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Standard Practice

Stress Corrosion Cracking (SCC) Direct Assessment Methodology

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Foreword

Stress corrosion cracking direct assessment (SCCDA) is a structured process that is intended to assist pipeline companies in assessing the extent of stress corrosion cracking (SCC) on a section of buried pipeline and thus contribute to their efforts to improve safety by reducing the impact of external SCC on pipeline integrity. Primary guidance for assessing the structural integrity of a pipeline that has a significant risk of containing stress corrosion cracks is provided in Part A3 of ASME[(1)] B31.8S,[1] which identifies several options for inspection and mitigation activities. The recommended practice for SCCDA presented in this standard addresses the situation in which a pipeline company has identified a portion of its pipeline as an area of interest with respect to SCC based on its history, operations, and risk assessment process and has decided that direct assessment is an appropriate approach for integrity assessment. This standard provides guidance for managing SCC by selecting potential pipeline segments, selecting dig sites within those segments, inspecting the pipe, collecting and analyzing data during the dig, establishing a mitigation program, defining the reevaluation interval, and evaluating the effectiveness of the SCCDA process.

This standard practice is intended for use by pipeline operators and others who must manage pipeline integrity for the threat of SCC. SCCDA as described in this standard is specifically intended to address buried onshore petroleum (natural gas, crude oil, and refined products) production, transmission, and distribution pipelines constructed from line-pipe steels. Users of this standard must be familiar with all applicable pipeline safety regulations for the jurisdiction in which the pipeline operates. This includes all regulations requiring specific pipeline integrity assessment practices and programs.

This standard was originally prepared in 2004 by NACE Task Group (TG) 273, "Stress Corrosion Cracking Direct Assessment, External," which is administered by Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings," and it was reaffirmed in 2008 by STG 35. This standard is issued by NACE under the auspices of STG 35.

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*. The terms *shall* and *must* are used to state a requirement, and are considered mandatory. The term *should* is used to state something good and is recommended, but is not considered mandatory. The term *may* is used to state something considered optional.

(1) ASME International (ASME), Three Park Avenue, New York, NY 10016-5990

NACE International
Standard Practice

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Section 1: General

1.1 Introduction

1.1.1 This standard covers the NACE SCCDA process for buried steel pipeline systems. It is intended to serve as a guide for applying the NACE SCCDA process on typical petroleum (natural gas, crude oil, and refined products) pipeline systems. Background information can be obtained from NACE Publication 35103.[2]

1.1.2 SCCDA as described in this standard is specifically intended to address buried onshore petroleum (natural gas, crude oil, and refined products) pipelines constructed from line-pipe steel.

1.1.2.1 This procedure is designed to be applied to both forms of external SCC (near-neutral-pH SCC and high-pH SCC) on these pipelines.

1.1.3 SCCDA requires the integration of data from historical records, indirect surveys, field examinations, and pipe surface evaluations (i.e., direct examination) combined with the physical characteristics and operating history of the pipeline.

1.1.4 This standard was written as a flexible guideline for an operator to tailor the SCCDA process to specific pipeline situations. Nothing in this standard is intended to preclude modifications that tailor the SCCDA process to specific pipeline situations and operators.

1.1.5 SCCDA is a continuous improvement process. Through successive applications, SCCDA should identify and address locations where SCC has occurred, is occurring, or might occur.

1.1.5.1 SCCDA provides the advantage and benefit of indicating areas where SCC might occur in the future rather than only areas where SCC is known to exist.

1.1.5.2 Comparing the results of successive SCCDA applications is one method of evaluating SCCDA effectiveness and demonstrating that confidence in the integrity of the pipeline is continuously improving.

1.1.6 SCCDA was developed as a process for improving pipeline safety. Its primary purpose is to reduce the threat of external SCC on pipeline integrity by means of condition monitoring, mitigation, documentation, and reporting.

1.1.6.1 This standard assumes SCC is a threat to be evaluated. It can be used to establish a baseline from which future SCC can be assessed for pipelines on which SCC is not currently a significant threat.

1.1.7 SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. SCCDA also is complementary with other direct assessment procedures such as those given in NACE SP0206.[3]

1.1.7.1 ILI or hydrostatic testing might not be warranted if the initial SCCDA assessment indicates that significant and extensive cracking is not present on a pipeline system.

1.1.7.2 SCCDA can be used to prioritize a pipeline system for ILI or hydrostatic testing if significant and extensive SCC is found.

1.1.8 SCCDA may detect other pipeline integrity threats, such as mechanical damage, external corrosion, etc. When such threats are detected, additional assessments or inspections shall be performed. The pipeline operator shall utilize appropriate methods such as ASME B31.8S,[1] ASME B31.4,[4] ASME B31.8,[5] API[(2)] 1160,[6] NACE standards, international standards, and other documents to address risks other than external SCC.

1.1.9 SCCDA can be applied to most onshore petroleum pipelines, regardless of the coating system. Precautions should be taken when applying these techniques just as with other assessment methods.

1.1.10 Given the diversity of pipelines and their operation, this standard recognizes that SCCDA may be inappropriate for some situations because of the complexity of conditions to which buried pipeline systems are exposed.

1.1.11 The provisions of this standard shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering, geosciences, and mathematics, acquired by education and related practical experience, are qualified to engage in the

(2) American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005.

practice of corrosion control, integrity management, and risk assessment on buried steel pipeline systems.

1.2 Relationship Between SCCDA Process and SCC Integrity Management

1.2.1 Initial selection of pipeline segments for assessment of risk of high-pH SCC on gas pipelines should be based on Part A3 of ASME B31.8S,[1] Section A3.3. Part A3 considers the following factors: operating stress, operating temperature, distance from compressor station, age of pipeline, and coating type.[(3)] It is recognized that these screening factors will identify a substantial percentage of the susceptible locations, but not necessarily all of them.

1.2.1.1 A pipeline segment is considered susceptible to high-pH SCC if all of the following factors are met.

1.2.1.1.1 The operating stress exceeds 60% of specified minimum yield strength (SMYS);

1.2.1.1.2 The operating temperature exceeds 38 °C (100 °F);

1.2.1.1.3 The segment is less than 32 km (20 mi) downstream from a compressor station;

1.2.1.1.4 The age of the pipeline is greater than 10 years; and

1.2.1.1.5 The coating type is other than fusion-bonded epoxy.

1.2.1.2 ASME B31.8S addresses gas pipelines, but the same factors and approach generally can be used for liquid petroleum pipelines, considering the distance downstream from a pump station as one of the factors for selecting potentially susceptible segments.

1.2.2 Part A3 of ASME B31.8S does not currently address near-neutral-pH SCC. The same factors and criteria can be used for the selection of pipeline segments for assessment of risk of near-neutral-pH SCC, with the exclusion of the temperature criterion.

1.2.3 This standard provides guidance for Part 3.4 of ASME B31.8S on prioritization of potentially susceptible segments, dig site selection within the potentially susceptible segments, dig site verification, inspection of the pipe at a dig site, data collection at the dig site, and subsequent data analysis.

1.2.4 Part A3 of ASME B31.8S provides guidance for integrity management decisions for SCC based on the collected data.

1.3 Four-Step SCCDA Process

1.3.1 The SCCDA process consists of four steps: Pre-Assessment, Indirect Inspections, Direct Examinations, and Post Assessment.

1.3.1.1 Pre-Assessment. In the *Pre-Assessment Step*, historic and currently available data are collected and analyzed to prioritize the segments within a pipeline system with respect to potential susceptibility to SCC and to select specific sites within those segments for direct examinations. The types of data to be collected are typically available from in-house construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, government sources, and inspection reports from prior integrity evaluations or maintenance actions.

1.3.1.2 Indirect Inspections. In the *Indirect Inspection Step*, additional data are collected, as deemed necessary by the pipeline operator, to aid prioritization of segments and in site selection. The necessity to conduct indirect inspections and the nature of these inspections depends on the nature and extent of the data obtained in the Pre-assessment Step and the data needs for site selection. Typical data collected in this step might include close-interval survey (CIS) data, direct current voltage gradient (DCVG) data, and information on terrain conditions (soil type, topography, and drainage) along the right of way.

1.3.1.3 Direct Examination. The *Direct Examination Step* includes procedures to field verify the sites selected in the first two steps, and to conduct the field digs. Aboveground measurements and inspections are performed to field verify the factors used to select the dig sites. For example, the presence and severity of coating faults might be confirmed. If predictive models based on terrain conditions are used, the topography, drainage, and soil type require verification. The digs are then performed; the severity, extent, and type of SCC, if any is detected, at the individual dig sites are assessed; and data that can be used in post assessment and predictive-model development are collected.

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(3) These selection criteria for SCC-susceptible segments are based on the criteria in the most recent edition of ASME B31.8 in effect at the time of publication of the 2004 edition of RP0204. If the criteria are revised in future revisions of ASME B31.8, the criteria used in this standard shall remain unchanged.

1.3.1.4 Post Assessment. In the *Post-Assessment Step*, data collected from the previous three steps are analyzed to determine whether SCC mitigation is required, and if so, to prioritize those actions; to define the interval to the next full integrity reassessment; and to evaluate the effectiveness of the SCCDA approach.

1.3.1.5 A flow chart for the SCCDA process is shown in Figure 1.

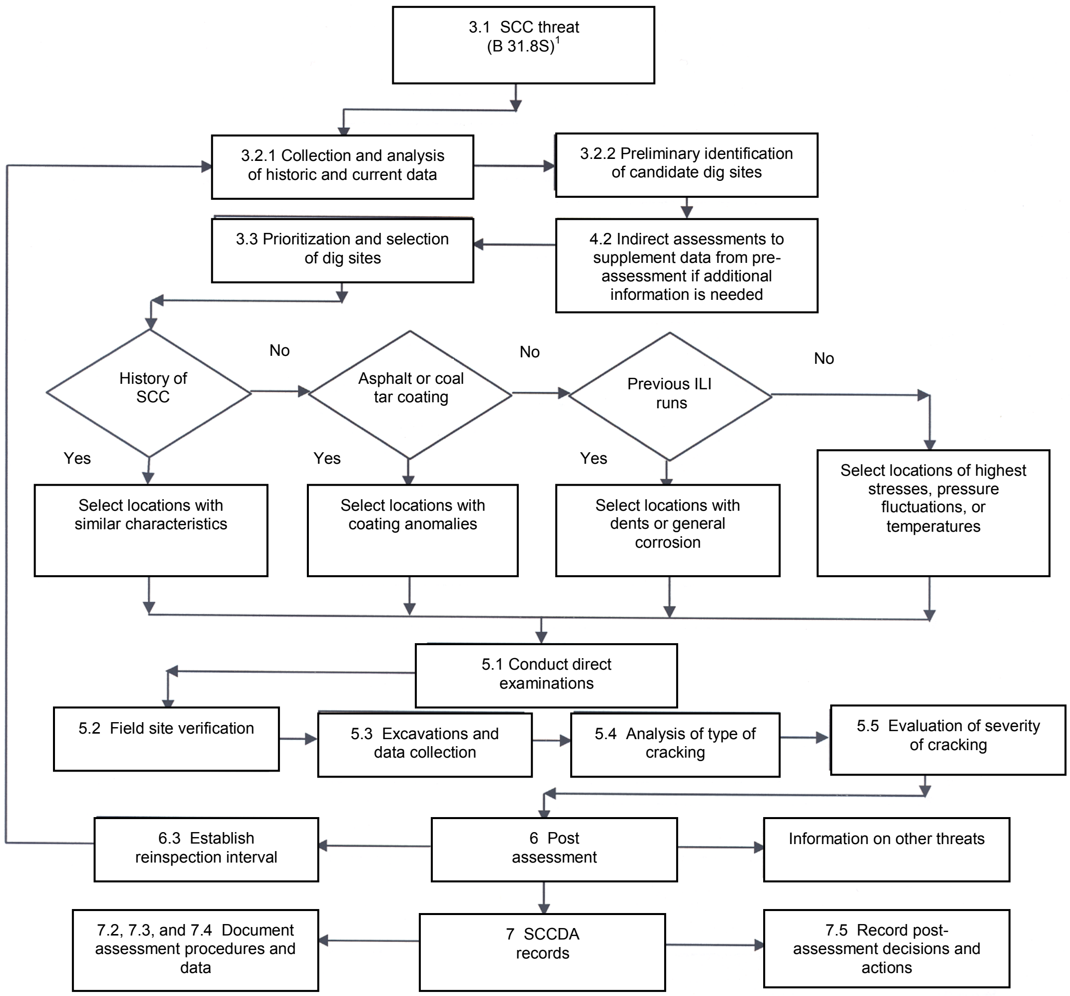

Figure 1: Flow Chart for SCCDA Process
(Numbers refer to paragraph numbers in this standard.)

Section 2: Definitions

For the purposes of this standard, the following definitions apply.

Aerobic: Oxygen-containing.

Active: (1) The negative direction of electrode potential. (2) A state of a metal that is corroding without significant influence of reaction product.

Anaerobic: Free of air or uncombined oxygen.

Anomaly: Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

Aspect Ratio: Ratio of crack length to crack depth.

Asphalt Coating: Asphalt based anti-corrosion coating.

B31G[7]: A method (from the ASME standard) of calculating the pressure-carrying capacity of a corroded pipe.

Black on White Magnetic Particle Inspection (BWMPI): A magnetic particle inspection (MPI) technique that uses a suspension of black magnetic iron particles that are applied on a white painted pipeline surface in the presence of a magnetic field.

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Cathodic Protection (CP): A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

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.

Classical SCC: A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3). Also referred to as high-pH SCC.

Close-Interval Survey (CIS) (Also Close-Interval Potential Survey [CIPS]): A series of pipe-to-electrolyte potentials performed on a buried or submerged metallic pipeline, obtaining valid direct current (DC) structure-to-electrolyte potentials directly over the structure at a regular interval sufficiently small to perform a detailed assessment.

Cluster: A grouping of stress corrosion cracks (colony). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area.

Coal Tar Coating: Coal tar-based anti-corrosion coating.

Coating System: The complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.)

Colony: A grouping of stress corrosion cracks (cluster). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area. See *Cluster*.

Collinear: Lying along the same line (coaxial). A term used to describe spatial relationship of adjacent cracks.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Crack Coalescence: Joining of cracks that are in close proximity to form one larger crack.

Critical Flaw Size: The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.

Defect: An anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.

Dent: A depression caused by mechanical means that produces a visible disturbance in the curvature of the wall of the pipe or component without reducing the wall thickness.

Discrete Repair: Repair of a short segment of a pipeline.

Direct Current Voltage Gradient (DCVG): A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

Direct Examination: Inspections and measurements made on the pipe surface at excavations as part of direct assessment.

Disbonded Coating: Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday. See also *Cathodic Disbondment*.

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.

ECDA: See *External Corrosion Direct Assessment (ECDA).*

Electric Resistance Weld (ERW): A method of welding the long seam of a pipe during manufacture in which the two sides of the seam are first heated by the application of an electrical current and then forced together to form a bond.

Electrolyte: A chemical substance containing ions that migrate in an electric field. For the purposes of this standard, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic pipeline system, including the moisture and other chemicals contained therein.

External Corrosion Direct Assessment (ECDA): A four-step process that combines pre-assessment, indirect inspections, direct examinations, and post assessment to evaluate the impact of external corrosion on the integrity of a pipeline.

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.

Fault: Any anomaly in the coating, including disbonded areas and holidays.

Fracture Toughness: A measure of a material's resistance to static or dynamic crack extension. A material's property used in the calculation of critical flaw size for crack-like defects.

Girth Weld: The circumferential weld that joins two sections of pipe.

Gouge: A surface imperfection caused by mechanical damage that reduces the wall thickness of a pipe or component.

Heat-Affected Zone (HAZ): That portion of the base metal that is not melted during brazing, cutting, or welding, but whose microstructure and properties are altered by the heat of these processes.

High-pH SCC: A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3). Also referred to as classical SCC.

Holiday: A discontinuity in a protective coating that exposes unprotected surface to the environment.

Hoop Stress: Circumferential stress in a pipe or pressure vessel that results from the internal pressure.

Hydrostatic Testing: Pressure testing of sections of a pipeline by filling it with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

Indication: Any deviation from the norm as measured by an indirect inspection tool.

Indirect Inspection: Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize corrosion activity, coating holidays, or other anomalies.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipe using an ILI tool. Also called intelligent or smart pigging.

ILI Tool: An instrumented device or vehicle that uses a nondestructive testing technique to inspect the pipeline from the inside or that uses sensors and other equipment to measure one or more characteristics of the pipeline. Also known as intelligent or smart pig.

Intergranular Cracking: Cracking in which the crack path is between the grains in a metal (typically associated with high-pH SCC).

Investigative Dig: An inspection of a pipeline at a discrete location exposed for examination.

Leak: Product loss through a small hole or crack in the pipeline.

Low-pH SCC: See *Near-Neutral-pH SCC.*

Magnetic Particle Inspection (MPI): A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field. See also ASTM(4) E 709.[8]

Maximum Allowable Operating Pressure (MAOP): The maximum internal pressure permitted during the operation of a pipeline.

Mechanical Damage: Anomalies in pipe—including dents, gouges, scratches, and metal loss—caused by the application of an external force.

Metallography: The study of the structure and constitution of a metal as revealed by a microscope.

Microbiologically Influenced Corrosion (MIC): A form of corrosion that results from certain microbes and nutrients in the soil.

Mill Scale: The oxide layer formed during hot fabrication or heat treatment of metals.

Miter Bend: Early pipeline construction practice for changing the direction of (bending) a pipeline by making cuts in adjacent segments of pipe at an angle other than 90° (with respect to the pipe axis) and welding the segments together.

Near-Neutral-pH SCC: A form of SCC on underground pipelines that is transgranular and is associated with a near-neutral-pH electrolyte. Typically this form of cracking has

(4) ASTM International (ASTM), 100 Barr Harbor Drive, West Conshocken, PA 19428-2959.

limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as low-pH or nonclassical SCC.

pH: The negative logarithm of the hydrogen ion activity written as:

$$pH = -\log_{10} (a_H^+)$$

where a_H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion-activity coefficient.

Pipe-to-Electrolyte Potential: See *Structure-to-Electrolyte Potential.*

Pipe-to-Soil Potential: See *Structure-to-Electrolyte Potential.*

Predictive SCC Model: A model that predicts the SCC susceptibility of a segment of a pipeline based on factors such as terrain conditions (topography, drainage, and soil type), pipe characteristics, and operating and maintenance history.

Pressure: A measure of force per unit area.

Remediation: As used in this standard, remediation refers to corrective actions taken to mitigate SCC.

Residual Stress: The locked-in stress present in an object that results from the manufacturing process, heat treatment, or mechanical working of the material.

Rupture: A failure of a pipeline that results from fracture propagation and causes an uncontrolled release of the contained product.

RSTRENG[9]: A computer program designed to calculate the pressure-carrying capacity of corroded pipe.

SCCDA: The stress corrosion cracking direct assessment process.

Segment: A portion of a pipeline that is (to be) assessed using SCCDA.

Shielding: (1) Protecting; protective cover against mechanical damage. (2) Preventing or diverting cathodic protection current from its natural path.

Shot Peening: Inducing compressive stresses in the surface layer of a material by bombarding it with a selected medium (usually steel shot) under controlled conditions.

Significant SCC: An SCC cluster was defined to be significant by the Canadian Energy Pipeline Association (CEPA)[(5)] in 1997 provided that the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria.[(6)] The presence of extensive and significant SCC typically triggers an SCC mitigation program (see discussion under *Post-Assessment Step*), but a crack that is labeled "significant" is not necessarily an immediate threat to the integrity of the pipeline.

Specified Minimum Yield Strength (SMYS): The minimum yield strength of a material prescribed by the specification or standard to which the material is manufactured.

Stress: The force per unit area when a force acts on a body.

Stress Corrosion Cracking (SCC): Cracking of a material produced by the combined action of corrosion and tensile stress (residual or applied).

Structure-to-Electrolyte Potential: The 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.

Subcritical Crack: A crack that is not large enough to cause spontaneous failure at a specific pressure or stress.

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. Often used as input in the generation of SCC predictive models.

Transgranular Cracking: Cracking in which the crack path is through the grains of a metal (typically associated with near-neutral-pH SCC).

Voltage: An electromotive force or a difference in electrode potentials, commonly expressed in volts or millivolts.

Wet Fluorescent MPI (WFMPI): An MPI technique that uses a suspension of magnetic particles that are fluorescent and visible with an ultraviolet light.

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(5) Canadian Energy Pipeline Association (CEPA), 1650, 801 6th Avenue SW, Calgary, Alberta, Canada T2P 3W2.
(6) The definitions of "significant SCC" and "interaction criteria for cracks" are based on the definitions in the most recent edition of the CEPA SCC Recommended Practices Manual in effect at the time of the publication of the 2004 edition of RP0204. If the definitions of these terms are revised in future editions of the CEPA SCC Recommended Practices Manual, the definitions used in this standard shall remain unchanged.

Wet Visual MPI (WVMPI): An MPI technique that uses a suspension of magnetic particles that are visible with natural light.

Wrinkle Bend: Early pipeline construction practice for changing the direction of (bending) a pipeline in which localized buckles are introduced in the intrados of the bend.

Yield Strength: The stress at which a material exhibits a specified deviation from the proportionality of stress to strain. The deviation is expressed in terms of strain by either the offset method (usually at a strain of 0.2%) or the total-extension-under-load-method (usually at a strain of 0.5%.)

Section 3: Pre-Assessment

3.1 Introduction

3.1.1 The objective of the Pre-Assessment Step is to collect and analyze historic and current data to prioritize potentially susceptible segments of pipelines and help select specific sites for excavation within those segments. The susceptible segments for high-pH SCC have been identified based on the criteria in Part A of ASME B31.8S,[1] as listed below. Similar criteria, except the one regarding operating temperature, may be used for near-neutral-pH SCC. It is recognized that these screening factors will identify a substantial percentage of the susceptible locations, but not necessarily all of them.

3.1.1.1 A pipeline segment is considered to be susceptible to high-pH SCC if all of the following factors are met:

3.1.1.1.1 The operating stress exceeds 60% of the SMYS;

3.1.1.1.2 The operating temperature has historically exceeded 38 °C (100 °F);

3.1.1.1.3 The segment is less than or equal to 32 km (20 mi) downstream from a compressor station;

3.1.1.1.4 The age of the pipeline is greater than or equal to 10 years; and

3.1.1.1.5 The coating type is other than fusion-bonded epoxy (FBE).

3.1.1.2 ASME B31.8S addresses gas pipelines, but the same factors and approach generally can be used for liquid petroleum pipelines, considering the distance downstream from a pump station as one of the factors for selecting potentially susceptible segments.

3.1.2 Part A3 of ASME B31.8S does not currently address near-neutral-pH SCC. The same factors and criteria can be used for the selection of pipeline segments for assessment of risk of near-neutral-pH SCC, with the exclusion of the temperature criterion.

3.1.3 The Pre-Assessment Step requires a sufficient amount of data collection, integration, and analyses. The Pre-Assessment Step must be performed in a comprehensive and thorough fashion.

3.1.4 The Pre-Assessment Step includes the following activities:

3.1.4.1 Data collection and prioritization of susceptible segments.

3.1.4.2 Initial identification of candidate sites for additional indirect surveys and subsequent direct examinations.

3.2 Data Collection and Segment Prioritization

3.2.1 The pipeline operator shall collect historical and current data along with physical information for the segment to be evaluated.

3.2.1.1 The pipeline operator shall define minimum data requirements based on the history and known condition of the pipeline segment. In addition, the pipeline operator shall consider data elements identified, for example, by other direct assessment practices, the Pipeline Research Council, Inc. (PRCI),[(7)] or CEPA that may enhance the success of the SCCDA process.

3.2.1.2 All parameters that impact the probability of SCC in a certain region shall be considered for initial SCCDA process applications on a pipeline segment.

3.2.2 As a minimum, the pipeline operator shall include data from the following five categories, as shown in Table 1. The data elements were selected to provide guidance on the types of data to be collected

[(7)] Pipeline Research Council International, Inc. (PRCI), 1401 Wilson Boulevard, Suite 1101, Arlington, VA 22209.

for SCCDA. Not all items in Table 1 are necessary for the entire pipeline. In addition, a pipeline operator may determine that items not included in Table 1 are necessary.

Table 1
Factors to Consider in Prioritization of Susceptible Segments and in Site Selection for SCCDA

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
PIPE RELATED			
Grade	No known correlation with SCC susceptibility.	Background data needed to calculate stress as percent of SMYS.	C
Diameter	No known correlation with SCC susceptibility.	Background data needed to calculate stress from internal pressure.	C
Wall thickness	No known correlation with SCC susceptibility.	Impacts critical defect size and remaining life predictions. Needed to calculate stress from internal pressure.	C
Year manufactured	No known correlation with SCC susceptibility.	Older pipe materials typically have lower toughness levels, reducing critical defect size and remaining life predictions.	C
Pipe manufacturer	Near-neutral-pH SCC has been found preferentially in the HAZ of ERW pipe that was manufactured by Youngstown Sheet and Tube in the 1950s. Reported to be statistically significant predictor for near-neutral-pH SCC in system model for one pipeline system.	Important factor to consider for near-neutral-pH SCC.	A
Seam type	Near-neutral-pH SCC has been found preferentially under tented tape coatings along DSAW and in HAZ along some ERW. No known correlation with high-pH SCC.	May be important factor to consider for near-neutral-pH SCC.	B
Surface preparation	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high-pH SCC.[5]	Important factor to consider for both high-pH and near-neutral-pH SCC.	A
Shop coating type	To date, SCC has not been reported for pipe with undamaged FBE coating or with extruded polyethylene coating.	Important factor to consider for both high-pH and near-neutral-pH SCC.	A
Bare pipe	SCC has been observed on bare pipe in high-resistivity soils.	May be important factor.	B
Hard spots	There have been instances in which near-neutral-pH SCC has occurred preferentially in hard spots, which can be located by ILI that measures residual magnetism.	May be important factor.	B
CONSTRUCTION RELATED			
Year installed	Impacts time over which coating degradation may occur and cracks may have been growing.	Age of pipeline used in criteria for selection of susceptible segments in Part A3 of ASME B31.8S.[1]	A
Route changes/modifi-cations	No known correlation to SCC.	May be important for accurately locating each site.	C
Route maps/aerial photos	No known correlation to SCC.	May be important for accurately locating each site.	C

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
Construction practices	Backfill practices influence probability of coating damage during construction. Also, time between burying of pipe and installation of CP might be important.	Early levels of CP might be important.	B
Surface preparation for field coating	Mill scale promotes potential in critical range for high-pH SCC.	May be discriminating factor.	A
Field coating type	High-pH SCC found under coal tar, asphalt, and tape. Near-neutral-pH SCC most prevalent under tape but also found under asphalt. Weather conditions during construction also may be important in affecting coating condition.	Important factor to consider for near-neutral-pH SCC.	A
Location of weights and anchors	Near-neutral-pH SCC has been found under buoyancy-control weights.	Might be important, especially for near-neutral-pH SCC.	B
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and isolating joints	No known relation to SCC. Just applicable to locating and characterizing sites.	May be important for accurately locating and characterizing each site.	C
Locations of casings	CP shielding and coating damage more likely within casings.	May be important for accurately locating and characterizing each site.	B
Locations of bends, including miter bends and wrinkle bends	Might indicate unusual residual stresses.	Residual stress may be an important factor.	B
Location of dents	Might indicate unusual residual stresses.	Residual stress may be an important factor.	B
SOILS/ENVIRONMENTAL			
Soil characteristics/ types (Refer to Appendix A [non-mandatory].)	No known correlation between soil type and high-pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. Some success has been experienced in correlating near-neutral-pH SCC with specific soil types.	Might be important, especially for near-neutral-pH SCC.	B
Drainage	Has been correlated with both high-pH and near-neutral-pH SCC.	Might be important parameter.	B
Topography	Has been correlated with both high-pH and near-neutral-pH SCC, possibly related to effect on drainage. Also, circumferential near-neutral-pH SCC has been observed on slopes where soil movement has occurred.	Might be important parameter.	B
Land use (current/past)	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings.	Might be important parameter.	B
Groundwater	Groundwater conductivity affects the throwing power of CP systems.	Might be important parameter.	B
Location of river crossings	Affects soil moisture/drainage.	Might be important parameter.	B

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Important parameter.	B
CP evaluation criteria	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Background information.	C
CP maintenance history	Adequate CP can prevent SCC if it reaches under disbonded coatings.	Background information.	C
Years without CP applied	For high-pH SCC, absence of CP might allow harmful oxides to form on pipe surface. For near-neutral-pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed.	Important parameter.	B
CIS and test station information	Although high-pH SCC occurs in a narrow range of potentials (typically between –575 and –825 mV vs. copper/copper sulfate [$Cu/CuSO_4$] depending on temperature and solution composition), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential at the pipe surface can be less negative than the aboveground measurements because of shielding by disbonded coatings. Nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past.	Important factor to consider for both high-pH and near-neutral-pH SCC.	B
Coating fault survey information	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	B
Coating system and condition	The coating system (coating type, surface condition, etc.) is an important factor in determining SCC susceptibility and the type of SCC that occurs. Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information.	A
OPERATIONAL DATA			
Pipe operating temperature	Elevated temperatures have strong accelerating effect on high-pH SCC. For near-neutral-pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.	Important, especially for high-pH SCC.	A
Operating stress levels and fluctuations	Stress must be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.	Impacts SCC initiation, critical flaw size, and remaining life predictions.	A
Leak/rupture history (SCC)	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
Direct inspection and repair history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
Hydrostatic retest history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A
ILI data from crack-detecting pig	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important.	A

Factor	Relevance to SCC	Use and Interpretation of Results	Ranking
ILI data from metal-loss pig	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC, especially near-neutral-pH SCC, has been observed.	May be important.	B

The relative importance of each data element (indicated in last column) is:
A. Usually important for prioritizing sites.
B. May be important for prioritizing sites in some cases.
C. Not relevant to prioritizing, but may be useful for record keeping.

3.2.2.1 Pipe Related

3.2.2.1.1 For mill-coated pipe, surface preparation and coating type are the most relevant pipe-related factors. The type of seam weld also may be significant.

3.2.2.2 Construction Related

3.2.2.2.1 For pipe coated over the ditch, surface preparation, coating type, and weather conditions are the most relevant construction-related factors. Anything that would contribute to residual stresses also may be important.

3.2.2.3 Soils/Environmental

3.2.2.3.1 In some cases, moisture content and soil type have been correlated with locations of SCC (see discussion in Appendix A and the CEPA Stress Corrosion Cracking Recommended Practices Manual[10]).

3.2.2.4 Corrosion Protection

3.2.2.4.1 Adequate CP can prevent SCC except under disbonded coatings, which might shield the current from the pipe.

3.2.2.5 Pipeline Operations

3.2.2.5.1 SCC history and pressure fluctuations are important. Temperature history also is important for high-pH SCC.

3.2.2.5.2 For liquid lines, changes in product can influence operating conditions, such as the pressure profile between pumping stations.

3.2.3 The data collected in the Pre-Assessment Step often include the same data typically considered in an overall pipeline risk (threat) assessment. Depending on the pipeline operator's integrity-management plan and its implementation, the operator may conduct the Pre-Assessment Step in conjunction with a general risk assessment effort.

3.2.4 When data for a particular category are not available, conservative assumptions based on the operator's experience and information about similar systems shall be used. The basis for these assumptions and the resulting decisions shall be documented.

3.2.5 In the event that the pipeline operator determines that sufficient data are not available or cannot be collected for some SCCDA regions comprising a segment to support the Pre-Assessment Step, SCCDA shall not be used for those SCCDA regions until appropriate data can be obtained.

3.3 Selection of Dig Sites in Susceptible Segments

3.3.1 If additional information is desired or needed, this step should be delayed until an indirect assessment, as described in Section 4, is completed.

3.3.2 Ideally, the dig sites should be selected to maximize the probability of finding SCC if it does exist on the pipe. Unfortunately, there are no well-established methods for predicting with a high degree of certainty the presence of SCC, based on aboveground measurements. However, industry experience can provide some guidance for selecting more probable sites. The critical factors for high-pH SCC and near-neutral-pH SCC are similar, but some differences may exist. Also, the most relevant factors may differ from one pipeline to another or even one segment to another, depending on the history of the line. Some companies have found that predictive models can be effective at identifying and ranking areas along a pipeline that are susceptible to near-neutral-pH SCC. Such models can be effective only if reliable pipe and terrain conditions are used and the predictive model is verified and enhanced through investigative excavations. The following section lists the factors to be considered in order of their reliability for locating SCC, and they shall be used in the order indicated unless insight is available to support proceeding otherwise.

3.3.3 Factors to Consider in Selecting Sites to Dig

3.3.3.1 If there is a history of SCC in the area of interest (e.g., service failures, hydrostatic test failures, ILI indications, or previous digs), digging should take place near the previous locations of SCC. Industry experience indicates that there is a high probability of SCC occurring near other places where it has been found.

3.3.3.2 If previous SCC locations have been associated with unique characteristics of the pipe, digging should take place in other areas with those same characteristics. Some pipeline companies have found correlations with areas of mechanical damage such as dents; geophysical features such as soil moisture, drainage, or soil type (see Appendix A); steep slopes with soil subsidence; or coating anomalies.

3.3.3.3 If there is no history of SCC in the area of interest, locations with coating anomalies should be considered. For coatings such as coal tar or asphalt, these areas might be identified from a CIS or a coating-fault survey.

3.3.3.3.1 NACE SP0207[11] contains recommended practices for CIS.

3.3.3.3.2 NACE TG 294[12] is developing recommended practices for coating-fault surveys. Until they are available, procedures as described in Appendix A of NACE SP0502[13] may be used.

3.3.3.4 If ILI tools for features such as geometry or metal loss have been run in pipe with coatings that may shield the pipe and there is no history of SCC in the area, locations of dents or general corrosion should be considered because both features have sometimes been associated with SCC.

3.3.3.5 In the absence of any other suitable indicators, locations where the stresses, pressure fluctuations, and temperatures were highest or where there has been a history of coating deterioration should be selected.

3.3.3.6 For subsequent digs in the same area, sites that have the same unique features that were revealed in earlier digs, if there were any, should be selected. If not, other areas where stresses, pressure fluctuations, and temperatures were relatively high should be selected.

3.3.3.7 It is critical to ensure that an exposed joint of pipe corresponds to the one that contained an ILI indication. The identity of the joint can be confirmed by comparing the measured distance between girth welds, the circumferential position of the longitudinal seam weld, and the location of aboveground markers with the indications on the ILI log.

Section 4: Indirect Inspections

4.1 Introduction

4.1.1 The objectives of the Indirect Inspection Step are to conduct aboveground or other types of measurements to supplement the data from the pre-assessment, if additional information is needed, and then to use these data to prioritize susceptible segments and select the specific sites for direct examination.

4.1.2 The nature of the data collected in this step depends on the extent and quality of the data collected in the Pre-Assessment Step.

4.2 Types of Measurements to Consider

4.2.1 Aboveground measurements might include activities such as CIS, coating-fault surveys, or additional geological surveys and characterization.

4.2.1.1 NACE SP0207 contains recommended practices for CIS.

4.2.1.2 Recommended practices for coating-fault surveys are being developed by TG 294. Until they are available, procedures as described in Appendix A of NACE SP0502 may be used.

4.2.2 Other types of data that might be obtained in this step include:

4.2.2.1 Locations of dents and bends, found with ILI geometry tools, on pipelines in which the SCC has been associated with such features.

4.2.2.2 Areas of coating disbondment and corrosion, located by ILI magnetic-flux-leakage (MFL) tools, on pipelines in which the SCC has been associated with such features.

Section 5: Direct Examinations

5.1 Introduction

5.1.1 The objectives of the Direct Examination Step are (1) to examine the pipe at locations chosen after the Pre-Assessment Step and, if applicable, the indirect examination and (2), if SCC is detected, to assess the presence, extent, type, and severity of SCC at the individual dig sites. If desired, data can be collected to be used in post assessment for development or refinement of a predictive model.

5.1.2 The types and extent of data collected at the dig sites are at the discretion of the pipeline operator and depend on the planned usages of the data. A listing of the types of data to consider is given in Table 2.

5.1.2.1 Limited data, consisting of the assessment of cracking, might be appropriate in cases in which the operator is assessing a pipeline segment for the presence or absence of SCC.

5.1.2.2 More extensive data collection procedures would be required if the operator is attempting to develop a predictive model for SCC on a pipeline system.

5.1.2.3 If cracks are found, the crack dimension data used to establish serviceability of the pipeline shall be recorded.

5.1.3 The Direct Examination Step requires excavations to expose the pipe surface so that measurements can be made directly on the pipeline and in the immediate surrounding environment at pipe depth.

5.1.4 The order in which excavations and direct examinations are made is at the discretion of the pipeline operator but should take into account safety and related considerations (see Section 4 on prioritization).

5.1.5 During the Direct Examination Step, defects other than SCC might be found. Alternative methods must be considered for assessing such defect types. Alternative methods are given in ASME B31.8S,[1] ASME B31.4,[4] ASME B31.8,[5] API 1160,[6] NACE standards, international standards, and other documents.

5.1.6 The Direct Examination Step includes the following activities:

5.1.6.1 Verification of the field sites selected based on the Pre-Assessment and Indirect Examination Steps.

5.1.6.2 Excavation and data collection at the field sites.

5.1.6.3 Analysis and documentation of the type of cracking if SCC is detected.

5.1.6.4 Evaluation and documentation of the severity of cracking if SCC is detected.

Table 2
Data Collected at a Dig Site in an SCCDA Program and Relative Importance

Data Element	When Collected	Use and Interpretation of Results	Ranking
Pipe-to-soil potential	Prior to coating removal.	Useful for comparison with ground surface pipe-to-soil potential measurements.	D
Soil resistivity	Prior to coating removal.	Related to soil corrosiveness and soluble cation concentration of soil. Useful for comparison with results of soil and groundwater analyses.	C
Soil samples	Prior to coating removal.	Useful in confirming terrain conditions. Soil analysis results can be trended in predictive model.	B
Groundwater samples	Prior to coating removal.	Chemistry results can be trended in predictive model.	B
Coating system	Prior to coating removal.	Required element. Used for field site verification and in predictive model development.	A
Coating condition	Prior to coating removal.	Can be related to extent of SCC found.	C
Measurement of coating disbondment	Prior to coating removal.	Locations of disbondment can be related to presence of cracking and other measured data.	C
Electrolyte	Prior to coating removal.	Useful in establishing type of cracking. Can be related to groundwater chemistry.	C

Data Element	When Collected	Use and Interpretation of Results	Ranking
Photograph of dig site	Prior to coating removal.	Useful in confirming terrain conditions, coating system, and coating condition.	D
Data for other integrity analyses	Before and after coating removal.	Data for other analyses (e.g., dent measurements) may be related to occurrence of SCC.	C, D
Deposit description and photograph	After coating removal.	Useful in establishing type of cracking.	C
Deposit analysis	After coating removal.	Useful in establishing type of cracking.	C
Identification and measurement of corrosion defects	After coating removal.	Used for integrity assessment of corrosion defects. Also used in establishing type of SCC, if present.	A, D
Photograph of corrosion defects	After coating removal.	Used in integrity assessments.	D
Identify weld seam type	After coating removal.	Required element. Used in field site verification.	A
MPI	After coating removal.	Required element for SCCDA. Establishes whether SCC is present.	A
Location and size of each cluster	After coating removal.	Required element for SCCDA. Used to establish correlation of location with other parameters measured.	A
Crack length and depth measurements	After coating removal.	Required element for SCCDA. Used to establish significance of cracking and determine whether there is an immediate integrity concern.	A
In situ metallography	After coating removal.	Used to establish type of SCC.	B
Photograph clusters	After coating removal.	Required element for SCCDA. Used to confirm crack measurements.	A
Wall thickness measurements	After coating removal.	Required element. Used in integrity assessments and field site verification.	A, D
Measure pipe diameter	After coating removal.	Required element. Used in integrity assessments and field site verification.	A, D

The relative importance of each data element (indicated in last column) is:
A: Required element for SCCDA.
B: Optional (likely useful in SCCDA model development).
C: Optional (might be useful in SCCDA model development).
D: Useful background information or information used in other analyses.

5.2 Field Site Verification

5.2.1 Prior to beginning excavation, the aboveground parameters used for the dig site selection shall be field verified. The nature of these parameters depends on the selection criteria used.

5.2.2 When pipeline construction data, a terrain-based predictive model, or other data are used for site selection, the actual conditions shall be field verified. The topography normally is confirmed through visual observation. The soil and drainage can be confirmed by hand augering.

5.2.2.1 Appendix A and the CEPA Stress Corrosion Cracking Recommended Practices Manual[10] provide guidance on soils characterization for near-neutral-pH SCC.

5.2.3 When site selection is based on the presence of coating faults or areas of potential corrosion activity—identified by techniques such as DCVG or CIS—the location shall be field verified by measurement from a known reference point identified during the survey or by repeating the measurements in the area of the planned dig site.

5.2.3.1 NACE SP0502[13] provides guidance on DCVG and CIS techniques.

5.2.4 When ILI data are used for dig site selection, the location of the dig site with respect to aboveground features on the pipeline such as aboveground markers, valves, or casings/casing vents shall be field verified and compared with the ILI data.

5.3 Excavations and Data Collection

5.3.1 The pipeline operator should select a reference location for each excavation so that data can be recorded in an organized fashion and inspection and direct examination results can be directly compared.

5.3.2 Before conducting excavations, the pipeline operator shall define minimum requirements for consistent data collection and record-keeping requirements. Minimum requirements shall be based on the pipeline operator's judgment and may depend on characteristics including operation of the pipeline, the pipeline network, or the specific location. Guidance is provided in Table 2.

5.3.2.1 Minimum requirements should include the types of data to be collected and take into account the conditions to be encountered, the planned uses for the data, and the availability and quality of prior data.

5.3.3 Data Collection—Prior to Coating Removal

5.3.3.1 The pipeline operator shall identify important data to be taken during each excavation, before coating removal, and after excavation. Data measurements and related activities that might be useful are listed below. The Stress Corrosion Cracking Recommended Practices Manual[10] and Appendixes A and B of NACE SP0502[13] on ECDA contain additional information on the types of data that can be obtained, their uses, and the measurement techniques.

5.3.3.2 Measurement of pipe-to-soil potentials. Pipe-to-soil potentials are commonly measured immediately following pipe excavation by placing a reference electrode in the bank of the excavation around the pipe at both ends of the excavation. With the use of interrupters, both on- and off-potentials can be obtained. Typically, these data are used to aid in assessing the level of CP at the pipe. Caution should be used in interpreting the results of these measurements because the excavation of the pipe alters the electric field in the soil around the pipe.

5.3.3.3 Measurement of soil resistivity. Soil resistivity measurements are used to assess the corrosiveness of the soil, which can be related to the concentration of soluble ions in the soil and soil moisture content. The two most common methods for measuring soil resistivity are the Wenner Four Pin Method and the Soil Box Method.[13]

5.3.3.4 If a predictive model is being employed or developed, soil and groundwater sample collection may be useful. The main purpose of collecting soil and groundwater samples is to further develop an understanding of the environmental factors associated with SCC. Parameters such as soil mineralogy and soil texture can influence the level of oxygenation (aerobic versus anaerobic), the soil drainage, and the tendency to promote coating disbondment. The general chemistry and biological parameters can be input in predictive models for SCC. Examples of chemical parameters that are analyzed include pH, conductivity, cation and anion concentration, oxidation-reduction potentials, total carbonates, and organic carbon. All analyses for soil, groundwater, mineralogy, and soil textures shall follow standardized sampling, storage, transportation, and laboratory procedures, which shall be established by each operating company. (See discussion in Section 7 of the CEPA Stress Corrosion Cracking Recommended Practices Manual.[10])

5.3.3.5 Assessment of the coating system. The type of coating should be identified based on visual observation and recorded. If possible, also determine other characteristics of the coating system, such as the type of surface preparation, whether shop coated or over-the-ditch coated, type of primer, number of coats, reinforcement, and outer wrap. If the type cannot be positively identified, a coating sample should be obtained and analyzed. Analysis of the coating can provide information pertaining to type as well as electrical and physical properties (e.g., resistivity, gas permeability, etc.). The samples can also be used to conduct microbial tests.

5.3.3.6 Assessment of overall coating condition. The overall coating condition and extent of coating disbondment should be assessed and recorded. The following are characteristics for different coating conditions.

5.3.3.6.1 Excellent Coating. Very good adhesion with less than 1% disbondment and occasional holidays. No electrolyte beneath the coating. Very minor to nonexistent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Uniform thickness of asphalt and coal tar coatings with no evidence of wrinkling.

5.3.3.6.2 Good Coating. Good adhesion with 1% to 10% disbondment and scattered holidays. Isolated locations with electrolyte beneath the disbonded coating. Minor intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Isolated evidence of poor adhesion, wrinkling, or other damage associated with soil stress on asphalt and coal tar coatings.

5.3.3.6.3 Fair Coating. Fair adhesion with 10% to 50% disbondment and scattered to numerous holidays. Intermittent locations with electrolyte beneath the disbonded coating. Intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Random areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Brittle asphalt and coal tar coatings.

5.3.3.6.4 Poor Coating. Poor adhesion with 50% to 80% disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.

5.3.3.6.5 Very Poor Coating. Very poor adhesion with greater than 80% disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.

5.3.3.7 Measurements of Coating Disbondment

5.3.3.7.1 Areas of coating disbondment are commonly identified and documented in SCC dig programs. The size and shape of the area of disbondment and the distance from the girth weld and the distance or clock position from the top of the pipe are measured and recorded.

5.3.3.8 Electrolyte Samples Beneath Disbonded Coatings

5.3.3.8.1 Electrolyte samples may be obtained (using a syringe) in cases in which sufficient liquid for sampling is present beneath disbonded coatings. Typically, the pH of the electrolyte is measured in the field and the sample is placed in an evacuated sample vial and returned to the laboratory for analysis. Measurement of the pH of a solution in the field is important because environmental contamination and ongoing chemical reactions within the sample can alter the pH prior to laboratory analysis. Litmus paper is commonly used for the field pH measurements. Litmus paper is commercially available in gradients of 0.5 units between 5.0 and 12.0. The laboratory analyses on each electrolyte sample should include pH and, if sample volumes permit, conductivity and general chemical analysis of the ionic composition. In some cases, samples also are analyzed for microbial activity. (See discussion of soil and groundwater samples in Section 7 of the CEPA Stress Corrosion Cracking Recommended Practices Manual.[10])

5.3.3.9 Photographic Documentation

5.3.3.9.1 It may be important to obtain photographic documentation of the dig site prior to coating removal. This should include the pipe prior to coating removal, the sidewalls of the ditch, and overall dig site. This information can be used to verify the topography, drainage, and soil type as well as the coating condition.

5.3.3.10 Data for Other Integrity Analyses Such as Corrosion, etc.

5.3.3.10.1 It is possible that integrity threats other than SCC have been identified for a pipeline segment that is included in an SCCDA program. Appropriate data shall be collected for these threats. The nature of the data collected depends on the integrity threat.

5.3.4 Coating Removal

5.3.4.1 The coating in the disbonded areas shall be removed so that the pipe surface can be examined. The method of coating removal is a function of the coating type.

5.3.5 Data Collection Following Coating Removal

5.3.5.1 Typical data measurements and related activities following coating removal are listed below. The CEPA Stress Corrosion Cracking Recommended Practices Manual[10] and Appendixes A and B of NACE SP0502[13] on ECDA contain additional information on the types of data that can be obtained and the measurement techniques.

5.3.5.2 Corrosion Products/Deposits

5.3.5.2.1 The presence and nature of any deposits or corrosion products on the pipe surface typically are described and photographed after coating removal. Samples also may be obtained for analysis. Field test kits are available for qualitative analysis on site. Different corrosion deposits have been correlated with the two types of SCC. Near-neutral-pH SCC has been associated with siderite ($FeCO_3$) while high-pH SCC has been associated with nahcolite ($NaHCO_3$) or magnetite (Fe_3O_4). If moisture is present on the pipe surface beneath disbonded coatings, the pH should be measured using litmus paper and recorded. The color, texture, composition, and distribution of the corrosion products and deposits should be documented.

5.3.5.3 Identification of Corrosion Defects

5.3.5.3.1 The pipeline operator shall document all corrosion defects. Additional cleaning and pipe surface preparation shall be made prior to depth and morphology measurements.

5.3.5.3.2 Mapping and measurement of corrosion defects. See Appendix C of NACE SP0502[13] for information on mapping and measurement of corrosion defects and the body of SP0502 for information on remaining-strength calculations.

5.3.5.4 Photographic Documentation of Corrosion Defects. It is important to obtain photographic documentation of the corrosion defects for future reference, with location references (distance downstream from reference girth weld and clock orientation).

5.3.5.5 Pipe Preparation for MPI

5.3.5.5.1 The objective of the pipe preparation process is to remove coating residue and corrosion deposits in order to enable inspection of the pipe surface for cracks.

5.3.5.5.2 In order to optimize the effectiveness of MPI techniques, the steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products, and coating remnants that could prevent contact of the magnetic particle medium with the steel surface.

5.3.5.5.3 The mobility of the magnetic particles must not be limited by an overly rough surface that interferes with the MPI method used.

5.3.5.5.4 The surface preparation must not mechanically damage the surface such that any cracks present are masked. Appendix B (nonmandatory) describes and summarizes the advantages and disadvantages of various surface preparation techniques.

5.3.5.5.5 Section 6.2.1 of the CEPA Stress Corrosion Cracking Recommended Practices Manual[10] provides additional guidance on surface preparation.

5.3.5.6 Following cleaning, the pipe surface shall be inspected for crack-like defects by MPI. Four MPI techniques have been used to detect surface-breaking defects on the external surface of pipelines: dry powder MPI (DPMPI), wet visual MPI (WVMPI), wet fluorescent MPI (WFMPI), and black on white MPI (BWMPI). Appendix C (nonmandatory) describes and summarizes the advantages and disadvantages of these MPI techniques.

5.3.5.7 Following the completion of the MPI, each detected crack cluster shall be documented and evaluated for safety.

5.3.5.7.1 Each detected cluster shall be given a unique identifier and the location of the center of the colony shall be identified relative to a reference point such as a weld and a clock position.

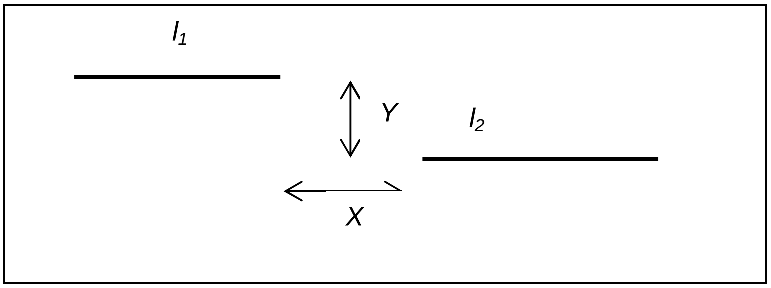
5.3.5.7.2 Typical information that is obtained for an individual crack cluster is described below.

5.3.5.7.3 Axial length, circumferential length, maximum length, and width of the colony. The axial length is the total length of the colony in the axial direction. The circumferential length is the total length of the colony in the circumferential direction. The length of the colony is the maximum length of the colony, which might be different from the axial or circumferential length, depending on the colony orientation. The width of the colony is the dimension of the colony perpendicular to the length direction.

5.3.5.7.4 Presence of interlinking. Cracks are defined to have interlinked if they physically have joined (coalesced) to form one longer crack.

5.3.5.7.5 Presence of interacting cracks. Crack interaction is dependent on the circumferential and axial separation between individual (or interlinked) cracks and is calculated as follows:

5.3.5.7.5.1 Two neighboring cracks, as illustrated below, are defined as interacting if their circumferential spacing Y is as indicated in Equation (1):



$$Y \leq 0.14 \frac{(l_1 + l_2)}{2} \qquad (1)$$

and if their axial spacing X is as indicated in Equation (2):

$$X < 0.25 \frac{(l_1 + l_2)}{2} \qquad (2)$$

Where l_1 and l_2 are the individual crack lengths.

5.3.5.7.6 Maximum crack length, including interlinking and interacting cracks. The maximum crack length is the total length of the longest interacting and interlinking cracks, as defined above.

5.3.5.7.7 Presence of significant cracking. As defined in Section 2, an SCC cluster is assessed to be significant by CEPA if the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. A significant crack potentially could fail in a hydrostatic test and therefore is considered to be an eventual integrity threat to the pipeline. The presence of extensive and significant SCC typically triggers an SCC mitigation program (see discussion under Post-Assessment Step in Section 6), but a crack that is labeled “significant” is not necessarily an immediate threat to the integrity of the pipeline.

5.3.5.7.8 Maximum crack depth and how it was determined. The maximum crack depth is important in evaluating whether the cracking is significant and in estimating the failure pressure. The maximum depth of stress corrosion cracks in a cluster typically is difficult to measure using indirect techniques such as ultrasonic test (UT) because of interaction of the signal with the cracks in the cluster. Grinding or buffing, in conjunction with MPI, is a method that is commonly used to determine the maximum depth of the longest interlinked crack at a dig site. It is then typically assumed that all other cracks in the dig are less deep. This method also can be used to evaluate the accuracy of other crack-depth measurement techniques. If grinding is to be performed on a pressurized line, the initial wall thickness shall be determined by UT, and a safe wall thickness must be maintained at all times during grinding. Specific guidelines can be found in the PRCI Pipeline Repair Manual.[14]

5.3.5.7.9 Average circumferential separation of adjacent cracks. The average circumferential separation of adjacent cracks is important to document because it has been found that sparsely spaced cracks are more likely to align to form significant cracks. Adjacent cracks in clusters of densely spaced cracks tend to relieve tensile stresses at the tips of nearby cracks and are less likely to be integrity concerns.

5.3.5.7.10 Results of in situ metallography, if available. In situ metallography is used to examine the microstructure of the steel and the path (intergranular versus transgranular) of the stress corrosion cracks. This information can be used to establish the type of SCC (high-pH SCC [intergranular] versus near-neutral-pH SCC [transgranular]). In situ metallography requires a portable microscope or replication, and it shall be performed by personnel qualified in metallographic preparation and the analysis of microstructures.

5.3.5.7.11 Ultrasonic measurement of wall thickness at cluster location. The wall thickness, in conjunction with the dimensions of the interlinked cracks and mechanical properties of the pipe joint, is used to estimate the failure pressure of the pipe segment containing the SCC. Ultrasonic measurements shall be made by qualified personnel in accordance with a specification and a written procedure. The written procedure shall be developed and approved by personnel with sufficient qualifications in the specific method of inspection to be used. For the purpose of wall-thickness measurement using ultrasonic techniques, an ASNT[(8)] certification shall not be required. Proper UT techniques are described in ASTM E 317.[15]

5.3.5.7.12 Photograph of crack cluster. It is useful to photograph crack clusters for archival purposes and for subsequent reevaluation of the cracking in cases in which questions arise concerning the field assessment of the cracking.

5.3.5.7.13 Additional guidance on information obtained for a crack cluster is given in Section 7.5.3 of the CEPA Stress Corrosion Cracking Recommended Practices Manual.[10]

5.4 Analysis of Type of Cracking

5.4.1 Indications of cracking detected by this inspection procedure can be the result of several causes, including near-neutral-pH SCC, high-pH SCC, mechanical damage, or even noninjurious mill imperfections.

5.4.2 The necessity for and type of mitigation activity typically are dependent on the type of the cracking present.

5.4.3 The presence of cracking in clusters typically distinguishes SCC from other forms of cracking.

5.4.4 Near-neutral-pH SCC frequently is associated with light surface corrosion of the pipe. High-pH SCC usually is not associated with obvious external corrosion.

5.4.5 In some cases, in situ metallography might be required to confirm the type of SCC.

5.4.5.1 High-pH SCC is intergranular and typically is branched with little evidence of corrosion of the pipe outside surface and crack walls.

5.4.5.2 Near-neutral-pH SCC is transgranular and typically is unbranched, usually with evidence of corrosion of the pipe outside surface and crack walls. Near-neutral-pH SCC tends to be wider than high-pH SCC.

5.5 Evaluation of the Severity of Cracking

5.5.1 When SCC is detected, Section A3.4 of Part A of ASME B31.8S[1] shall be followed.

5.5.2 The SCCDA process helps find representative SCC clusters on a pipeline segment, but it might not find all such defects on the segment.

5.5.3 If SCC clusters that exceed allowable limits are found, it shall be assumed that other similar defects might be present elsewhere in the segment.

Section 6: Post Assessment

6.1 Introduction

6.1.1 The objectives of the Post Assessment Step are to determine whether general SCC mitigation is required, prioritize remedial action for defects that are not removed immediately, define reassessment intervals, and evaluate the effectiveness of the SCCDA approach.

6.1.2 Primary guidance for SCC mitigation is provided in Part A3 of ASME B31.8S.[1]

6.1.3 Each pipeline company is responsible for selecting post-assessment options, including developing, implementing, and verifying a plan to define reassessment intervals, and evaluating the effectiveness of the SCCDA approach.

6.2 Mitigation

6.2.1 Discrete Mitigation

Discrete mitigation addresses isolated locations at which significant SCC has been detected during the course of the field investigation program. Typically, this form of mitigation is limited to areas where the affected pipe length is relatively short, less than 91 m (300 ft) in length. Section A3.4 of ASME B31.8S[1] and Paragraph 5.5 of this standard describe mitigation options. These include:

6.2.1.1 Repair or removal of the affected pipe length.

[(8)] American Society for Nondestructive Testing (ASNT), 1711 Arlingate Lane, Columbus, OH 43228-0518.

6.2.1.2 Hydrostatically testing the pipeline segment.

6.2.1.3 Performing an engineering critical assessment to evaluate the risk and identify further mitigation methods.

6.2.2 General Mitigation

General mitigation addresses pipeline segments when the risk of significant SCC could potentially be widespread within a particular segment or segments of a pipeline. Typically, this form of mitigation is used to address areas in which the affected pipe length is relatively long. General forms of mitigation include:

6.2.2.1 Hydrostatic testing of affected segment or segments.

6.2.2.2 ILI when appropriate tools are available.

6.2.2.3 Extensive pipe replacements.

6.2.2.4 Recoating.

6.3 Periodic Reassessment

6.3.1 Periodic reassessment is the process in which given segments of a pipeline are reinvestigated at an appropriate time interval.

6.3.2 It is up to the discretion of the operator to establish the number of additional investigations that are required on a given segment and the reassessment intervals based on information such as:

6.3.2.1 The extent and severity of the SCC detected during the original investigation.

6.3.2.2 The estimated rate of propagation of the crack clusters and remaining life of the pipe containing the clusters.

6.3.2.3 The total length of the pipe segment.

6.3.2.4 The total length of potentially susceptible pipe within the segment.

6.3.2.5 The potential consequences of a failure within a given segment.

6.3.3 The company shall consider whether the criteria used for dig site selection in the initial assessment are appropriate for the reassessment.

6.4 Effectiveness of SCCDA

6.4.1 It is up to the discretion of the operator to establish the method(s) used to evaluate the effectiveness of the SCCDA approach.

6.4.2 SCCDA is a continuous improvement process. Through successive SCCDA applications, a pipeline operator should be able to better identify segments and locations on the system where significant SCC is likely to occur.

6.4.3 Methods used to assess SCCDA effectiveness include, but are not limited to, the following:

6.4.3.1 Comparison of results for selected dig sites with results for control digs.

6.4.3.2 Comparison of results of SCCDA for selected segments with results of ILI using crack-detection tools.

6.4.3.3 Statistical analysis of data from SCCDA digs to identify statistically significant factors associated with the occurrence or severity of cracking.

6.4.3.4 Successive applications of SCCDA to a pipeline segment.

6.4.3.5 Assessment of SCC predictive models with respect to reliability of predicting locations and severity of SCC.

Section 7: SCCDA Records

7.1 Introduction

7.1.1 The objective of this section is to document clearly and concisely the data and information collected and decisions made during the SCCDA process.

7.2 Pre-Assessment Documentation

7.2.1 All Pre-Assessment Step actions shall be recorded. The documentation may include, but is not limited to, the following:

7.2.1.1 Documentation on the analysis used to select susceptible segments for SCCDA.

7.2.1.2 Data elements collected for the segments to be evaluated, in accordance with Table 1.

7.2.1.3 Methods and procedure used to integrate data, prioritize segments, and select dig sites.

7.3 Indirect Inspections

7.3.1 All Indirect Inspection Step actions shall be recorded. The documentation may include, but is not limited to, the following:

7.3.1.1 Documentation on the analysis used to identify data needs and select specific indirect inspection techniques.

7.3.1.2 Data elements collected for the segments to be evaluated.

7.3.1.3 Methods and procedure used to integrate data, prioritize segments, and select dig sites.

7.4 Direct Examination Documentation

7.4.1 All Direct Examination Step actions shall be recorded. The documentation may include, but is not limited to, the following:

7.4.1.1 Data collected for field site verification.

7.4.1.2 Data collected prior to coating removal.

7.4.1.3 Data collected after coating removal.

7.4.1.4 Results of analysis of cracking, if found.

7.4.1.5 Results of assessment of severity of cracking, if found.

7.5 Post Assessment

7.5.1 All Post-Assessment Step actions shall be recorded. The documentation may include, but is not limited to, the following:

7.5.1.1 Whether mitigation was required, the type of mitigation selected, and the justification for the selection.

7.5.1.2 Criteria used to select reassessment intervals and the intervals selected.

7.5.1.3 Scheduled activities, if any.

7.5.1.4 Criteria used to assess ECDA effectiveness and results from assessments.

References

1. ANSI/ASME B31.8S (latest revision), “Managing System Integrity of Gas Pipelines” (New York, NY: ASME).

2. NACE Publication 35103 (latest revision), “External Stress Corrosion Cracking of Underground Pipelines” (Houston, TX: NACE).

3. NACE SP0206 (latest revision), “Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)” (Houston, TX: NACE).

4. ANSI/ASME B31.4 (latest revision), “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids” (New York, NY: ASME).

5. ANSI/ASME B31.8 (latest revision), “Gas Transmission and Distribution Piping Systems” (New York, NY: ASME).

6. API Standard 1160 (latest revision), “Managing System Integrity for Hazardous Liquid Pipelines” (Washington, DC: API).

7. ANSI/ASME B31G (latest revision), “Manual for Determining the Remaining Strength of Corroded Pipelines A Supplement to B31, Code for Pressure Piping” (New York, NY: ASME).

8. ASTM E 709 (latest revision), “Standard Guide for Magnetic Particle Examination” (West Conshohocken, PA: ASTM).

9. P.H. Vieth, J.F. Kiefner, RSTRENG2 (DOS Version) User’s Manual and Software (Includes: L51688B Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe) (Arlington, VA: PRCI, 1993).

10. Canadian Energy Pipeline Association, Stress Corrosion Cracking Recommended Practices Manual (Calgary, AB: CEPA, 1997).

11. NACE SP0207 (latest revision), “Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines” (Houston, TX: NACE).

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13. NACE SP0502 (latest revision), “Pipeline External Corrosion Direct Assessment Methodology” (Houston, TX: NACE).

14. J.F. Kiefner, W.A. Bruce, D.R. Stephens, “Pipeline Repair Manual,” PRCI Project PR-218-9307 (Arlington, VA: PRCI).

15. ASTM E 317 (latest revision), “Standard Practice for Evaluating Performance Characteristics of Ultrasonic Pulse-Echo Examination Instruments and Systems Without the Use of Electronic Measurement Instruments” (West Conshohocken, PA: ASTM).

16. R.J. Eiber, B.N. Leis, “Protocol to Prioritize Sites for High pH Stress-Corrosion Cracking in Gas Pipelines,” PRCI Project PR-3-9403 (Arlington, VA: PRCI).

17. T.R. Baker, G.G. Rochfort, R.N. Parkins, “Investigations Related to Stress Corrosion Cracking on the Pipeline Authority’s Moomba to Sydney Pipeline,” in the 7th Symposium on Pipeline Research, PRCI Catalogue No. L51495 (Arlington, VA: PRCI, 1986), pp. 27-1 to 27-25.

Appendix A:
Relationship Between Soils and SCC
(Nonmandatory)

There are no published correlations between soil composition and high-pH SCC except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. There is some evidence that pipelines in soils that experience alternate periods of high and low moisture might be more prone to SCC,[16] and there is one report of a pipeline that traversed alternate areas of wet, low-resistivity clay, and dry high-resistivity sand and experienced SCC only in the low-resistivity areas.[17]

Some success has been experienced in correlating near-neutral-pH SCC with specific soil types, drainage, and topography. Tables A1 and A2 are descriptions of the SCC-susceptible terrain conditions identified by CEPA[10] for polyethylene-tape-coated and asphalt/coal-tar-coated pipelines, respectively.

Table A1
Description of “Stress Corrosion Cracking-Susceptible” Terrain Conditions for Polyethylene-Tape-Coated Pipelines (Based on Findings of CEPA Member Companies)

Soil Environmental Description	Topography	Drainage
Lacustrine (clayey to silty, fine-textured soils)	Inclined, level, undulating	Very poor
Lacustrine (clayey to silty, fine-textured soils)	Inclined, level, undulating, depressional	Poor
Organic soils (> 1 m [3 ft] in depth) overlaying glaciofluvial (sandy and/or gravel-textured soils)	Level, depressional	Very poor
Organic soils (> 1 m [3 ft] in depth) overlaying lacustrine (clayey to silty, fine-textured soils)	Level, depressional	Very poor
Moraine tills (variable soil texture—sand, gravel, silt, and clay with a stone content > 1%)	Inclined to level level undulating ridged, depressional	Very poor Poor Imperfect to poor
Moraine tills (variable soil texture—sand, gravel, silt, and clay with a stone content > 1%)	Inclined	Imperfect to poor

Table A2
Description of "Stress Corrosion Cracking-Susceptible" Terrain Conditions for Some Asphalt/Coal-Tar-Enamel-Coated Pipelines (Based on Findings of CEPA Member Companies)

Soil Environmental Description	Topography	Drainage
Bedrock and shale limestone (< 1 m [3 ft] of soil cover over bedrock or shale limestone)	Inclined level Undulating ridged	Good
Glaciofluvial (Sandy or gravel-textured soils)	Inclined level Undulating ridged	Good
Moraine till (Sandy/clay soil texture with a stone content > 1%)	Inclined level Undulating ridged	Good
Sites that do not meet the –850 mV "off" criteria in a close pipe to soil survey (Exclusive of the three sets of terrain conditions discussed above)	Any	Any

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Appendix B:
Surface Preparation Techniques
(Nonmandatory)

The employment of MPI requires adequate surface preparation in accordance with ASTM E 709.[8] When mechanical cleaning methods are used, care should be taken to perform the least aggressive preparation needed consistent with inspection of the surface. For disbonded areas of coating that can be removed without the use of a blasting medium, solvent cleaning may be adequate. Adhered coating need not be removed for SCC inspection because SCC does not occur at locations where the coating is adhered to the pipe surface. Pipe cleaning that requires the use of a wire brush or a blasting medium such as water, silica, slag, or other abrasives should be performed with the goal of removing disbonded coating in a manner that minimizes alteration of the pipe surface.

CEPA[10] evaluated four techniques for surface preparation prior to wet MPI of SCC crack clusters: high-pressure water blast, abrasive blasting with walnut shells, abrasive blasting with silica sands and slags, and power wire brushing. Table B1 summarizes the advantages and disadvantages of these techniques and Table B2 compares the techniques to their detection limits and costs.

Table B1
Summary of Surface Preparation Techniques Prior to MPI

Surface Preparation Technique	Description	Advantages	Disadvantages
Water blasting	Uses potable water at very high pressures (i.e., >172 MPa [25,000 psi]).	Does not create a surface roughness and therefore eliminates any concern for crack masking. Can be used with additives to remove greasy residues.	Does not always remove tenacious corrosion products. Only potable water can be used in the high-pressure equipment, and potable water resources are not reliable. Excavation site becomes muddy. Freezing concerns in winter. Safety concerns with high-pressure discharge. Limited availability of equipment.
Abrasive blasting with walnut shells	Walnut shells are used as an abrasive medium employing the same equipment common to sand and slag abrasive blasting.	As an abrasive, walnut shells are relatively soft; therefore masking is very unlikely. Skilled operators are readily available.	Does not always remove tenacious corrosion products. Leaves an oily residue that may affect subsequent pipe recoating effectiveness (residue can be removed with cleaning agents). Possible allergic reactions.
Abrasive blasting with silica sands or slags	Relatively hard abrasives such as silica sand and coal slag are filled into pressurized pots, which discharge the abrasive through a hose and nozzle at a pressure of approximately 0.69 MPa (100 psi) measured at the nozzle.	Provides the highest level of steel cleanliness of all techniques. Skilled operators and materials are readily available. Subsequent surface preparation for recoating requirements is minimized.	User must be conscientious in selecting the appropriate abrasive grade and blast settings in order to ensure small cracks are not masked. In some areas, the use of silica sand is regulated because of occupational health concerns and workplace exposure.
Power wire brush 180 grit flapper wheel	Electric or pneumatic grinding tools are fitted with specialized rotating disks or wheels, which mechanically clean by abrasion and remove base material.	Simple-to-use equipment with little maintenance and refuse.	Consistent cleaning quality across inspection surface can be difficult to achieve. User must be conscientious in selecting the appropriate abrasive grade in order to control masking of cracks.

Table B2
Comparison of Surface Preparation Techniques vs. Detection Limits and Cost

Surface Preparation Technique	Detectability	Crack Sizes Detectable Using WFMPI, mm (in)	Crack Sizes Detectable Using BWMPI, mm (in)	Cost Ranking (1 = most expensive)	Cleaning Rate
Water blasting	Excellent, as long as all corrosion products, etc., can be removed.	1 (0.04)	1 to 2 (0.04 to 0.08)	4	Satisfactory cleaning rate but cannot remove some corrosion deposits.
Walnut shells	Excellent, as long as all corrosion products, etc., can be removed.	1 (0.04)	1 to 2 (0.04 to 0.08)	3	Good cleaning rate but cannot remove some corrosion deposits.
Sand and (slag)	Very good.	1 to 2 (0.04 to 0.08)	1 to 2 (0.04 to 0.08)	2	Overall, provides best cleaning rate of all techniques. Somewhat dependent on abrasive sharpness.
Wire wheel, etc.	Satisfactory, very minor (1 to 2 mm [0.04 to 0.08 in]) cracks can be masked.	No data	2 to 3 (0.08 to 0.12)	1	Slow for large areas, but removes tenacious substances.

Appendix C: Manual Inspection for SCC (Nonmandatory)

Dry and wet MPI methods such as DPMPI, WVMPI, WFMPI, and BWMPI can be used to detect external surface-breaking pipe defects after the pipe surface is cleaned. All four techniques are proven methods to detect external SCC, and it is the pipeline operator's responsibility to demonstrate that the technique(s) selected and the protocols used are effective in detecting SCC. ASTM E 709[8] describes MPI techniques to detect cracks, including SCC in ferromagnetic materials, and is commonly cited to develop, monitor, and evaluate inspection procedures.

The method of magnetization of the pipe surface has been investigated, but the most practical and easiest to use is a hand yoke. Alternating current (AC) and direct current (DC) hand yokes are available to complete a MPI inspection. The most commonly used yoke for SCC investigations is the AC type because it specifically detects surface-breaking defects.

The most critical factor during the SCC inspection process is the experience of the technician to evaluate and classify the indications detected on the pipe surface. The technician needs to demonstrate a knowledge and ability to discriminate SCC from those indications resembling SCC such as toe-weld indications, delaminations, undercut, laps, slivers, or scabs.

Provided in Table C1 is a comparison of the four types of MPI methods most commonly used to undertake SCC inspections.

Table C1: Advantages and Disadvantages of Various MPI Methods

MPI Method	Ultimate Sensitivity	Advantages	Disadvantages
DPMPI	2 to 5 mm (0.08 to 0.20 in) long defects.	Maximum portability. Crack replicas can be obtained.	Regardless of pipe cleaning technique, this technique when used with an AC yolk yields the lowest sensitivity of all the MPI techniques. Must have a very clean surface; dampness affects particle distribution and mobility. Subject to climate limitations (i.e., wind can blow the powder around and create a health and safety hazard for the technicians.
WFMPI	1 mm (0.04 in) long defects.	Highest degree of sensitivity. Dry concentration plus a water conditioner mix readily with water.	Longer set-up time. Requires more inspection equipment compared to other methods. Difficult to document SCC because of darkness required during inspection. Seasonal conditions can cause overheating and malfunction of inspection equipment. Photography can be done but more difficult compared with BWMPI or WVMPI methods because of darkness required during inspection. Safety hazards in wet, sloppy excavation sites. Subject to climate limitations (i.e., wind can make it difficult to keep the light-retarding tarp in place, and high ambient temperatures can make it very hot and uncomfortable for the technicians beneath the light-retarding tarp).
WVMPI	1 to 2 mm (0.04 to 0.08 in) long defects.	Requires less set-up time than WFMPI or BWMPI. Requires less MPI equipment than WFMPI. Easier to photograph SCC indications than with WFMPI or DPMPI.	Flux properties are affected by freezing and low temperatures. Photography not as easy as with BWMPI.
BWMPI	1 to 2 mm (0.04 to 0.08 in) long defects.	Requires less MPI equipment than WFMPI. Makes it easier to photograph SCC indications—weather permitting.	Contrast paint and flux are pre-mixed; therefore, a larger supply is required compared with the concentrated form of dry particles mixed with solvent utilized for the WVMPI and WFMPI methods. Paint and flux properties affected by freezing and low temperatures. Aerosols can pose a health and safety hazard. Applying the white contrast can be time-consuming.