss to the pipe.

Appendix C Field Data Collection

The proposed data sets are based on thousands of digs over decades but should be used as a guideline only. Each pipeline operator can decide what additional or alternative parameters to collect as deemed valuable for specific dig sites.

In many cases, the data described below have shown a relationship with aspects of SCC. In other cases, operational experience and the results from research and development (R&D) studies suggest some correlation, and the collection of these data is considered to have value in the context of continuous improvement of SCC management.

C.1 Learning from All SCC Opportunities

Data should be collected from all investigation activities such as ILI validation digs, hydrostatic test failure repairs, in-service failures, and opportunistic digs.

During validation digs, data should be collected to allow a comparison between the reported ILI feature and that found from the excavation. This comparison should take into consideration the ILI service provider's specification regarding interaction rules, crack size detection limits, etc. Feeding this information back to the ILI service provider can significantly improve the detection and sizing capability during the analysis of ILI data.

C.2 Data Collection

Data analysis is used to assess the susceptibility of pipeline segments and to select sites to investigate for the presence of SCC or for condition monitoring. The basis of these decisions is the correlation between SCC and certain system attributes (e.g., construction, environmental, operating, and maintenance data).

C.2.1 Inspection Excavations

When a field excavation program is implemented, observations should be recorded for each site, including the terrain, the performance of the materials of construction, the environment in contact with the pipe, and characteristics of any as-found cracking or other pipe anomalies.

C.2.2 Standardized Field Data Collection

Field data collected for the purpose of operational learning on a system requires that the data be documented consistently and spatially referenced. Consistent terminology and data collection enable meaningful organization and analysis.

C.2.3 Spatial Referencing

In the field, data collection begins with ground-level site observations and measurements and progresses to below-ground observations as the pipe is exposed (Figure C.1).

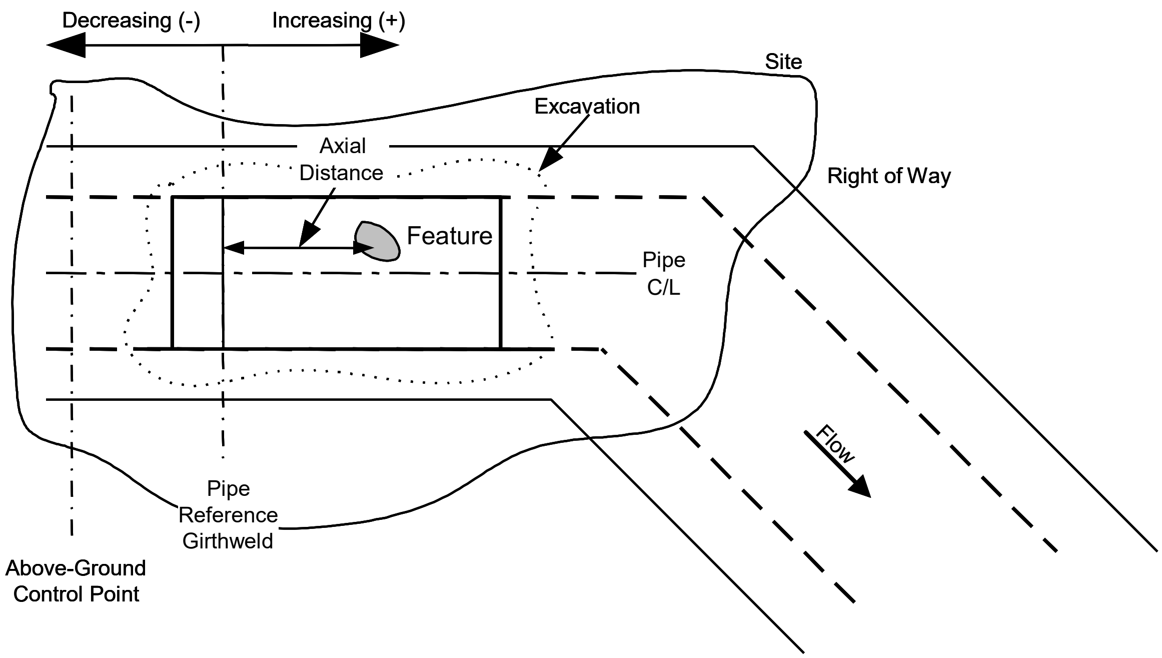

Figure C.1. Axial and Circumferential Referencing

The position of an above-ground reference point is measured axially from a control point along the centre line of the pipe, such as a valve or a pipe transition. After excavation the reference system is extended to the pipe. By convention, the pipe reference point is the girth weld furthest upstream in the excavation. GPS readings should be obtained for at least the above-ground reference point and reference girth weld for validation tracking purposes.

Feature locations on the pipe (e.g., coating or pipe surface features) are recorded in terms of axial and circumferential positions. Axial position is measured from the reference girth weld with positive distance increasing in the direction of flow and negative distance increasing in the upstream direction.

Circumferential positions on the pipe are recorded as either o'clock or distance from the top of the pipe in the clockwise direction. O'clock orientation is estimated according to the circumferential position with 12:00 being the top and clockwise proceeding to the right when looking downstream along the pipe centre line.

C.3 Excavation Data Collection and Tables

The Dig Data table (Table C.1) is used to collect data relating to the excavation site and consists mainly of information collected ahead of the excavation based on available records. This table contains information that could be useful to the company or its contractor to locate and survey the site. Such data include planning and administrative information including the excavation date, the name or line number, the location relative to the upstream pump or compressor station, the location and type of above ground reference point, etc. These data should be compiled during the planning or site surveying phase ahead of the actual excavation. A company may choose to augment this table with information relating to the contractor or the company representative involved.

Table C.1. Dig Data

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
Date	Date	Date of the dig
GPS latitude direction	N/A	Latitude direction
GPS latitude	N/A	Latitude (hours, minutes, seconds)
GPS longitude direction	N/A	Longitude direction
GPS longitude	N/A	Longitude (hours, minutes, seconds)
Line number	N/A	Line number
Line name	N/A	Line name
Above ground marker	N/A	Above ground marker type
Above ground site chainage	m	Distance from ground marker to start of dig or start stake
Upstream station name	N/A	Name of the upstream compressor/pump station
Distance to upstream station	m	Distance from station to of dig or start stake
Reference weld chainage	m	Distance from start of dig or start stake to the reference girth weld
MOP	kPa	Maximum operating pressure
Land use	N/A	Use of land [**Recommended descriptions**: abandoned, agriculture, aquatic, commercial, cultivated, desert, grassland, gravelled, grazing, paved, prairie, residential, rock, woodland]
Physiographic region	N/A	Physiographic region [**Recommended descriptions**: Canadian Shield, Coastal, Cordilleran, Interior Plains, St. Lawrence Lowlands, Mississippi Valley]
Vegetation legend	N/A	Vegetation [**Recommended descriptions**: boreal, coastal, deciduous, desert, grasslands, montane alpine]
Notes	N/A	Other notes
Grade	MPa	Grade of pipe

C.3.1 Weld and Pipe Characteristics Table

In each SCC excavation, observed features above and below ground are recorded relative to axial and circumferential references (Table C.2). Each girth weld in the excavation is assigned a Weld ID, generally in reference to a particular ILI survey.

Table C.2. Weld and Pipe Characteristics

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
Weld ID	N/A	Unique identifier for the girth weld
Manufacturer	N/A	Pipe manufacturer [**Recommended descriptions**: Alberta Phoenix, A.O. Smith, BHP, Berg, Bergrohr, Bethlehem, Camrose, Camrose Tubes, Canadian Phoenix, Consolidated, Eisenbau Kramer, Estel Hoesch, HME, IPSCO, SIAT, South Durham, Steel Mains, Stelco, Stewards Lloyds, Sumitomo, US Steel, Vallourec, Wellland Tube, Western, Youngstown]
Exposed joint length	m	How much each joint was exposed
Inspected length of cleaned pipe	m	Length of inspected pipe
Pipe diameter	mm	Pipe diameter
Actual wall thickness	mm	Actual wall thickness (10 measurements)
Avg width of tenting	mm	Average width of tenting
Seam weld type	N/A	Type of seam weld [**Recommended descriptions**: DSAW, flash, ERW, lap, seamless, spiral]
Spacing of spiral seam	cm	Spacing of the spiral seam
Long seam TDC o'clock	mm	Location of the long seam weld on the circumference of the pipe from the top dead center
Notes	N/A	Other notes

As the pipe is exposed, the first task is to establish the axial reference system using the welds and direction of flow as illustrated in Figure C.2. In addition to recording girth weld data, the pipe diameter, wall thickness, joint length, long seam weld type and circumferential position, and manufacturer should be recorded. The length of pipe to be cleaned and inspected is also recorded.

To aid in referencing observations, a scale should be applied to the pipe. This is frequently achieved by marking off metres, using spray paint, and moving upstream and downstream of the reference girth weld. All feature positions are documented relative to the upstream girth weld.

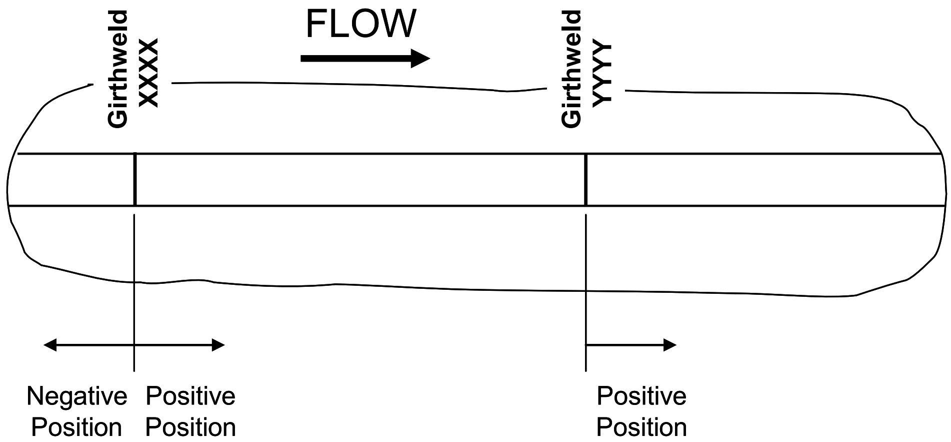

Figure C.2. Data Axial Position Reference Girth Welds

C.3.2 Terrain Data

Some companies have found correlations between SCC and certain terrain features. Potentially useful parameters include the local topography, soil texture or particle size, and the site drainage. Terms relating to deposition modes have also been used.

Various standards and systems of soil classification exist.[38] These systems have been developed to provide classification related, for example, to the engineering use of soil, agricultural use, chemical and physical properties and the development of soil based on geology, climate, and other factors. In the context of pipeline corrosion and SCC, the relevant aspects of the soil that could play a role in pipeline performance remain to be fully established. For example:

- the presence of clay, particularly swelling clays, may correlate to the degree of disbondment of tape coating;
- the degree of aeration may be indicated by the soil texture or soil gleying (characteristic of anaerobic conditions);
- the presence of groundwater, soil mottling, or poor drainage may indicate that sufficient water is available to support corrosion;
- alternatively, high soil resistivity or good drainage may indicate poor cathodic protection.

Given the specialized and varied needs of pipeline companies, rather than adhering to any one soil classification system, operators have tended to borrow and mix terms from various conventions. Two different data tables are used here to characterize soil conditions.

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[38] American Society for Testing and Materials. 2021. Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), D2488-21. ASTM International.
National Research Council of Canada. 1998. The Canadian System of Soil Classification, 3rd ed., NRC Research Press.
Canadian Soil Information Service https://sis.agr.gc.ca/cansis/index.html (includes The Canadian System of Soil Classification)

C.3.2.1 Terrain – Linear Features Table

Table C.3 records the general surface topography around the excavation and the specific position of the excavation within the topography, the local drainage, and the maximum slope percentage. Depending on the position of the excavation in the terrain, or the extent of a given drainage (e.g., if the site extends from a mid-slope position down to the slope toe), more than one entry may be made to best characterize a site. Photographs and sketches are useful.

Table C.3. Terrain - Linear Features

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the soil is measured
Feature ID	N/A	Unique identifier for the soil feature
Start from reference GW	m	Location of the start of soil with respect to the reference girth weld
Length	m	Length of the soil
Maximum slope percent	%	Maximum slope percent of the area around the pipe [**Recommended descriptions**: 0, 15, 30, 45, 60, 75, 90]
Topography	N/A	Topography of the area [**Recommended descriptions**: dunes, floodplain, hummocky, inclined, level, ridged, rolling, stream channel, undulating, depression]
Slope position	N/A	Slope position of the pipe [**Recommended descriptions**: crest, depression, level, lower, middle, toe, upper]
Surface salts	N/A	Are there any visible surface salts?
Notes	N/A	Other notes

C.3.2.2 Soil 2-D Features Table

Table C.4 records the characteristics of the major soil blocks at the pipe depth along the excavation (Figure C.3). Soil blocks are recorded in terms of their individual lengths, depths, and the position of the pipe within them. The attributes recorded for the soil blocks are the mode of deposition, the dominant and secondary textures of the soils, and indications of the presence of oxygen, gleying, water movement, and mottling. Multiple entries may be required if conditions at pipe depth vary significantly along the excavation or pipe.

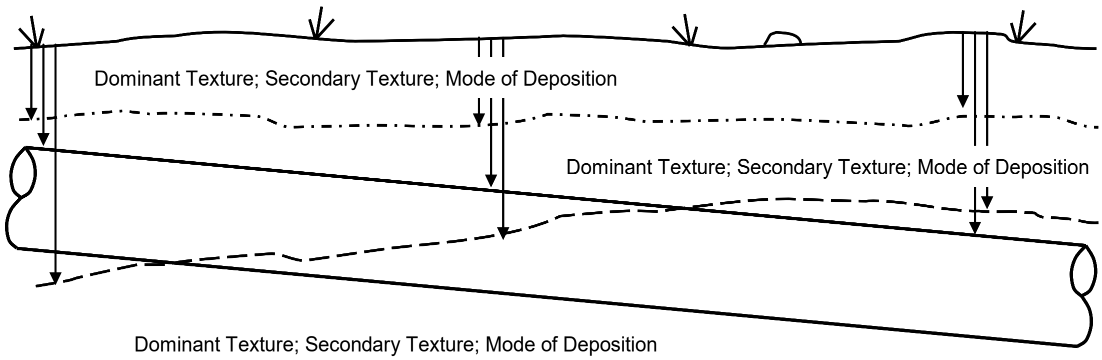

Figure C.3. Documentation of Below Ground Soil Features

A geologist, hydrogeologist, soil specialist, geotechnical engineer, or technician experienced and familiar with the classification of topography and soil characteristics should document the terrain conditions along the excavation.

Table C.4. Soil - 2D Features

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the soil is measured
Feature ID	N/A	Unique identifier for the soil feature
Start from reference GW	m	Location of the start of soil with respect to the reference girth weld
Length	m	Length of the soil at pipe depth
Depth start	m	Location of the start of pipe depth soil from ground surface
Depth end	m	Location of bottom of pipe depth soil from ground surface
Depth to pipe	m	Depth to the top of the pipe from the ground surface
Drainage	N/A	Drainage of the soil around the pipe [**Recommended descriptions**: imperfect, poor, very poor, moderately well, well]
Dominant texture	N/A	The dominant texture of the soil [**Recommended descriptions**: silt, clay, sand, till, gravel, rock, peet]
Secondary texture	N/A	The secondary texture of the soil [**Recommended descriptions**: silt, clay, sand, till, gravel, rock, peet]
Mode of deposition	N/A	The deposition process at pipe depth [**Recommended descriptions**: Colluvium, Eolian, Fluvial, Glaciofluvial, Lacustrine, Organic, Shot Rock, Till (Moraine)]

Mottling	N/A	Description of mottling feature at pipe depth [**Recommended descriptions**: none, faint, distinct, prominent]
Gleying	N/A	Description of gleying feature at pipe depth [**Recommended descriptions**: intensely gleyed (dark bluish to dark greenish-grey), strongly gleyed (dark grey), moderately gleyed (light to drab grey), slightly gleyed (patches of light greyish-brown), not gleyed (brown color dominates)]
Notes	N/A	Other notes

C.3.3 Buoyancy Table

Some cases of pipe deterioration, including the development of SCC, have occurred under concrete buoyancy control weights. At such locations, coating damage has been observed caused either by the placement of the weight during construction or movement of the weight during service. Localized environmental conditions have also been observed due to either depletion or concentration of environmental species. Such localized conditions could differ significantly from the pipe environment on either side of the concrete buoyancy control weights and could either favour or impede the development of SCC.

The Buoyancy table (Table C.5) has an entry for the composition of the weight. Buoyancy control weights fabricated with high sulphur content may create an anaerobic environment, a condition associated with near-neutral pH SCC.

Table C.5. Buoyancy

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Start from reference GW	m	Location of the start of buoyancy control device with respect to the reference girth weld
Length	m	Length of the soil at pipe depth
Type	N/A	Type of buoyancy [**Recommended descriptions**: anchor, river, saddle/swamp weights, screw anchors]
Composition	N/A	Composition of the buoyancy control device [**Recommended descriptions**: Portland, Sulphurcrete, unknown]
Removed	N/A	Was the buoyancy control device removed?
Notes	N/A	Other notes

C.3.4 Pipe-to-Soil Potentials Table

The "on" potential of the pipe should be recorded during the excavation. A pipe-to-soil potential measurement should be recorded at the soil surface and, as the pipe is exposed, measurements should also be made adjacent to the pipe at the top, side and bottom of the pipe. The measurements should be taken with respect to the reference girth weld (Table C.6).

Table C.6. Pipe-to-Soil Potentials

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Potential ID	N/A	Unique identifier for the potentials
Location	m	Location of the CP measurement with respect to the reference girth weld
Off potential	mV	Off CP potential measurement
On potential	mV	On CP potential measurement
Depolarized potential / native	mV	Depolarized pipe potential
Notes	N/A	Other notes

C.3.5 Coating Characterization

Two different tables are used to characterize the coating, one capturing general observations and the other relating to coating damage.

C.3.5.1 General Coating Condition Table

The General Coating Condition table (Table C.7) summarizes the type(s) of coating present on the exposed pipe, as well as the general condition of the coating at the time of the excavation.

Table C.7. General Coating Condition

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Coating ID	N/A	Unique identifier for the coating
Start from reference GW	m	Start of coating with respect to the reference girth weld
Length	m	Length of coating
Coating type	N/A	Coating type at time of excavation [**Recommended descriptions**: asphalt, bare, coal tar enamel, enamel, fusion bond epoxy, lagging, PE tape double, PE tape single, polyethylene, polyvinyl chloride, shrink sleeves, somastic, urethane, urethane epoxy, Yellow Jacket 1, Yellow Jacket 2, wax]
Coating condition	N/A	Coating condition as defined [**Recommended descriptions**: excellent, well, fair, poor, very poor]
Coating application on pipe	N/A	Method of coating application on the pipe [**Recommended descriptions**: factory, field – hand, field – machine]
Coating application on GW	N/A	Method of coating application on the girth weld [**Recommended descriptions**: factory, field – hand, field – machine]
Notes	N/A	Other notes

The condition of the coating is documented using the semi-quantitative criteria given in Table C.8. These descriptions include a quantitative measure of the coating quality that can be used for numerical analysis.

Table C.8. Categories of Coating Quality

Coating Condition	Extent of Tenting (Tape Coating Only)	Description of Disbonded Coating
Excellent	Very minor to non-existent	Very good adhesion; less than 1% disbondment; an occasional holiday; asphalt exhibits continuous thickness; no electrolyte beneath the coating
Well	Minor, intermittent	1% to 10% disbondment, scattered holidays; isolated disbondment due to soil stress with no associated corrosion deposits; good adhesion
Fair	Intermittent	10 to 50% disbondment; intermittent soil stress disbondment; coating damage; scattered to numerous holidays; random areas of poor adhesion; brittle coating (asphalt)
Poor	Continuous	50% to 80% disbondment; numerous holidays; multiple or continuous areas of poor adhesion; interlinked soil stress disbondment with associated deposits; coating damage; very brittle coating (asphalt)
Very poor	Continuous	>80% coating failure; no adhesion, numerous holidays; interlinked soil stress disbondment with associated corrosion deposits; coating damage; very brittle coating (asphalt)

C.3.5.2 Discrete Coating Damage Table

Table C.9 documents the mapping of coating damage, including tape “tenting,” on the pipe relative to the excavated pipe reference system. Table C.9 should be completed for each disbondment on the excavated pipe. Photographs or drawings are useful.

Table C.9. Discrete Coating Damage

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Coating damage ID	N/A	Unique identifier for the coating damage
Start from reference GW	m	Location of nearest point of damage with respect to the reference girth weld
Length	m	Length of the damage
Width	mm	Width of the damage
Feature from TDC	mm	Distance from top dead center of feature
Type of coating damage	N/A	Type of damage [**Recommended descriptions**: disbondment, holiday]
Wet underneath	N/A	Is the disbondment we underneath? [**Recommended descriptions**: yes, no, unknown]
LS tenting > 50 mm	N/A	Is there long seam weld tenting greater than 50 mm in length?
Notes	N/A	Other notes

C.3.6 Sampling and Analysis

Prior to, or during coating removal, the presence of corrosion deposit(s) or water beneath the coating should be noted. If possible, corrosion deposits should be identified and captured in Table C.10. Combined with other specific environmental parameters, certain deposits may be correlated to either the presence or absence of SCC and can provide information related to the chemical environment beneath disbonded coatings.

Table C.10. Sampling and Analysis

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S weld ID	N/A	Unique identifier for the upstream girth weld from which the test is measured
Coating ID	N/A	
Test ID	N/A	Unique identifier for the corrosion test
Sample type	N/A	Type of sample(s) taken [**Recommended descriptions**: coating, deposit, groundwater, soil, water from undercoating]
Test material type	N/A	Type of test taken
Colour	N/A	Test colour [**Recommended descriptions**: black, blue, brown, clear, green, grey, light green, orange, red, white, yellow]

Texture	N/A	Test texture [**Recommended descriptions**: crystal, film, hard, liquid, metallic, pasty, powdery, scaly, waxy]
Visual deposit type	N/A	Visual test type
Distribution	N/A	Distribution of the test on the pipe [**Recommended descriptions**: continuous, dense, intermittent]
Start depth	m	Start depth of test
Axial distance	m	Location of the measurement from the reference girth weld
Soil test depth	m	Depth of which soil test was taken
Corrosion deposit description	N/A	Distribution of corrosion deposits [**Recommended descriptions**: continuous, dense, intermittent]
Feature from TDC	N/A	Distance of the feature from the TDC of the pipe
Field pH	N/A	pH of the test in the field
Method of assessment	N/A	Method of assessing the test [**Recommended descriptions**: visual, field test kit]
Test taken	N/A	Was a test taken? [**Recommended descriptions**: yes/no]
Adherence to coating	N/A	Does the deposit adhere to the coating? [**Recommended descriptions**: yes/no]
Adherence to pipe	N/A	Does the deposit adhere to the pipe? [**Recommended descriptions**: yes/no]
Composition	N/A	Composition of the corrosion product (lab analysis recommended) [**Recommended descriptions**: CaCO3, electrolyte, iron oxide/hydroxide, FeCO3, FeS, LGF, NaHCO3, organic, unknown]
Notes	N/A	Other notes

Corrosion deposits are documented according to physical attributes such as colour, texture, and distribution. Commercially available test kits can be used to qualitatively identify the composition of deposits.

The pH of water samples should be determined as soon as possible after exposure of the pipe as the pH of trapped water can change with time. Litmus paper is the most common technique and can be used even if there is only superficial moisture on the pipe.

NN-pH SCC has been observed to occur in the presence of under-coating waters with pH in the range 5.5 to 7.5. In contrast high-pH SCC occurs at pH greater than 9.3.

In the case of NN-pH SCC, the under-coating water can contain dissolved carbon dioxide that, over time, can evolve with a corresponding increase in pH level. Therefore, pH measurements should be taken as soon as possible during inspection. The pH of the trapped water can also decrease over time due to the oxidation of dissolved ferrous ions and the subsequent hydrolysis of the resulting ferric ions.

C.3.7 SCC Table

Following removal of the coating and the completion of MPI, any SCC that is present is documented using the SCC table (Table C.11) and/or the Toe Cracks table (Table C.12).

Table C.11. SCC

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
SCC colony ID	N/A	Unique identifier for the SCC colony
Start from reference girth weld	m	Location of the start of the SCC with respect to the reference girth weld
Colony length	mm	Length of the colony
Colony width	mm	Width of the colony
Angle of the colony	degrees	Angle of the SCC colony with respect to the pipe axial location [**Recommended descriptions**: 0 – 30 degrees, 30 – 60 degrees, 60 – 90 degrees]
Average crack length	mm	Average length of the cracks
Maximum crack length	mm	Maximum length of the cracks
Maximum crack depth	mm	Maximum depth of the cracks
Depth determination method	N/A	The method used to determine the depth of the crack [**Recommended descriptions**: grinding, NDT, visual]
Evidence of cracks interlinking	N/A	Is there evidence of the cracks interlinking? [**Recommended descriptions**: yes, no, unknown]
Maximum interlinked crack length	mm	Maximum interlinked crack length
Colony circumferential width	mm	Width of the colony
Feature from TDC	mm	Distance from center of colony to the top dead center of the pipe
Orientation	N/A	Direction that the distance from the TDC was measured [**Recommended descriptions**: clockwise (CW), counterclockwise (CCW)]
Crack morphology	N/A	Morphology of the crack

		[**Recommended descriptions**: intergranular, transgranular]
Crack morphology method	N/A	Method of determining the crack morphology [**Recommended descriptions**: in-situ metallography, not determined, unknown]
Shape	N/A	Shape of the colony [**Recommended descriptions**: rectangular, linear]
Toe crack	N/A	Is there a toe crack?
Side-to-side crack spacing	mm	Horizontal distance between cracks
Tip-to-tip crack spacing	mm	Horizontal distance between cracks
Grind feature start	m	Location of the nearest point of the grind area with respect to the reference girth weld
Grind feature length	m	Length of the grind area
Grind feature circumferential width	m	Circumferential width of the grind area
Centre of grind feature TDC	N/A	Location of the centre of the grind area on the circumference of the pipe
Orientation of the grind area	N/A	
Average depth of grind feature	mm	Average depth of the grind area
Maximum depth of grind feature	mm	Maximum depth of the grind area
MPI method	N/A	Method of magnetic particle inspection used [**Recommended descriptions**: colour contrast, fluorescent]
Photos	N/A	Yes / no
Notes	N/A	Other notes

SCC occurs in patches or colonies typically containing from a few to thousands of individual cracks. An SCC colony is defined as an independently acting feature, the dimensions of which (length and depth) would be used to estimate the failure pressure for that feature. For relatively deep cracks, the dimensions of the colony are defined by the crack interaction rules. For shallow non-injurious cracks (<10% of the wall thickness), the exact dimensions of the colony are less important as such features do not represent an integrity concern. Comparison of the number of colonies per joint has been used to characterize the relative severity of the SCC found.

Cracks often exhibit a stair-case pattern with axial spacing less than 1 mm. Overlapping cracks showing indications of coalescence are deemed to be "interacting" and treated as a single crack feature (Figure C.4).

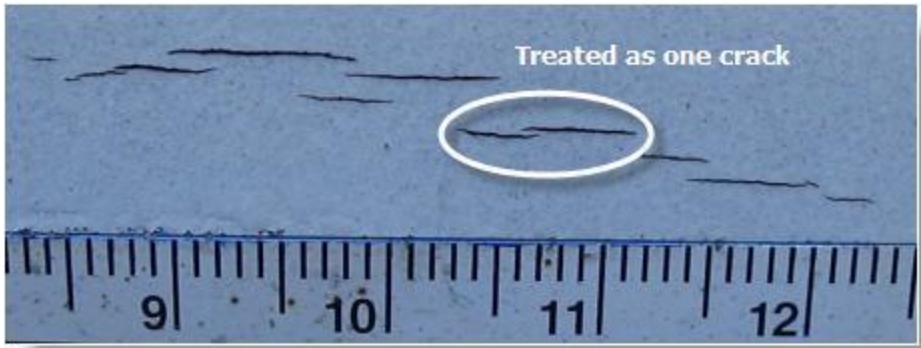

Figure C.4. Example of interacting SCC

For documentation, each colony is assigned a unique identifier. If toe cracks were observed, their details are captured separately in Table C.12.

Where there is potential for more than one form of SCC, the morphology of cracking may also be determined. Some inspection companies offer in situ determination of the crack morphology, i.e., whether cracks are intergranular or transgranular.

C.3.8 Toe Cracks Table

Cracks located at the toe of the long seam weld may or may not be SCC. As a result of their position, co-linear orientation and mechanistic uncertainty, toe crack data are recorded separately from pipe body SCC.

When SCC inspections are conducted using MPI, a crack-like indication is often noted at the edges of the long-seam welds. Indications may be the result of weld imperfections, such as roll-over or undercut, or they may be more significant features, such as lack of fusion or cracking. Such indications need to be assessed with caution to avoid overlooking SCC. Frequently, lightly filing or buffing the cap of the weld flush with the pipe surface can facilitate interpretation of the indications.

Table C.12. Toe Cracks

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Toe crack ID	N/A	Unique identifier for the SCC toe crack
Start from reference GW	m	Location of the start of the SCC with respect to the reference girth weld
Toe crack length	mm	Length of the toe crack
Toe crack width	mm	Width of the toe crack
Average crack length	mm	Average length of the cracks
Maximum crack length	mm	Maximum length of the cracks
Maximum crack depth	mm	Maximum depth of the cracks
Depth determination method	N/A	Method used to determine the depth of the crack

		[**Recommended descriptions**: grinding, NDT, visual]
Evidence of cracks interlinking	N/A	Is there evidence cracks are interlinking? [**Recommended descriptions**: yes, no, unknown]
Maximum interlinked crack length	mm	Maximum length of interlinked crack
Feature from TDC	mm	Distance from the center of the toe crack to the top dead center of the pipe
Crack morphology	N/A	Morphology of the crack [**Recommended descriptions**: intergranular, transgranular, unknown]
Crack morphology method	N/A	Method of determining the crack morphology [**Recommended descriptions**: in-situ metallography, not determined]
Tip-to-tip crack spacing	mm	Horizontal distance between cracks
Grind feature start	m	Location of the nearest point of the grind area relative to the reference girth weld
Grind feature length	mm	Length of the grind area
Average depth of grind feature	mm	Average depth of the grind area
Maximum depth of grind feature	mm	Maximum depth of the grind area
Notes	N/A	Other notes

Since toe cracks are often present as a line of cracks instead of colonies, their depths can be determined accurately with shear-wave, phased array, and time-of-flight diffraction (TOFD) ultrasonic inspection techniques[39].

C.3.9 Pipe Surface Damage

Where either metal loss or pipe surface damage is present in the excavation, the relative circumferential and axial positions and geometries of such features should be documented in Table C.13 or Table C.14. Pipe surface damage can be due to dents and/or gouges, arc strikes, wrinkles, or metallurgical hard spots.

[39] Refer to API RP 1176 for additional information on various NDE techniques and their applications.

Table C.13. Coincident Corrosion

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
Corrosion ID	N/A	Unique identifier for the corrosion feature
Corrosion type	N/A	Type of corrosion [**Recommended descriptions**: channeling, general, pitting, superficial)
Start from reference GW	m	Location of the nearest point of the corrosion feature with respect to the reference girth weld
Length	mm	Length of the corrosion feature
Width	mm	Width of the short dimension of corrosion feature
Angle	degrees	Angle of the corrosion feature [**Recommended descriptions**: 0 – 30 degrees, 30 – 60 degrees, 60 – 90 degrees)
Average depth	mm	Measured average depth of remaining wall thickness
Maximum depth	mm	Measured maximum depth or remaining wall thickness
Actual WT	N/A	Actual wall thickness at the corrosion feature
Feature from TDC o'clock	N/A	Distance from top dead center to the center of the corrosion feature
Associated cracks	N/A	Are there cracks associated with the corrosion feature? [**Recommended descriptions**: yes, no, unknown]
Notes	N/A	Other notes

Table C.14. Coincident Mechanical Damage

Field Name	Units	Description
Dig ID	N/A	Unique identifier for the dig
U/S Weld ID	N/A	Unique identifier for the upstream girth weld from which the feature is measured
MD ID	N/A	Unique identifier for the mechanical damage feature
Mechanical Damage Type	N/A	Type of mechanical damage [**Recommended descriptions**: buckle, wrinkle, dent, gouge, hard spot, arc burn]
Start from reference GW	m	Location of the start of the damage feature with respect to the reference girth weld
Length	mm	Length of the damage feature from the start point
Width	mm	Width of short dimension of mechanical damage area
Feature from TDC o'clock	mm	Distance from the top dead center to the center of the mechanical damage feature
Depth	mm	Depth of the dent
Average WT	mm	Average wall thickness within the damage area
Peak-to-peak depth	mm	Peak-to-peak depth
Wavelength	mm	Distance between successive peaks or troughs in the dent profile
Corrosion in dent	N/A	Is there corrosion in the dent?
Crack in dent	N/A	Is there SCC in the dent?
Notes	N/A	Other notes