ANSI/NACE SP0502-2010
(formerly RP0502)
Item No. 21149

Standard Practice

Pipeline External Corrosion Direct Assessment Methodology

NOTICE:

This NACE Standard is being made available to you at no charge because it is incorporated by reference in the U.S. Code of Federal Regulations (CFR) Title 49. "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards," Parts 192 and 195.

For a list of other NACE standards pertaining to direct assessment (DA) and pipeline integrity issues, see the NACE Pipeline Web Page.

NACE's Mission

Protect people, assets, and the environment from the effects from corrosion.

Revised 2010-06-24
Reaffirmed 2008-03-20
Approved 2002-10-11
NACE International
1440 South Creek Dr.
Houston, Texas 77084-4906
+1 281-228-6200
ISBN 1-57590-156-0

An American National Standard
Approved December 3, 2010

Foreword

External corrosion direct assessment (ECDA) is a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity. By identifying and addressing corrosion activity, repairing corrosion defects, and remediating the cause, ECDA proactively seeks to prevent external corrosion defects from growing to a size that is large enough to affect structural integrity.

ECDA as described in this standard practice is specifically intended to address buried onshore pipelines constructed from ferrous materials. Other methods of addressing external corrosion on onshore ferrous pipelines, such as pressure testing and in-line inspection (ILI), are not covered in this standard but are covered in other industry standards. 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 is intended for use by pipeline operators and others who must manage pipeline integrity.

ECDA is a continuous improvement process. Through successive ECDA applications, a pipeline operator should be able to identify and address locations at which corrosion activity has occurred, is occurring, or may occur. One of the advantages of ECDA is that it can locate areas where defects could form in the future rather than only areas where defects have already formed.

Pipeline operators have historically managed external corrosion using some of the ECDA tools and techniques. Often, data from aboveground inspection tools have been used to locate areas that may be experiencing external corrosion. The ECDA process takes this practice several steps forward and integrates information on a pipeline's physical characteristics and operating history (preassessment) with data from multiple field examinations (indirect inspection) and pipe surface evaluations (direct examination) to provide a more comprehensive integrity evaluation with respect to external corrosion (postassessment).

This standard was originally prepared in 2002 by Task Group (TG) 041, "Pipeline Direct Assessment Methodology." It was reaffirmed in 2008 by Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings," and revised in 2010 by TG 041. This standard is issued by NACE International 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.

NACE International
Standard Practice

Pipeline External Corrosion Direct Assessment Methodology

Contents

Section 1: General

1.1 Introduction

1.1.1 This standard covers the NACE external corrosion direct assessment (ECDA) process for buried onshore ferrous pipeline systems. This standard is intended to serve as a guide for applying the NACE ECDA process on typical pipeline systems.

1.1.2 This standard was written to provide flexibility for an operator to tailor the process to specific pipeline situations.

1.1.3 ECDA is a continuous improvement process. Through successive applications, ECDA should identify and address locations at which corrosion activity has occurred, is occurring, or may occur.

1.1.3.1 ECDA provides the advantage and benefit of locating areas where defects may form in the future rather than only areas where defects have already formed.

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

1.1.4 ECDA was developed as a process for improving pipeline safety. Its primary purpose is preventing future external corrosion damage.

1.1.4.1 This standard assumes external corrosion is a threat to be evaluated. It can be used to establish a baseline from which future corrosion can be assessed for pipelines when external corrosion is not currently a significant threat.

1.1.5 ECDA as described in this standard is specifically intended to address buried onshore pipelines constructed from ferrous materials.

1.1.6 ECDA applications can include but are not limited to assessments of external corrosion on pipeline segments that:

1.1.6.1 Cannot be inspected using other inspection methods (such as ILI or pressure testing).

1.1.6.2 Have been inspected using other inspection methods as a method of managing future corrosion.

1.1.6.3 Have been inspected with another inspection method as a method of establishing a reassessment interval.

1.1.6.4 Have not been inspected using other inspection methods when managing future corrosion is of primary interest.

1.1.7 ECDA may detect other pipeline integrity threats, such as mechanical damage, stress corrosion cracking (SCC), and microbiologically influenced corrosion (MIC). When such threats are detected, additional assessments or inspections must be performed. The pipeline operator should use appropriate methods such as ASME(1) B31.4,[1] ASME B31.8,[2] ASME B31.8S,[3] and API(2) Std 1160[4] to address risks other than external corrosion.

---

(1) ASME International (ASME), Three Park Ave., New York, NY 10016-5990.
(2) American Petroleum Institute (API), 1220 L St. NW, Washington, DC 20005-4070.

1.1.8 ECDA has limitations and all pipelines cannot be successfully assessed with ECDA. Precautions should be taken when applying these techniques just as with other assessment methods.

1.1.8.1 This standard may be applied to poorly coated or bare pipelines in accordance with the methods and procedures included herein and given in NACE SP0207[5] and NACE Standard TM0109.[6] Poorly coated pipelines are usually treated as essentially bare if the cathodic current requirements to achieve protection are substantially the same as those for bare pipe.

1.1.9 For accurate and correct application of this standard, the standard shall be used in its entirety. Using or referring to only specific paragraphs or sections can lead to misinterpretation and misapplication of the recommendations and practices contained herein.

1.1.10 This standard does not designate practices for every specific situation because of the complexity of conditions to which buried pipeline systems are exposed.

1.1.11 The provisions of this standard should be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on buried ferrous piping systems. Such persons may be registered professional engineers or persons recognized as corrosion specialists or cathodic protection (CP) specialists by organizations such as NACE or engineers or technicians with suitable levels of experience, if their professional activities include external corrosion control of buried ferrous piping systems.

1.2 Four-Step Process

1.2.1 ECDA requires the integration of data from multiple field examinations and from pipe surface evaluations with the pipeline's physical characteristics and operating history.

1.2.2 ECDA includes the following four steps, as shown in Figures 1(a) and 1(b):

1.2.2.1 Preassessment. The *Preassessment Step* collects historic and current data to determine whether ECDA is feasible, defines ECDA regions, and selects indirect inspection tools. The types of data to be collected are typically available in construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, and inspection reports from prior integrity evaluations or maintenance actions.

1.2.2.2 Indirect Inspection. The *Indirect Inspection Step* covers aboveground inspections to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity may have occurred or may be occurring. Two or more indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability under the wide variety of conditions that may be encountered along a pipeline right-of-way.

1.2.2.3 Direct Examination. The *Direct Examination Step* includes analyses of indirect inspection data to select sites for excavations and pipe surface evaluations. The data from the direct examinations are combined with prior data to identify and assess the effect of external corrosion on the pipeline. In addition, evaluation of pipeline coating performance, corrosion defect repairs, and mitigation of corrosion protection faults are included in this step.

1.2.2.4 Postassessment. The *Postassessment Step* covers analyses of data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals.

1.2.3 When ECDA is applied for the first time on a pipeline that does not have a good history of corrosion protection, including regular indirect inspections, more stringent requirements apply. These requirements include but are not limited to additional data collection, direct examinations, and postassessment activities.

1.2.3.1 For initial ECDA applications, more stringent requirements are used to provide an enhanced understanding of pipeline integrity with respect to external corrosion.

1.3 Supplemental Information

1.3.1 Data collection methods before coating removal used during the *Direct Examination Step* are presented in Appendix A (nonmandatory).

1.3.2 Corrosion damage and corrosion depth measurements used during the *Direct Examination Step* are presented in Appendix B (nonmandatory).

1.3.3 Corrosion rate estimation methods used during the *Postassessment Step* are presented in Appendix C (nonmandatory).

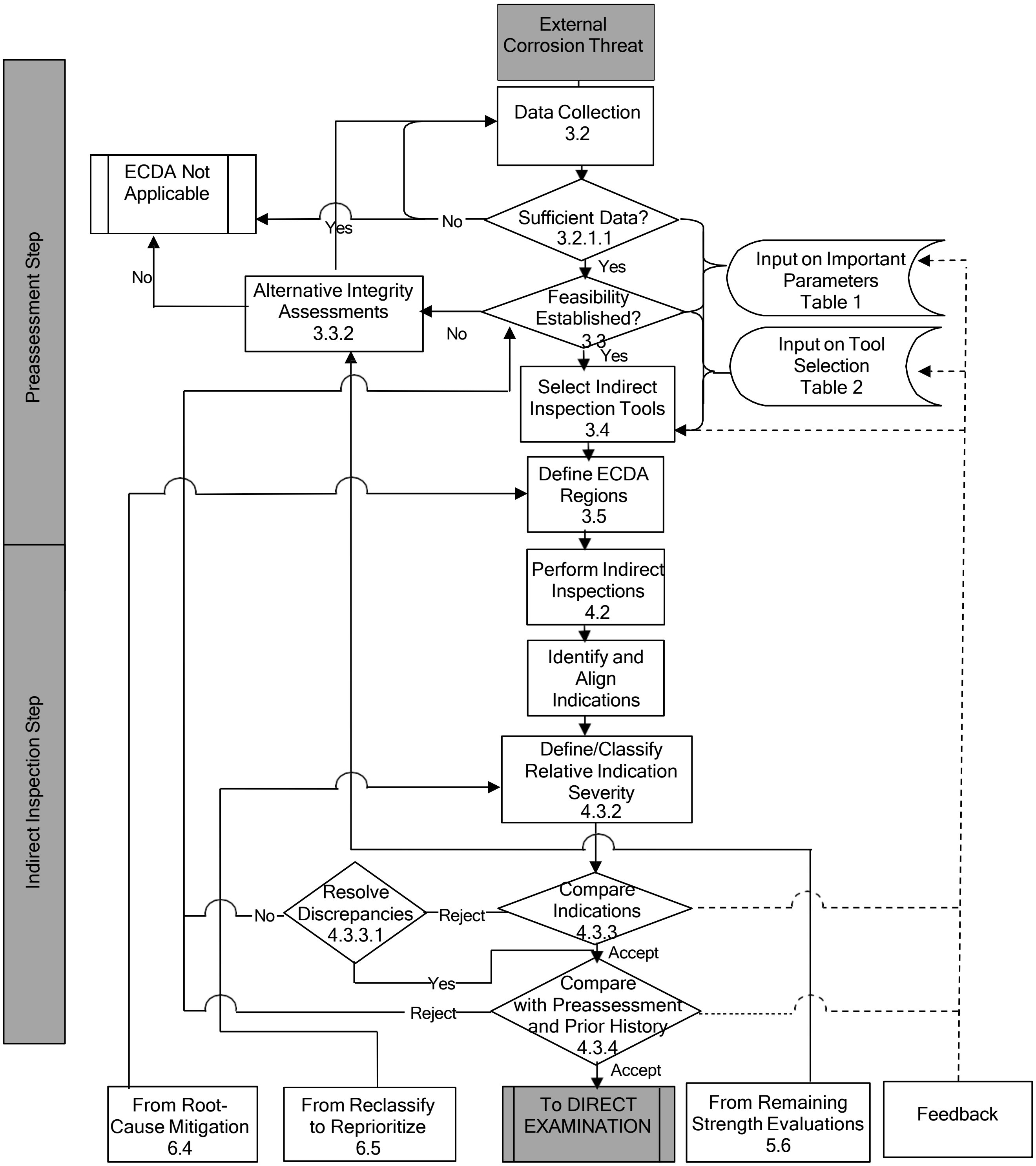

Figure 1(a): External Corrosion Direct Assessment Flow Chart—Part 1
(Numbers refer to paragraph numbers in this standard.)

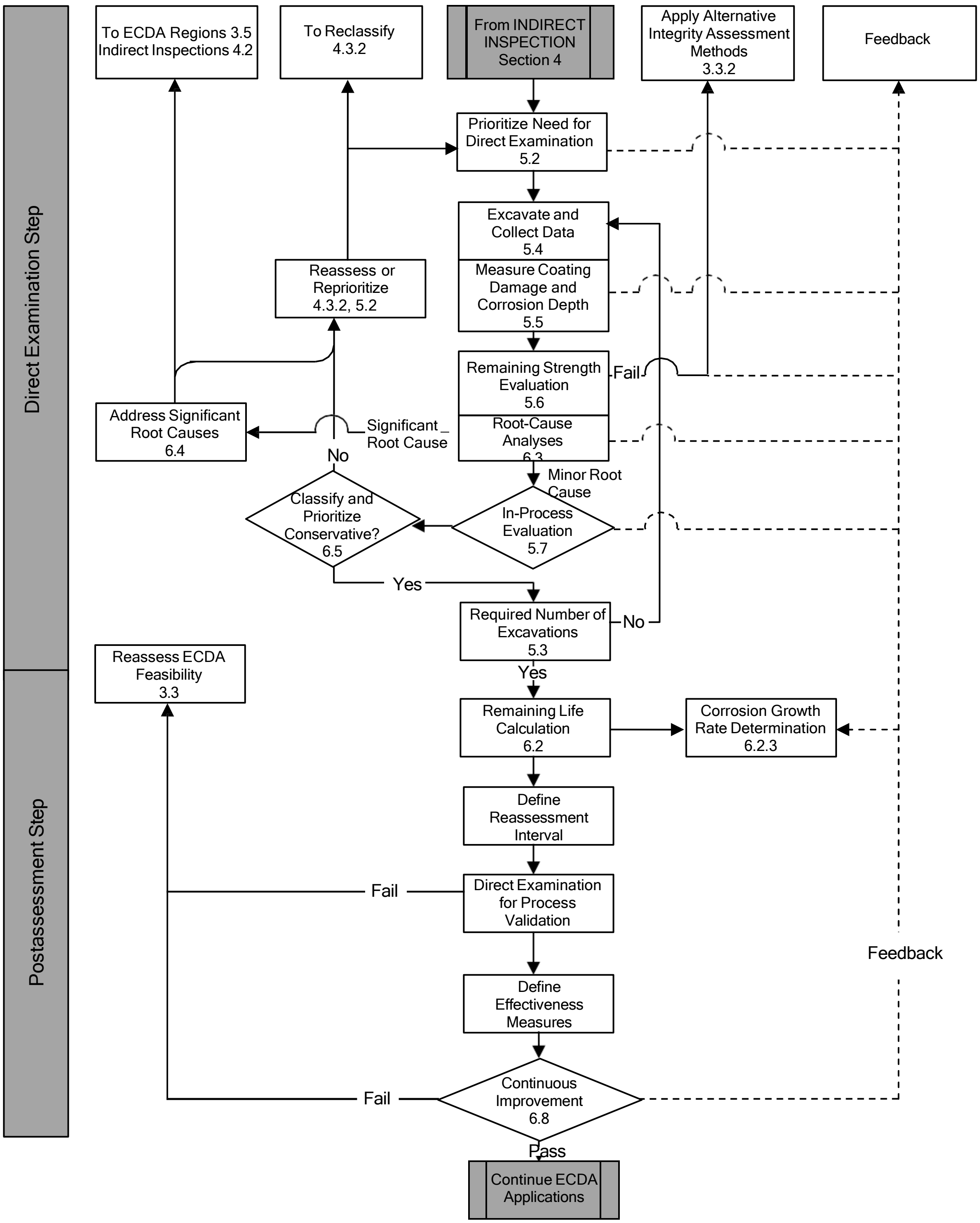

Figure 1(b): External Corrosion Direct Assessment Flow Chart—Part 2
(Numbers refer to paragraphs in this standard.)

Section 2: Definitions

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

Alternating Current Voltage Gradient (ACVG): A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

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

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

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 rate of a metal surface by making that surface the cathode of an electrochemical cell.

Classification: The process of estimating the likelihood of corrosion activity at an indirect inspection indication under typical year-round conditions.

Close-Interval Survey (CIS): A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.

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

Corrosion Activity: A state in which corrosion is active and ongoing at a rate that is sufficient to reduce the pressure-carrying capacity of a pipe during the pipeline design life.

Current Attenuation Survey: A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, anomaly location, and anomaly type.

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

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 ECDA.

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*.

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

ECDA Region: A section or sections of a pipeline that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and in which the same indirect inspection tools are used.

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 piping system, including the moisture and other chemicals contained therein.

External Corrosion Direct Assessment (ECDA): A four-step process that combines preassessment, indirect inspection, direct examination, and postassessment to evaluate the effect of external corrosion on the integrity of a pipeline.

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

Ferrous Material: A metal that consists mainly of iron. In this standard, ferrous materials include steel, cast iron, and wrought iron.

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

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

Immediate Indication: An indication that requires remediation or repair in a relatively short time span.

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 in-line inspection tool. The tools used to conduct ILI are known as *pigs* or *smart pigs*.

IR Drop: The voltage across a resistance when current is applied in accordance with Ohm's law.

Long-Line Current: Current flowing through the earth between an anodic and a cathodic area that returns along an underground metallic structure.

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

Mechanical Damage: Any of a number of types of anomalies in pipe, including dents, gouges, and metal loss, caused by the application of an external force.

Microbiologically Influenced Corrosion (MIC): Corrosion affected by the presence or activity, or both, of microorganisms.

Monitored Indication: An indication that is less significant than a scheduled indication and that does not need to be addressed or require remediation or repair before the next scheduled reassessment of a pipeline segment.

NACE ECDA: The external corrosion direct assessment process as defined in this standard.

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

Polarization: The change from the corrosion potential as a result of current flow across the electrode/electrolyte interface.

Prioritization: The process of estimating the need to perform a direct examination at each indirect inspection indication based on current corrosion activity plus the extent and severity of prior corrosion. The three levels of priority are immediate, scheduled, and monitored, in this order.

Region: See *ECDA Region*.

Remediation: As used in this standard, remediation refers to corrective actions taken to mitigate deficiencies in the corrosion protection system.

Root-Cause Analysis (from ASME B31.8S): Family of processes implemented to determine the primary cause of an event. These processes all seek to examine a cause-and-effect relationship through the organization and analysis of data.

RSTRENG[7]: A computer program designed to calculate the pressure-carrying capacity of corroded pipe.

Scheduled Indication: An indication that is less significant than an immediate indication, but which is to be addressed before the next scheduled reassessment of a pipeline segment.

Segment: A portion of a pipeline that is (to be) assessed using ECDA. A segment consists of one or more ECDA regions.

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

Sound Engineering Practice: Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.

Stray Current: Current flowing through paths other than the intended circuit.

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.

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

Section 3: Preassessment

3.1 Introduction

3.1.1 The objectives of the *Preassessment Step* are to determine whether ECDA is feasible for the pipeline to be evaluated, select indirect inspection tools, and identify ECDA regions.

3.1.2 The *Preassessment Step* requires a sufficient amount of data collection, integration, and analyses. The *Preassessment Step* must be performed in a comprehensive and thorough fashion.

3.1.3 The *Preassessment Step* includes the following activities, as shown in Figure 2:

3.1.3.1 Data collection;

3.1.3.2 Assessment of ECDA feasibility;

3.1.3.3 Selection of indirect inspection tools; and

3.1.3.4 Identification of ECDA regions.

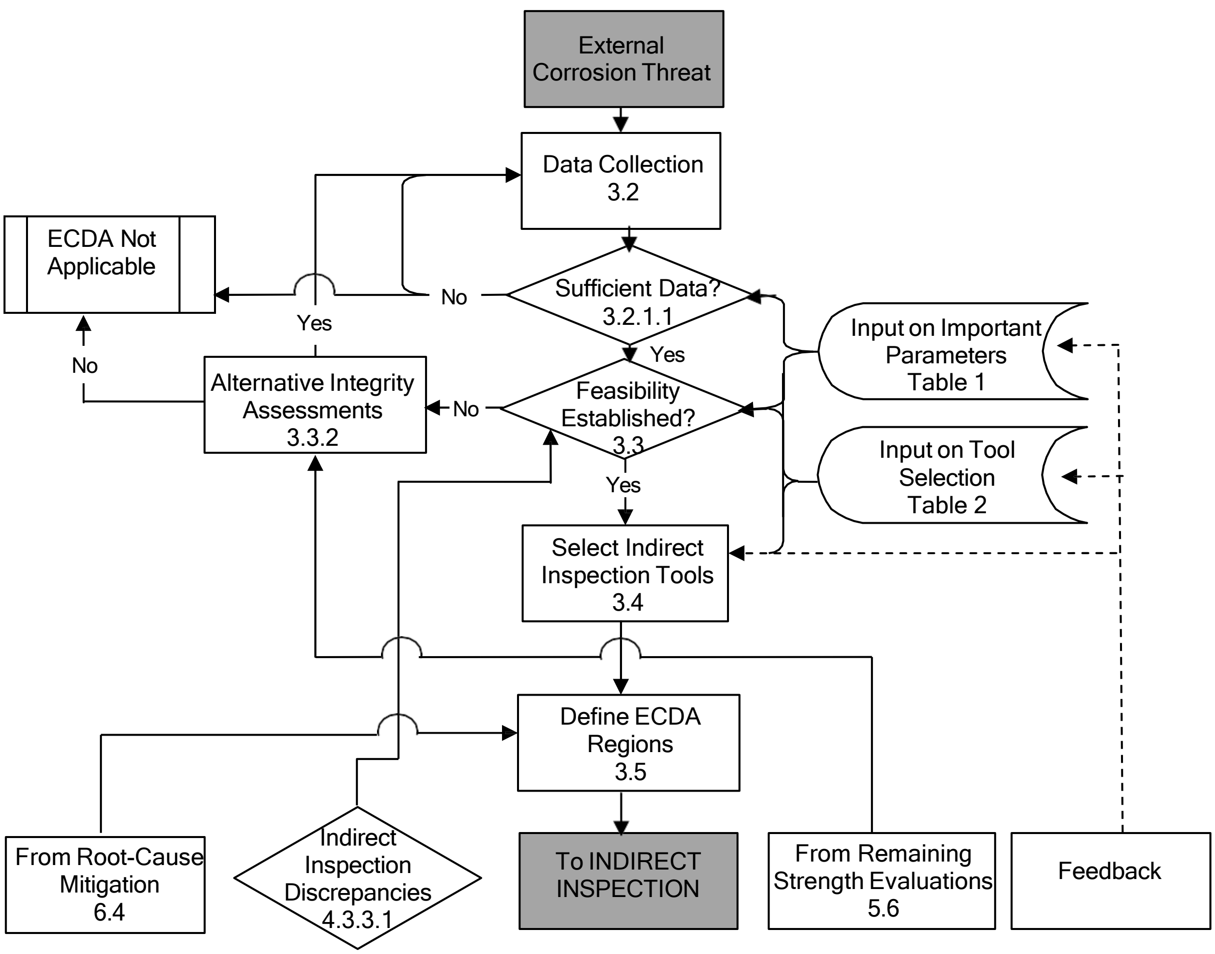

Figure 2: Preassessment Step
(Numbers refer to paragraphs in this standard.)

3.2 Data Collection

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 condition of the pipeline segment. In addition, the pipeline operator shall identify data elements that are critical to the success of the ECDA process.

3.2.1.2 All parameters that affect indirect inspection tool selection (see Paragraph 3.4) and ECDA region definition (see Paragraph 3.5) shall be considered for initial ECDA 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 for ECDA. 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.

3.2.2.1 Pipe related;

3.2.2.2 Construction related;

3.2.2.3 Soils/environmental;

3.2.2.4 Corrosion control; and

3.2.2.5 Operational data.

Table 1
ECDA Data Elements(A)

Data Elements	**Indirect Inspection Tool Selection**	**ECDA Region Definition**	**Use and Interpretation of Results**
PIPE RELATED			
Material (steel, cast iron, etc.) and grade	ECDA not appropriate for nonferrous materials.	Special considerations should be given to locations where dissimilar metals are joined.	Can create local corrosion cells when exposed to the environment.
Diameter	May reduce detection capability of indirect inspection tools.		Influences CP current flow and interpretation of results.
Wall thickness			Affects critical defect size and remaining life predictions.
Year manufactured			Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.

Data Elements	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
Seam type		Locations with pre-1970 low-frequency electric resistance welded (ERW) or flash-welded pipe with increased selective seam corrosion susceptibility may require separate ECDA regions.	Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW or flash-welded pipe seams may be subject to higher corrosion rates than the base metal.
Bare pipe	Limits ECDA application. Fewer available tools–See NACE SP0207 and NACE Standard TM0109.	Segments with bare pipe in coated pipelines should be in separate ECDA regions.	Specific ECDA methods provided in NACE SP0207 and NACE Standard TM0109.
CONSTRUCTION RELATED			
Year installed			Affects time over which coating degradation may have occurred, defect population estimates, and corrosion rate estimates.
Route changes/ modifications		Changes may require separate ECDA regions.	
Route maps/aerial photos		Provides general applicability information and ECDA region selection guidance.	Typically contain pipeline data that facilitate ECDA.
Construction practices		Construction practice differences may require separate ECDA regions.	May indicate locations at which construction problems may have occurred (e.g., backfill practices influence probability of coating damage during construction).
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, insulating joints, etc.		Significant drains or changes in CP current should be considered separately; special considerations should be given to locations at which dissimilar metals are connected.	May affect local current flow and interpretation of results; dissimilar metals may create local corrosion cells at points of contact; coating degradation rates may be different from adjacent regions.
Locations of and construction methods used at casings	May preclude use of some indirect inspection tools.	Requires separate ECDA regions.	May require operator to extrapolate nearby results to inaccessible regions. Additional tools and other assessment activities may be required.
Locations of bends, including miter bends and wrinkle bends		Presence of miter bends and wrinkle bends may influence ECDA region selection.	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results.

Data Elements	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
Depth of cover	Restricts the use of some indirect inspection techniques.	May require different ECDA regions for different ranges of depths of cover.	May affect current flow and interpretation of results.
Underwater sections and river crossings	Restricts the use of many indirect inspection techniques.	Requires separate ECDA regions.	Changes current flow and interpretation of results.
Locations of river weights and anchors	Reduces available indirect inspection tools.	May require separate ECDA regions.	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized, which affects local current flow and interpretation of results.
Proximity to other pipelines, structures, high-voltage electric transmission lines, and rail crossings	May preclude use of some indirect inspection methods.	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions.	Influences local current flow and interpretation of results.
SOILS/ENVIRONMENTAL			
Soil characteristics/types (Refer to Appendixes A and C.)	Some soil characteristics reduce the accuracy of various indirect inspection techniques.	Influences where corrosion is most likely; significant differences generally require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Drainage		Influences where corrosion is most likely; significant differences may require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Topography	Conditions such as rocky areas can make indirect inspections difficult or impossible.		
Land use (current/past)	Paved roads, etc., influence indirect inspection tool selection.	Can influence ECDA application and ECDA region selection.	
Frozen ground	May affect applicability and effectiveness of some ECDA methods.	Frozen areas should be considered separate ECDA regions.	Influences current flow and interpretation of results.
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	May affect ECDA tool selection.		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow and interpretation of results.

Data Elements	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
Stray current sources/locations			Influences current flow and interpretation of results.
Test point locations (or pipe access points)		May provide input when defining ECDA regions.	
CP evaluation criteria			Used in postassessment analysis.
CP maintenance history		Coating condition indicator.	Can be useful in interpreting results.
Years without CP applied		May make ECDA more difficult to apply.	Negatively affects ability to estimate corrosion rates and make remaining life predictions.
Coating type (pipe)	ECDA may not be appropriate for disbonded coatings with high dielectric constants, which can cause shielding.		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.
Coating type (joints)	ECDA may not be appropriate for coatings that cause shielding.		Shielding caused by certain joint coatings may lead to requirements for other assessment activities.
Coating condition	ECDA may be difficult to apply with severely degraded coatings.		
Current demand			Increasing current demand may indicate areas where coating degradation is leading to more exposed pipe surface area.
CP survey data/history			Can be useful in interpreting results.
OPERATIONAL DATA			
Pipe operating temperature		Significant differences generally require separate ECDA regions.	Can locally influence coating degradation rates.
Operating stress levels and fluctuations			Affects critical defect size and remaining life predictions.
Monitoring programs (coupons, patrol, leak surveys, etc.)		May provide input when defining ECDA regions.	May affect repair, remediation, and replacement schedules.
Pipe inspection reports (excavation)		May provide input when defining ECDA regions.	
Repair history/records (steel/composite repair sleeves, repair locations, etc.)	May affect ECDA tool selection.	Prior repair methods, such as anode additions, can create a local difference that may influence ECDA region selection.	Provide useful data for postassessment analyses such as interpreting data near repairs.

Data Elements	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
Leak/rupture history (external corrosion)		Can indicate condition of existing pipe.	
Evidence of external MIC			MIC may accelerate external corrosion rates.
Type/frequency (third-party damage)			High third-party damage areas may have increased indirect inspection coating fault detects.
Data from previous over-the-ground or from-the-surface surveys			Essential for preassessment and ECDA region selection.
Hydrostatic testing dates/pressures			Influences inspection intervals.
Other prior integrity-related activities–CIS, ILI runs, etc.	May affect ECDA tool selection–isolated vs. larger corroded areas.		Useful postassessment data.

(A) Those items that are shaded are most important for tool selection purposes.

3.2.3 The data collected in the *Preassessment 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 *Preassessment Step* in conjunction with a general risk assessment effort.

3.2.4 In the event the pipeline operator determines that sufficient data for some ECDA regions comprising a segment are not available or cannot be collected to support the *Preassessment Step*, ECDA shall not be used for those ECDA regions.

3.3 ECDA Feasibility Assessment

3.3.1 The pipeline operator shall integrate and analyze the collected data to determine whether conditions for which indirect inspection tools cannot be used or that would preclude ECDA application exist. The following conditions may make it difficult to apply ECDA:

3.3.1.1 Locations at which coatings cause electrical shielding;

3.3.1.2 Backfill with significant rock content or rock ledges;

3.3.1.3 Certain ground surfaces, such as pavements, frozen ground, and reinforced concrete;

3.3.1.4 Situations that lead to an inability to acquire aboveground measurements in a reasonable time frame;

3.3.1.5 Locations with adjacent buried metallic structures; and

3.3.1.6 Inaccessible areas.

3.3.2 If there are locations along a pipeline segment at which indirect inspections are not practicable (e.g., at certain cased road crossings), the ECDA process may be applied if the pipeline operator uses other methods of assessing the integrity of the location.

3.3.2.1 The other methods of assessing integrity must be tailored to the specific conditions at the location and shall be selected to provide an appropriate level of confidence in integrity.

3.3.3 If the conditions along a pipeline segment are such that indirect inspection or alternative methods of assessing integrity cannot be applied, this standard ECDA process is no longer applicable.

3.4 Selection of Indirect Inspection Tools

3.4.1 The pipeline operator shall select a minimum of two indirect inspection tools for all locations and regions where ECDA is to be applied along the pipeline segment (ECDA regions are defined in Paragraph 3.5).

3.4.1.1 The pipeline operator shall select indirect inspection tools based on their ability to detect corrosion activity and coating holidays reliably under the specific pipeline conditions to be encountered.

3.4.1.2 The pipeline operator should endeavor to select indirect inspection tools that are complementary. That is, the operator should select tools such that the strengths of one tool compensate for the limitations of another.

3.4.1.3 The pipeline operator may substitute a 100% direct examination in accordance with Appendixes A and B in lieu of indirect inspections and selected direct examinations at bellhole locations. In such a case, the preassessment and postassessment steps must also be followed.

3.4.2 The “indirect inspection tool selection” column in Table 1 includes items that should be considered when indirect inspection tools are selected. Those items that are shaded are most important for tool selection purposes.

3.4.3 Table 2 provides additional guidance on selecting indirect inspection tools and specifically addresses conditions under which some indirect inspection tools may not be practical or reliable. NACE SP0207 and NACE Standard TM0109 contain additional information on appropriate safety precautions that should be observed when electrical measurements are made.

Table 2
ECDA Tool Selection Matrix [(A)]

CONDITIONS	Close-Interval Survey (CIS)	Voltage Gradient Surveys (ACVG and DCVG)	Pearson[8]	Current Attenuation Surveys
Coating holidays	2	1, 2	2	1, 2
Anodic zones on bare pipe	2	3	3	3
Near river or water crossing	2	2	2	2
Under frozen ground	3	3	3	1, 2
Stray currents	2	1, 2	2	1, 2
Shielded corrosion activity	3	3	3	3
Adjacent metallic structures	2	1, 2	3	1, 2
Near parallel pipelines	2	1, 2	3	1, 2
Under high-voltage alternating current (HVAC) overhead electric transmission lines	2	1, 2	2	2
Under paved roads	3	3	3	1, 2
Crossing other pipeline(s)	2	1, 2	2	1, 2
Cased piping	3	3	3	3
At very deep burial locations	3	3	3	3
Wetlands	2	1, 2	2	1, 2
Rocky terrain/rock ledges/rock backfill	3	3	3	2

[(A)]**Limitations and Detection Capabilities:** All survey methods are limited in sensitivity to the type and makeup of the soil, presence of rock and rock ledges, type of coating such as high dielectric tapes, construction practices, interference currents, and other structures. At least two or more survey methods may be needed to obtain desired results and confidence levels.

Shielding by Disbonded Coating: None of these survey tools is capable of detecting coating conditions that exhibit no electrically continuous pathway to the soil. If there is an electrically continuous pathway to the soil, such as through a small holiday or orifice, tools such as DCVG or current attenuation may detect these defect areas. This comment pertains to only one type of shielding from disbonded coatings. Current shielding, which may or may not be detectable with the indirect inspection methods listed, can also occur from other metallic structures and from geological conditions.

Pipe Depths: All of the survey tools are sensitive in the detection of coating holidays when pipe burials exceed normal depths. Field conditions and terrain may affect depth ranges and detection sensitivity.

KEY

1 = Applicable: Small coating holidays (isolated and typically < 600 mm^2 [1 in^2]) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.
2 = Applicable: Large coating holidays (isolated or continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.
3 = Applicable where the operator can demonstrate, through sound engineering practice and thorough analysis of the inspection location, that the chosen methodology produces accurate comprehensive results and results in a valid integrity assessment of the pipe being evaluated.

3.4.3.1 Soil resistivity information may be beneficial in interpreting the results of indirect inspection surveys, such as when evaluating changes in cathodic protection levels and when attempting to characterize the relative severity of a coating indication. Soil resistivity data may also be integrated with other data to assess the corrosiveness of the environment along the pipeline segment to provide a complementary indirect inspection tool, such as with a bare or poorly coated pipeline, as long as the requirements of Paragraph 3.4.3.2 are met.

3.4.3.2 The techniques included in Table 2 are not intended to illustrate the **only** inspection methods that are applicable or the capabilities of these inspection methods under all conditions. Rather, they are listed as representative examples of the types of indirect inspection methods available for an ECDA program. Other indirect inspection methods can and should be used as required by the unique situations along a pipeline or as new technologies are developed. In addition, the user should assess the capabilities of any method independently before incorporating it in an ECDA program.

3.4.3.3 The pipeline operator does not have to use the same indirect inspection tools at all locations along the pipeline segment. Figure 3 provides an example of how the selection of indirect inspection tools may vary along a segment.

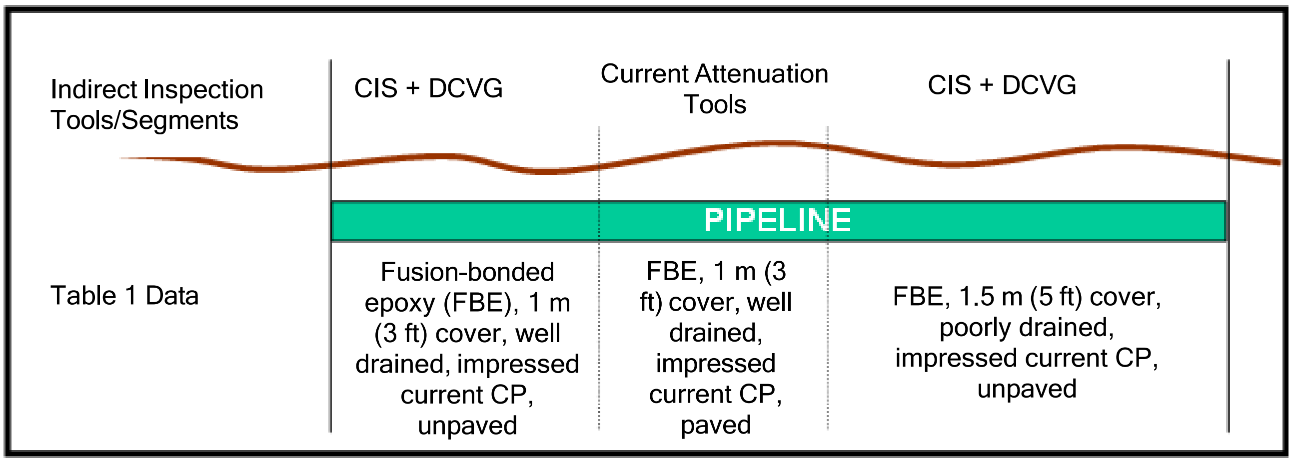

Figure 3: Example Selection of Indirect Inspection Tools

3.4.4 The pipeline operator must consider whether more than two indirect inspection tools are needed to detect corrosion activity reliably.

3.5 Identification of ECDA Regions

3.5.1 The pipeline operator shall analyze the data collected in the *Preassessment Step* to identify ECDA regions.

3.5.1.1 The pipeline operator should define criteria for identifying ECDA regions.

3.5.1.1.1 An ECDA region is a section or sections of a pipeline that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and in which the same indirect inspection tools are used.

3.5.1.1.2 The pipeline operator should consider all conditions that could significantly affect external corrosion when defining criteria for ECDA regions. Tables 1 and 2 may be used as guidance for establishing ECDA regions.

3.5.1.2 The definitions of ECDA regions may be modified based on results from the *Indirect Inspection Step* and the *Direct Examination Step*. The definitions made at this point are preliminary and are expected to be fine tuned later in the ECDA process.

3.5.1.3 A single ECDA region does not need to be contiguous. That is, an ECDA region may be broken along the pipeline, for example, if similar conditions are encountered on either side of a river crossing.

3.5.1.4 All of the pipeline segments should be included in ECDA regions.

3.5.2 Figure 4 gives an example definition of ECDA regions for a given pipeline.

3.5.2.1 The pipeline operator defined four distinct sets of physical characteristics and histories.

3.5.2.2 Based on the choice of indirect inspection tools, the soil characteristics, and the previous history, the pipeline operator defined six ECDA regions. Note that one region, ECDA 1, is not contiguous: two locations along the pipeline have the same soil characteristics, history, and indirect inspection tools and have therefore been categorized as the same region (ECDA 1).

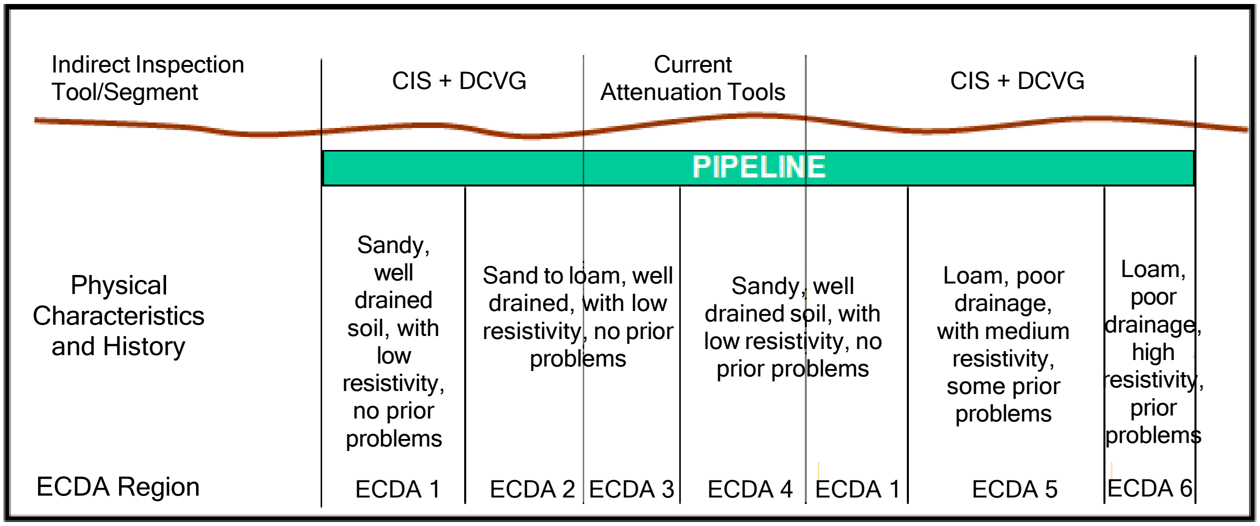

Figure 4: Example Definitions of ECDA Regions

Section 4: Indirect Inspection

4.1 Introduction

4.1.1 The objective of the *Indirect Inspection Step* is to identify and define the severity of coating faults, other anomalies, and areas at which corrosion activity may have occurred or may be occurring.

4.1.2 The *Indirect Inspection Step* requires the use of at least two at-grade or aboveground inspections over the entire length of each ECDA region and includes the following activities, as shown in Figure 5:

4.1.2.1 Performing indirect inspections in each ECDA region established in the *Preassessment Step;* and

4.1.2.2 Aligning and comparing of the data.

4.1.3 More than two indirect inspections may be required in any ECDA region (see Paragraph 4.3.3.1).

4.2 Indirect Inspection Measurements

4.2.1 Before performing the indirect inspection, the boundaries of each ECDA region identified in the *Preassessment Step* should be identified and clearly marked.

4.2.1.1 Measures to assure a continuous indirect inspection is achieved over the pipeline or segment being evaluated should be used. These measures may include some inspection overlap into adjacent ECDA regions.

4.2.2 Each indirect inspection shall be performed over the entire length of each ECDA region. Each indirect inspection must be performed and analyzed in accordance with generally accepted industry practices.

4.2.2.1 NACE SP0207 and NACE Standard TM0109 provide typical procedures for the indirect inspection tools listed in Table 2.

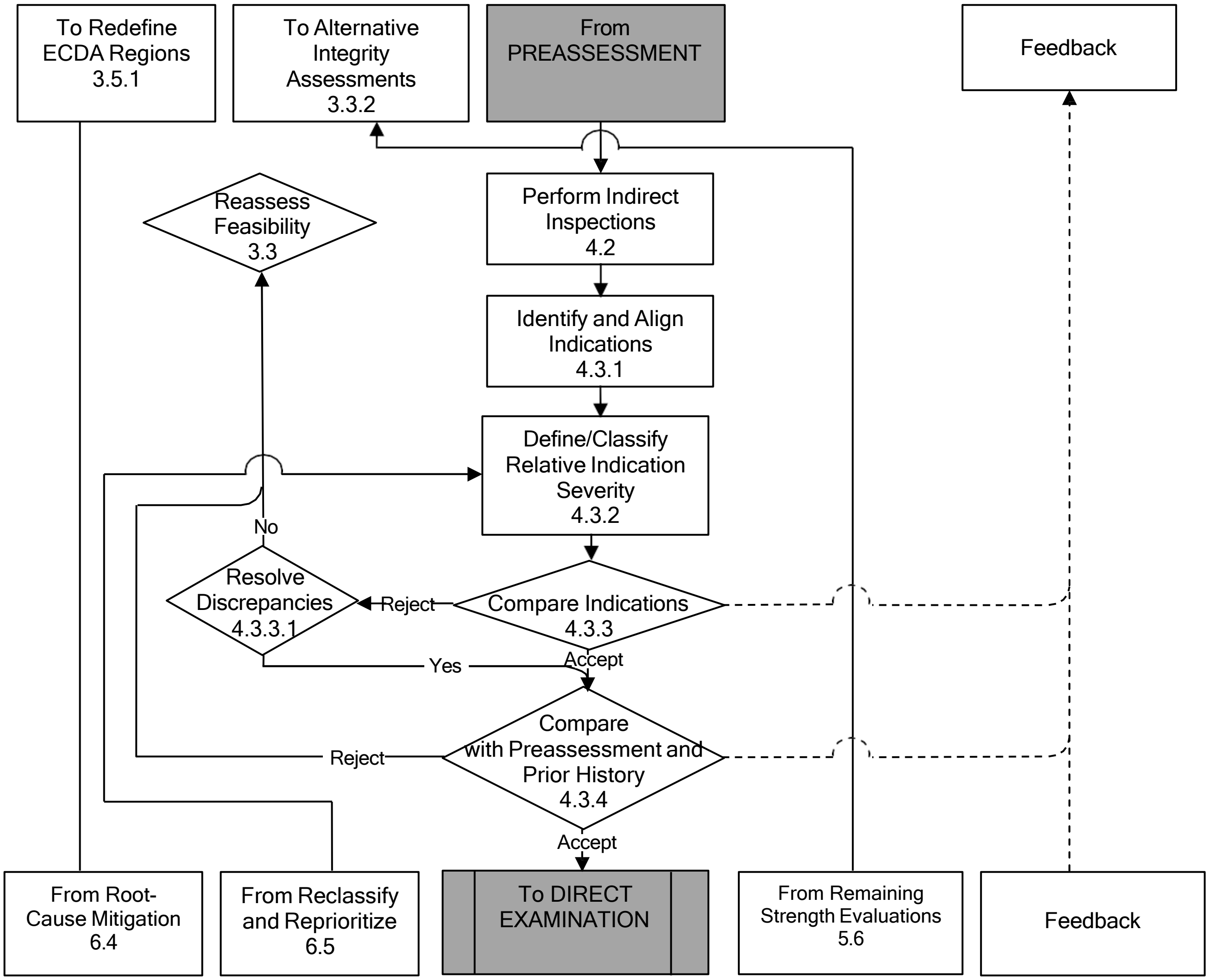

Figure 5: Indirect Inspection Step
(Numbers refer to paragraphs in this standard.)

4.2.2.2 When ECDA is applied for the first time, the pipeline operator should consider spot checking, repeating indirect inspections, or other verification means to ensure consistent data are obtained.

4.2.3 Indirect inspections shall be performed using intervals spaced closely enough to permit a detailed assessment. The distance selected must be such that the inspection tool can detect and locate suspected corrosion activity on the segment.

4.2.4 The indirect inspections should be performed as close together in time as practical.

4.2.4.1 If significant changes occur between the times of the indirect inspections, such as through a change of seasons or installation or abandonment of pipeline facilities, comparison of the results may be difficult or invalid.

4.2.5 Aboveground location measurements should be referenced to precise geographical locations (e.g., using global positioning systems [GPSs]) and documented so that inspection results can be compared and used to identify excavation locations.

4.2.5.1 Spatial errors cause difficulties when indirect inspection results are compared. Using a large number of aboveground reference points, such as fixed pipeline features and additional aboveground markers, reduces errors.

4.2.5.2 Commercially available software-based graphical overlay methods and similar techniques may be used to help resolve spatial errors.

4.3 Alignment and Comparison

4.3.1 After the indirect inspection data are taken, indications shall be identified and aligned for comparison.

4.3.1.1 The pipeline operator shall define criteria for identifying indications.

4.3.1.1.1 When applied to coated lines, the criteria for identifying indications should be sufficient to locate coating faults regardless of corrosion activity at the fault.

4.3.1.1.2 When applied to bare and poorly coated lines, the criteria for identifying indications should be sufficient to locate anodic regions.

4.3.1.2 When aligning indirect inspection results, the pipeline operator must consider the effect of spatial errors. The operator should consider whether two or more reported indication locations could be coincident as a result of spatial errors.

4.3.2 After identifying and aligning indications, the pipeline operator shall define and apply criteria for classifying the severity of each indication.

4.3.2.1 *Classification*, as used in this standard, is the process of estimating the likelihood of corrosion activity at an indirect inspection indication under typical year-round conditions. The following classifications may be used:

4.3.2.1.1 Severe—indications that the pipeline operator considers as having the highest likelihood of corrosion activity.

4.3.2.1.2 Moderate—indications that the pipeline operator considers as having possible corrosion activity.

4.3.2.1.3 Minor—indications that the pipeline operator considers inactive or as having the lowest likelihood of corrosion activity.

4.3.2.2 The criteria for classifying the severity of each indication should take into account the capabilities of the indirect inspection tool used and the unique conditions within an ECDA region.

4.3.2.3 When ECDA is applied for the first time, the pipeline operator should endeavor to make classification criteria as stringent as practicable. For example, indications for which the operator cannot determine whether corrosion is active should be classified as severe.

4.3.2.4 Table 3 gives example severity classification criteria for several indirect inspection methods. The examples given in Table 3 are meant as general, not absolute, criteria. The operator must consider the specific conditions along the pipeline when defining classification criteria.

Table 3
Example Severity Classification Criteria

Tool/Environment	Minor	Moderate	Severe
CIS, aerated moist soil	Small dips or on and off potentials above CP criteria	Medium dips or off potentials below CP criteria	Large dips or on and off potentials below CP criteria
DCVG, ACVG, or Pearson survey, similar conditions	Small indication	Medium indication	Large indication
Current Attenuation Surveys	Small increase in attenuation per unit length	Moderate increase in attenuation per unit length	Large increase in attenuation per unit length

4.3.3 After indications have been identified and classified, the pipeline operator shall compare the results from the indirect inspections to determine whether they are consistent.

4.3.3.1 If two or more indirect inspection tools indicate significantly different sets of locations at which corrosion activity may exist and if the differences cannot be explained by the inherent capabilities of the tools or specific and localized pipeline features or conditions, additional indirect inspections or preliminary direct examinations should be considered.

4.3.3.1.1 Preliminary direct examinations may be used to resolve discrepancies in lieu of additional indirect inspections, provided the direct examinations identify a localized and isolated cause of the discrepancy.

4.3.3.1.2 If preliminary direct examinations cannot be used to resolve the discrepancies, additional indirect inspections should be considered in accordance with Paragraph 3.4, after which the data must be aligned and compared as described above.

4.3.3.1.3 If additional indirect inspections are not performed or do not resolve the discrepancies, ECDA feasibility should be reassessed. As an alternative, the pipeline operator may use other proven integrity assessment technologies.

4.3.3.1.4 For initial ECDA applications to any pipeline segment, any location at which discrepancies cannot be resolved shall be categorized as severe.

4.3.4 After discrepancies have been resolved, the pipeline operator shall compare the results with the preassessment results and prior history for each ECDA region.

4.3.4.1 If the pipeline operator determines that the results from the indirect inspection are not consistent with the preassessment results and prior history, the operator should reassess ECDA feasibility and ECDA region definition. As an alternative, the pipeline operator may use other proven integrity assessment technologies.

Section 5: Direct Examination

5.1 Introduction

5.1.1 The objectives of the *Direct Examination Step* are to determine which indications from the indirect inspection step are most severe and collect data to assess corrosion activity.

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

5.1.3 A minimum of one dig is required regardless of the results of the indirect inspection and preassessment steps. Guidelines for determining the location and minimum number of excavations and direct examinations are given in Paragraph 5.3.

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.

5.1.5 During the *Direct Examination Step*, defects other than external corrosion may be found. While defects such as mechanical damage and SCC may be found, alternative methods must be considered for assessing the impact of such defect types. Alternative methods are given in ASME B31.4, ASME B31.8, ASME B31.8S, and API Std 1160.

5.1.6 The *Direct Examination Step* includes the following activities, as shown in Figure 6:

5.1.6.1 Prioritization of indications found during the indirect inspection step;

5.1.6.2 Excavations and data collection at areas where corrosion activity is most likely;

5.1.6.3 Measurements of coating damage and corrosion defects;

5.1.6.4 Evaluations of remaining strength (severity);

5.1.6.5 Analyses of discovered condition(s); and

5.1.6.6 A process evaluation.

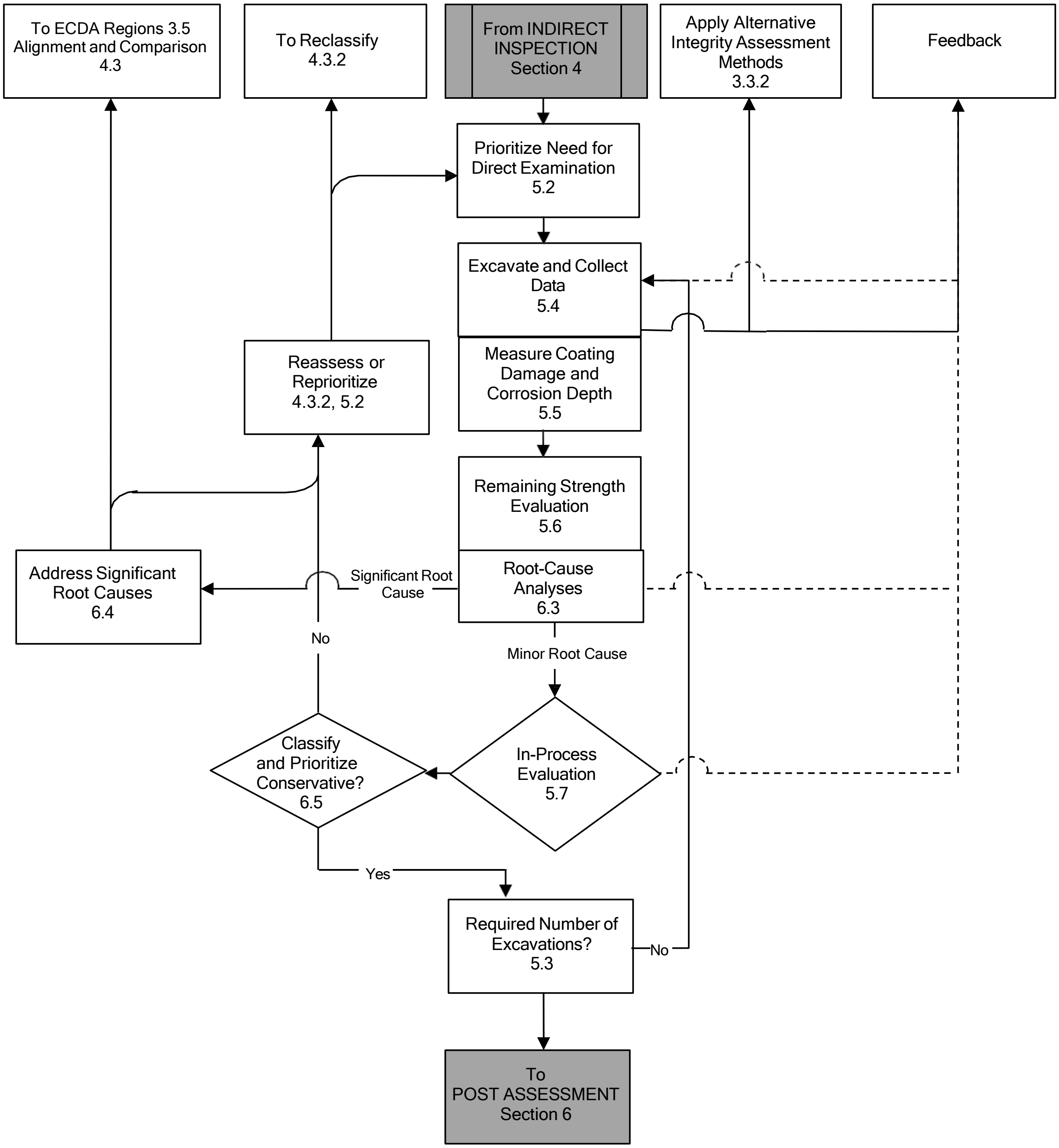

Figure 6: Direct Examination Step
(Numbers refer to paragraphs in this standard.)

5.2 Prioritization

5.2.1 The pipeline operator shall establish criteria for prioritizing the need for direct examination of each indication found during the *Indirect Inspection Step*.

5.2.1.1 *Prioritization*, as used in this standard, is the process of estimating the need to perform a direct examination at each indirect inspection indication based on current corrosion activity plus the extent and severity of prior corrosion. The three levels of priority are immediate, scheduled, and monitored, in this order.

5.2.1.2 Table 4 gives example prioritization criteria for indirect inspection indications. Different criteria may be required in different ECDA regions as a function of the pipeline condition, age, corrosion protection history, etc.

5.2.1.2.1 This standard does not establish time requirements for scheduling remediation and other actions that may be required by ECDA.

5.2.2 Minimum prioritization requirements are given for three priority categories as follows:

5.2.2.1 Immediate action required—this priority category should include indications that the pipeline operator considers as likely to have ongoing corrosion activity and that, when coupled with prior corrosion, pose an immediate threat to the pipeline under normal operating conditions.

5.2.2.1.1 Multiple severe indications in close proximity shall be placed in this priority category.

5.2.2.1.2 Isolated indications that are classified as severe by more than one indirect inspection tool at roughly the same location shall be placed in this priority category.

5.2.2.1.3 For initial ECDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results shall be placed in this priority category.

5.2.2.1.4 Consideration shall be given to placing other severe and moderate indirect inspection indications in this priority category if significant prior corrosion is suspected at or near the indication.

5.2.2.1.5 Indications for which the operator cannot determine the likelihood of ongoing corrosion activity should be placed in this priority category.

5.2.2.2 Scheduled action required—this priority category should include indications that the pipeline operator considers may have ongoing corrosion activity but that, when coupled with prior corrosion, do not pose an immediate threat to the pipeline under normal operating conditions.

5.2.2.2.1 Severe indications that are not in close proximity to other severe indications and which were not placed in the "immediate action required" category shall be placed in this priority category.

5.2.2.2.2 Consideration shall be given to placing moderate indications in this priority category, if significant or moderate prior corrosion is likely at or near the indication.

5.2.2.3 Suitable for monitoring—this priority category should include indications that the pipeline operator considers inactive or as having the lowest likelihood of ongoing or prior corrosion activity.

5.2.3 In setting these criteria, the pipeline operator shall consider the physical characteristics of each ECDA region under year-round conditions, the region's history of prior corrosion, the indirect inspection tools used, and the criteria used for identification and classification of indications.

5.2.3.1 When ECDA is applied for the first time, the pipeline operator should endeavor to make prioritization criteria as stringent as practicable. For example, indications for which the operator cannot estimate prior corrosion damage or determine whether corrosion is active should be categorized as immediate action required or scheduled action required.

Table 4
Example Prioritization Criteria for Indirect Inspection Indications

Immediate Action Required	Scheduled Action Required	Suitable for Monitoring
• Severe indications in close proximity regardless of prior corrosion. • Individual severe indications or groups of moderate indications in regions of moderate prior corrosion. • Moderate indications in regions of severe prior corrosion.	• All remaining severe indications. • All remaining moderate indications in regions of moderate prior corrosion. • Groups of minor indications in regions of severe prior corrosion.	• All remaining indications.

5.3 Guidelines for Determining the Required Number of Direct Examinations

5.3.1 No Indications Identified

5.3.1.1 In the event that no indications are identified in a pipeline segment, a minimum of one direct examination is required in the ECDA region identified as most likely for external corrosion in the *Preassessment Step*.

5.3.1.1.1 When ECDA is applied for the first time, one additional direct examination shall be performed in the ECDA region identified as most likely for external corrosion in the *Preassessment Step*.

5.3.1.2 If more than one ECDA region was identified as likely for external corrosion in the *Preassessment Step*, additional direct examinations should be considered.

5.3.1.2.1 The location(s) chosen for direct examination should be the location(s) identified in the *Preassessment Step* as most likely for external corrosion within the ECDA region.

5.3.2 Immediate Action Required

5.3.2.1 All indications that are prioritized as immediate action required require direct examination.

5.3.2.2 The need to perform direct examinations of indications that are reprioritized from immediate action required to scheduled action required may follow the guidelines for scheduled indications.

5.3.3 Scheduled Action Required

5.3.3.1 Some indications in the scheduled category require direct examination.

5.3.3.2 For each ECDA region that contains a scheduled indication(s), the operator must perform a direct examination of the most severe of scheduled indications. To determine the most severe of scheduled indications, an operator may prioritize the indications based on indirect inspection data, historical corrosion records, and current corrosive conditions.

5.3.3.2.1 When ECDA is applied for the first time, one additional direct examination shall be performed in each ECDA region containing scheduled indications. If a region contains only one scheduled indication, then the additional direct examination shall be at a monitored indication (or an indication as likely for external corrosion if no monitored indications exist).

5.3.3.3 If the external corrosion results of a direct examination at a scheduled indication are (1) deeper than 20% of the original wall thickness and (2) more severe (such as having a lower safe operating pressure) or deeper than corrosion discovered at an immediate indication within the same region, then at least one additional direct examination is required.

5.3.3.3.1 When ECDA is applied for the first time, one additional direct examination shall be performed.

5.3.4 Monitored Indications Are Identified

5.3.4.1 Indications in the monitored category may require direct examination.

5.3.4.2 If an ECDA region contains monitored indications and the ECDA region did not contain any immediate or scheduled indications, one direct examination is required in the ECDA region at the most severe indication.

5.3.4.2.1 When ECDA is applied for the first time, one additional direct examination shall be performed.

5.3.4.3 If multiple ECDA regions contain monitored indications and did not contain any immediate or scheduled indications, one direct examination is required in the ECDA region identified as most likely for external corrosion in the *Preassessment Step*.

5.3.4.3.1 When ECDA is applied for the first time, one additional direct examination shall be performed.

5.3.5 See Paragraph 6.7.2 for additional direct examination requirements.

5.4 Excavations and Data Collection

5.4.1 The pipeline operator shall make excavations based on the priority categories described in Paragraph 5.2. Guidelines for determining how many indications require excavation are provided in Paragraph 5.3.

5.4.1.1 The pipeline operator should geographically refer to the location for each excavation (e.g., using GPS) so that inspection and direct examination results can be directly compared.

5.4.2 Before excavation, the pipeline operator shall define minimum requirements for consistent data collection and record-keeping requirements in each ECDA region. Minimum requirements should be based on the pipeline operator's judgment.

5.4.2.1 Minimum requirements should include the types of data to be collected and take into account the conditions to be encountered, the types of corrosion activity expected, and the availability and quality of prior data.

5.4.3 Data Collection—Before Coating Removal

5.4.3.1 The pipeline operator should include data taken prior to excavation, during each excavation, and after excavation, but before coating removal.

5.4.3.2 Typical data measurements and related activities are as follows. NACE SP0207, NACE Standard TM0109, and Appendix A contain additional information.

5.4.3.2.1 Measurement of pipe-to-soil potentials;

5.4.3.2.2 Measurement of soil resistivity;

5.4.3.2.3 Soil sample collection;

5.4.3.2.4 Water sample collection;

5.4.3.2.5 Measurements of underfilm liquid pH;

5.4.3.2.6 Photographic documentation; and

5.4.3.2.7 Data for other integrity analyses—MIC, SCC, etc.

5.4.3.3 The pipeline operator should increase the size (length) of each excavation if conditions that indicate severe coating damage or significant corrosion defects beyond either side of the excavation are present.

5.5 Coating Damage and Corrosion Depth Measurements

5.5.1 The pipeline operator shall evaluate the condition of the coating and pipe wall at each excavation location.

5.5.2 Before making measurements, the pipeline operator shall define minimum requirements for consistent measurements and record-keeping requirements at each excavation.

5.5.2.1 Minimum requirements should include the types and accuracies of measurements to be made, taking into account the conditions to be encountered, the types of corrosion activity expected, and the availability and quality of prior measurement data.

5.5.2.2 For corrosion defects, minimum requirements should include evaluation of all significant defects. The parameters of such a defect should be defined in terms of the remaining strength calculation to be used.

5.5.3 Measurements

5.5.3.1 Typical measurements for evaluating the condition of the coating and the pipe are as follows. Appendix B contains additional information.

5.5.3.1.1 Identification of coating type;

5.5.3.1.2 Assessment of coating condition;

5.5.3.1.3 Measurement of coating thickness;

5.5.3.1.4 Assessment of coating adhesion;

5.5.3.1.5 Mapping of coating degradation (blisters, disbondment, etc.);

5.5.3.1.6 Corrosion product data collection;

5.5.3.1.7 Identification of corrosion defects;

5.5.3.1.8 Mapping and measurement of corrosion defects; and

5.5.3.1.9 Photographic documentation.

5.5.3.2 For initial ECDA applications, the pipeline operator should include all of the measurements listed in Paragraph 5.5.3.1.

5.5.3.3 Prior to identifying and mapping corrosion defects, the pipeline operator shall remove the coating and clean the pipe surface.

5.5.3.4 The pipeline operator shall measure and document all significant corrosion defects. Additional cleaning and pipe surface preparations should be made before depth and morphology measurements.

5.5.3.5 Other evaluations unrelated to external corrosion should be considered at this time. Such evaluations may include magnetic particle testing for cracks and ultrasonic thickness testing for internal defects.

5.6 Remaining Strength Evaluation

5.6.1 The pipeline operator shall evaluate or calculate the remaining strength at locations where corrosion defects are found. Commonly used methods of calculating the remaining strength include ASME B31G,[9] RSTRENG, and Det Norske Veritas (DNV)[(3)] Recommended Practice DNV-RP-F101.[10]

5.6.2 If the remaining strength of a defect is below the normally accepted level for the pipeline segment (e.g., the MAOP times a suitable factor for safety), a repair or replacement is required (or the MAOP may be lowered such that the MAOP times a suitable factor of safety is below the remaining strength). In addition, alternative methods of assessing pipeline integrity must be considered for the entire ECDA region in which the defect or defects were found, unless the defect or defects are shown to be isolated and unique in a root-cause analysis (see Paragraphs 6.3.1 and 6.3.2).

5.6.2.1 The ECDA process helps find representative corrosion defects on a pipeline segment, but it may not find all corrosion defects on the segment.

5.6.2.2 If corrosion defects that exceed allowable limits are found, it should be assumed that other similar defects may be present elsewhere in the ECDA region.

5.7 In-Process Evaluation

5.7.1 The pipeline operator shall perform an evaluation to assess the indirect inspection data and the results from the remaining strength evaluation and the analyses of discovered conditions.

5.7.2 The purpose of the evaluation is to assess the criteria used to categorize the need for repair (see Paragraph 5.2) and the criteria used to classify the severity of individual indications (see Paragraph 4.3.2).

5.7.3 Assess prioritization criteria

5.7.3.1 The pipeline operator shall assess the extent and severity of existing corrosion relative to the assumptions made in establishing priority categories for repair (see Paragraph 5.2).

5.7.3.2 If existing corrosion is less severe than prioritized in Paragraph 5.2, the pipeline operator may modify the criteria and reprioritize all indications.

5.7.3.3 If existing corrosion is more severe than prioritized, the pipeline operator shall modify the criteria and reprioritize all indications.

---

(3) Det Norske Veritas (DNV), Veritasveien 1, 1363 Høvik, Oslo, Norway.

5.7.3.4 Any indication for which comparable direct examination measurements show more serious conditions than suggested by the indirect inspection data shall be moved to a more severe priority category.

5.7.4 Assess classification criteria

5.7.4.1 The pipeline operator shall assess the corrosion activity at each excavation relative to the criteria used to classify the severity of indications (see Paragraph 4.3.2).

5.7.4.2 If the corrosion activity is less severe than classified, the pipeline operator may reassess and adjust the criteria used to define the severity of all indications. In addition, the pipeline operator may reconsider and adjust the criteria used to prioritize the need for repair. For initial ECDA applications, the pipeline operator should not downgrade any classification or prioritization criteria.

5.7.4.3 If the corrosion activity is worse than classified, the pipeline operator shall reassess and appropriately adjust the criteria used to define the severity of all indications.

5.7.4.3.1 In addition, the pipeline operator shall consider the need for additional indirect inspections and reconsider and adjust the criteria used to prioritize the need for repair.

5.7.4.4 If repeated direct examinations show corrosion activity that is worse than indicated by the indirect inspection data, the pipeline operator should reevaluate the feasibility of successfully using ECDA.

5.7.5 Throughout the ECDA process, if the pipeline operator identifies conditions on the pipeline for which ECDA is not well suited, then the operator shall address those conditions and determine whether ECDA remains applicable.

Section 6: Post Assessment

6.1 Introduction

6.1.1 The objectives of the *Postassessment Step* are to define reassessment intervals, determine whether or not to reprioritize indications, and assess the overall effectiveness of the ECDA process.

6.1.2 Reassessment intervals shall be defined on the basis of scheduled indications.

6.1.2.1 All immediate indications shall have been addressed during direct examinations.

6.1.2.2 Monitored indications are expected to experience insignificant growth.

6.1.3 The conservatism of the reassessment interval is not easy to measure, because there are uncertainties in the remaining defect sizes, the maximum corrosion growth rates, and the periods of a year in which defects grow by corrosion. To account for these uncertainties, the reassessment interval defined herein is based on a half-life concept. An estimate of the true life is made, and the reassessment interval is set at one-half that value.

6.1.3.1 Basing reassessment intervals on a half-life concept is commonly used in sound engineering practice.[1]

6.1.3.2 The estimate of true life is based on conservative growth rates and conservative growing periods.

6.1.3.3 To ensure unreasonably long reassessment intervals are not used, the pipeline operator should define a maximum reassessment interval that cannot be exceeded unless all indications are addressed. Documents such as ASME B31.4, ASME B31.8, ASME B31.8S, and API Std 1160 may provide guidance.

6.1.4 The *Postassessment Step* includes the following activities, as shown in Figure 7.

6.1.4.1 Root-cause analysis;

6.1.4.2 Determining mitigation;

6.1.4.3 Reprioritization;

6.1.4.4 Remaining life calculations;

6.1.4.5 Definition of reassessment intervals;

6.1.4.6 Assessment of ECDA effectiveness; and

6.1.4.7 Feedback and continuous improvement.

6.2 Remaining Life Calculations

6.2.1 If no corrosion defects are found, no remaining life calculation is needed: the remaining life may be taken as the same as for a new pipeline.

6.2.2 The maximum remaining defect size at all scheduled indications shall be taken as the same as the most severe indication in all locations that have been excavated (see Section 5).

6.2.2.1 If the root-cause analyses indicate that the most severe indication is unique, the size of the next most severe indication may be used for the remaining life calculations.

6.2.2.2 As an alternative, a pipeline operator may substitute a different value based on a statistical or more sophisticated analysis of the excavated severities.

6.2.3 The corrosion growth rate shall be based on sound engineering practice.

6.2.3.1 When the operator has measured corrosion rate data that are applicable to the ECDA region(s) being evaluated, actual rates may be used.

6.2.3.2 In the absence of measured corrosion rate data, the values and methods provided in Appendix C should be used for growth rate estimates. These corrosion rates have been based on the free corrosion of ferrous material in various soil types.

6.2.4 The remaining life of the maximum remaining defect shall be estimated using a sound engineering practice.

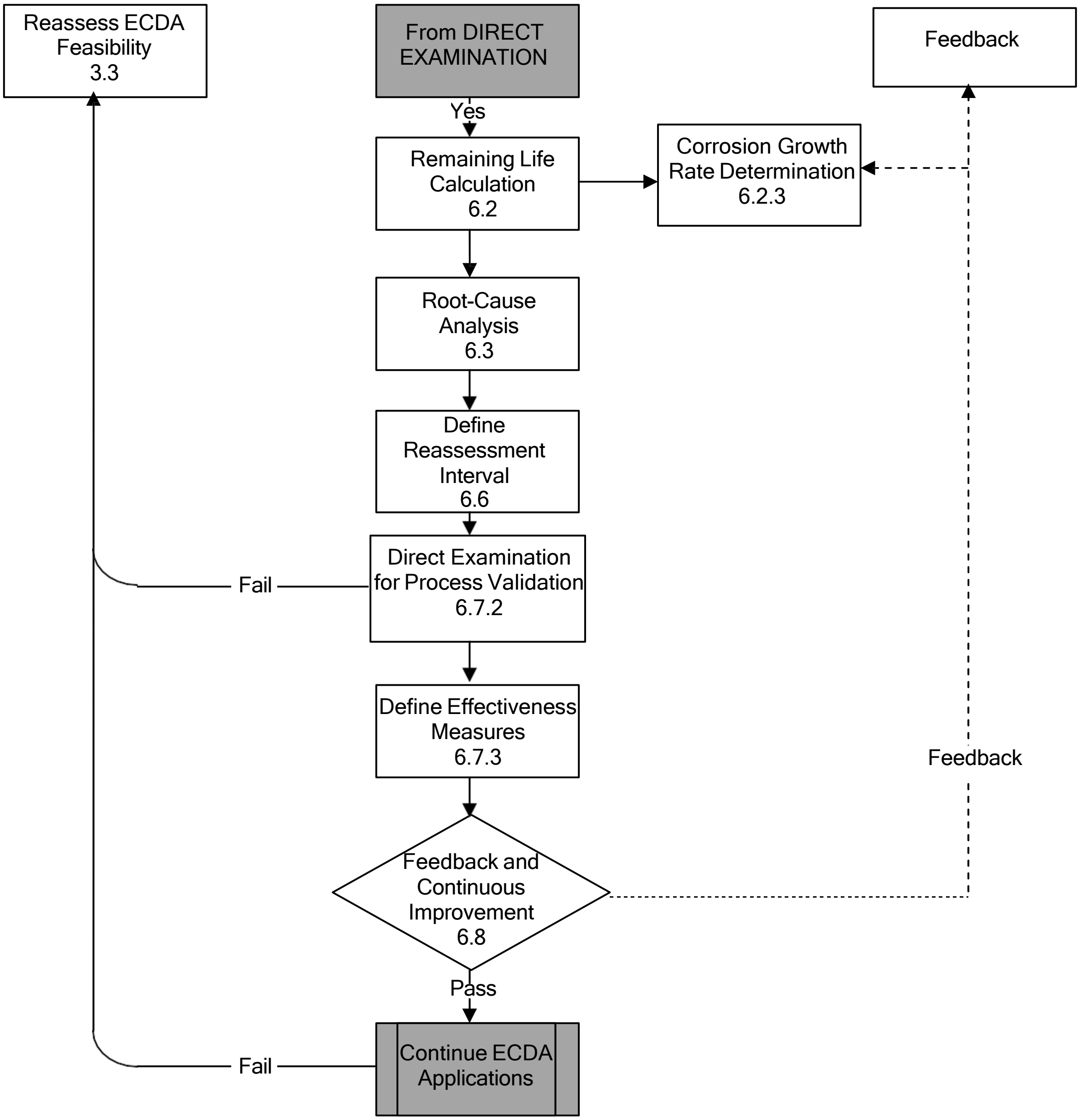

Figure 7: Postassessment Step
(Numbers refer to paragraphs in this standard.)

6.2.4.1 In the absence of an alternative analysis method, the method shown in Equation (1) may be used to calculate the remaining life.

$$RL = C \times SM \frac{t}{GR} \tag{1}$$

where:

C = Calibration factor = 0.85 (dimensionless)
RL = Remaining life (y)
SM = Safety margin = Failure pressure ratio – MAOP ratio (dimensionless)
Failure pressure ratio = Calculated failure pressure/yield pressure (dimensionless)
MAOP ratio = MAOP/yield pressure (dimensionless)
t = Nominal wall thickness (mm [in])
GR = Growth rate (mm/y [in/y])

6.2.4.2 This method of calculating expected remaining life is based on corrosion that occurs continuously and on typical sizes and geometries of corrosion defects. It is considered conservative for external corrosion on pipelines.

6.3 Root-Cause Analysis

6.3.1 The pipeline operator shall identify any existing root causes of all significant corrosion activity found during direct examination. This may include inadequate CP current, previously unidentified sources of interference, or other situations that are isolated and unique.

6.3.2 If the pipeline operator uncovers a root cause for which ECDA is not well suited (e.g., shielding by disbonded coating or MIC), the pipeline operator shall consider alternative methods of assessing the integrity of the pipeline segment.

6.4 Mitigation

6.4.1 The pipeline operator shall identify and perform remediation activities to mitigate or preclude future external corrosion resulting from significant root causes.

6.4.1.1 The pipeline operator may choose to repeat indirect inspections after remediation activities.

6.4.1.2 The pipeline operator may reprioritize indications based on remediation activities, as described in Paragraph 6.5.

6.5 Reclassification and Reprioritization

6.5.1 In accordance with Paragraph 5.7.3, reprioritization is required when existing corrosion is more severe than estimated in Paragraph 5.2.

6.5.1.1 In general, an indication that was originally placed in the immediate action required category should be moved no lower than the scheduled action required category as a result of reprioritization.

6.5.1.2 When ECDA is applied for the first time, the pipeline operator should not downgrade any indications that were originally placed in the immediate action required or scheduled action required priority category.

6.5.2 In accordance with Paragraph 5.7.4, reclassification is required when results from the direct examination show corrosion activity that is worse than indicated by indirect inspection data.

6.5.3 In addition, for each root cause, the pipeline operator shall identify and reevaluate all other indications that occur in the pipeline segment where similar root-cause conditions exist.

6.5.4 If a repair and recoating or replacement is performed, the indication is no longer a threat to the pipeline and may be removed from further consideration after completion of the required root-cause analysis and mitigation activities.

6.5.5 If remediation is performed, an indication that was initially placed in the immediate action required priority category may be moved to the scheduled action required priority category, provided subsequent indirect inspections justify reducing the indication severity.

6.5.6 If remediation is performed, an indication that was initially placed in the scheduled action required priority category may be moved to the suitable for monitoring priority category, if subsequent indirect inspections justify reducing the indication severity.

6.6 Reassessment Intervals

6.6.1 When corrosion defects are found during the direct examinations, the maximum reassessment interval for each ECDA region shall be taken as one-half the calculated remaining life. The maximum reassessment interval may be further limited by documents such as ASME B31.4, ASME B31.8, and ASME B31.8S.

6.6.2 Different ECDA regions may have different reassessment intervals based on variations in expected growth rates between ECDA regions.

6.6.3 Any indications prioritized as “scheduled action required” that were not excavated or remediated during the direct examination step and that remain as scheduled action required after reprioritization should be addressed before the end of the reassessment interval. The term “addressed” means the operator has taken some remedial action such that the indications prioritized as “scheduled action required” are no longer in this category. Remedial actions could include adding CP or recoating.

6.7 Assessment of ECDA Effectiveness

6.7.1 ECDA is a continuous improvement process. Through successive ECDA applications, a pipeline operator should be able to identify and address locations at which corrosion activity has occurred, is occurring, or may occur.

6.7.2 At least one additional direct examination at a randomly selected location shall be performed to provide additional confirmation that the ECDA process has been successful.

6.7.2.1 For initial ECDA applications, at least two additional direct examinations are required for process validation. The direct examinations shall be performed at randomly selected locations, one of which contains a scheduled indication (or monitored indication if no scheduled indications exist) and one in an area where no indication was detected.

6.7.2.2 If conditions that are more severe than determined during the ECDA process (i.e., that result in a reassessment interval less than determined during the ECDA process) are detected, the process shall be reevaluated and repeated or an alternative integrity assessment method used.

6.7.3 The pipeline operator shall establish additional criteria for assessing the long-term effectiveness of the ECDA process.

6.7.3.1 An operator may choose to establish criteria that track the reliability or repeatability with which the ECDA process is applied. For example, an operator may track the number of reclassifications and reprioritizations that occur during an ECDA process. A significant percentage of indications that are reclassified or reprioritized indicates the criteria established by the operator may have been unreliable.

6.7.3.2 An operator may choose to establish criteria that track the application of the ECDA process. Following are examples:

6.7.3.2.1 An operator may track the number of excavations made to investigate potential problems. An increase in excavations indicates more aggressive corrosion monitoring.

6.7.3.2.2 An operator may track the total number of kilometers (miles) of pipeline that are subjected to multiple indirect inspections. An increase in the number of kilometers (miles) inspected indicates the need for more aggressive corrosion monitoring.

6.7.3.2.3 Similarly, an operator may track the number of kilometers (miles) subjected to each indirect inspection methodology, seeking to increase the number of kilometers (miles) used by the methods that prove most effective on the operator's system. An increase in the use of techniques that are most effective indicates a more focused ECDA application.

6.7.3.3 An operator may choose to establish criteria that track the results of the ECDA process. Following are examples:

6.7.3.3.1 The operator may choose to assess effectiveness by comparing the frequency at which immediate and scheduled indications arise. A reduction in frequency indicates an improved net management of corrosion.

6.7.3.3.2 The operator may monitor the extent and severity of corrosion found during direct examinations. A decrease in extent and severity indicates a reduction in the impact of corrosion on the structural integrity of a pipeline.

6.7.3.3.3 The operator may monitor the frequency at which CP anomalies occur along pipeline segments. A decrease in anomalies indicates better management of the CP system.

6.7.3.4 An operator may choose to establish absolute criteria. For example, the operator may establish a minimum performance requirement that no leak or rupture as a result of external corrosion occurs after an ECDA application and before the next reassessment interval. Meeting such a criterion demonstrates integrity with regard to corrosion.

6.7.4 In the event that evaluation does not show improvement between ECDA applications, the pipeline operator should reevaluate the ECDA application or consider alternative methods of assessing pipeline integrity.

6.8 Feedback and Continuous Improvement

6.8.1 Throughout the ECDA process as well as during scheduled activities and reassessments, the pipeline operator shall endeavor to improve the ECDA applications by incorporating feedback at all appropriate opportunities.

6.8.2 Activities for which feedback should be considered include:

6.8.2.1 Identification and classification of indirect inspection results (see Paragraphs 4.3.2 through 4.3.4);

6.8.2.2 Data collection from direct examinations (see Paragraphs 5.4 and 5.5);

6.8.2.3 Remaining strength analyses (see Paragraph 5.6);

6.8.2.4 Root-cause analyses (see Paragraph 6.3);

6.8.2.5 Remediation activities (see Paragraph 6.4);

6.8.2.6 In-process evaluations (see Paragraph 5.7);

6.8.2.7 Direct examinations used for process validation (see Paragraph 6.7.2);

6.8.2.8 Criteria for monitoring long-term ECDA effectiveness (see Paragraph 6.7.3); and

6.8.2.9 Scheduled monitoring and period reassessments.

Section 7: ECDA Records

7.1 Introduction

This section describes ECDA records that document in a clear, concise, workable manner data that are pertinent to preassessment, indirect inspection, direct examination, and postassessment.

7.2 Preassessment

7.2.1 All preassessment actions should be recorded. This may include, but is not limited to, the following:

7.2.1.1 Data elements collected for the segment to be evaluated, in accordance with Table 1;

7.2.1.2 Methods and procedures used to integrate the data collected to determine when indirect inspection tools can and cannot be used;

7.2.1.3 Methods and procedures used to select the indirect inspection tools; and

7.2.1.4 Characteristics and boundaries of ECDA regions and the indirect inspection tools used in each region.

7.3 Indirect Inspection

7.3.1 All indirect inspection actions should be recorded. This may include, but is not limited to, the following:

7.3.1.1 Geographically referenced locations of the beginning and ending point of each ECDA region and each fixed point used for determining the location of each measurement;

7.3.1.2 Date(s) and weather conditions under which the inspections were performed;

7.3.1.3 Inspection results at sufficient resolution to identify the location of each indication;

7.3.1.3.1 When data are not recorded in a (near) continuous manner, a complete description of the conditions between the locations of indications (epicenters).

7.3.1.4 Procedures for aligning data from the indirect inspections and expected errors for each inspection tool; and

7.3.1.5 Procedures for defining the criteria to be used in prioritizing the severity of the indications.

7.4 Direct Examination

7.4.1 All direct examination actions should be recorded. This may include, but is not limited to, the following:

7.4.1.1 Procedures and criteria for prioritizing the indirect inspection indications;

7.4.1.2 Data collected before and after excavation;

7.4.1.2.1 Measured metal-loss corrosion geometries;

7.4.1.2.2 Data used to identify other areas that may be susceptible to corrosion;

7.4.1.2.3 Data used to estimate corrosion growth rates;

7.4.1.3 Results of root-cause identifications and analyses, if any;

7.4.1.4 Planned remediation activities; and

7.4.1.5 Descriptions of and reasons for any reprioritizations.

7.5 Postassessment

7.5.1 All postassessment actions should be recorded. This may include, but is not limited to, the following:

7.5.1.1 Remaining life calculation results;

7.5.1.1.1 Maximum remaining defect size determinations;

7.5.1.1.2 Corrosion growth rate determinations;

7.5.1.1.3 Method of estimating remaining life;

7.5.1.1.4 Results;

7.5.1.2 Reassessment intervals and scheduled activities, if any;

7.5.1.3 Criteria used to assess ECDA effectiveness and results from assessments;

7.5.1.3.1 Criteria and metrics;

7.5.1.3.2 Data from periodic assessments;

7.5.1.4 Feedback;

7.5.1.4.1 Assessment of criteria used in each step of the ECDA process; and

7.5.1.4.2 Modifications of criteria.

References

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

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

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

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

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

6. NACE Standard TM0109 (latest revision), “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition” (Houston, TX: NACE).

7. 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) (Washington, DC: PRCI,[5] 1993).

8. J.M. Pearson, “Electrical Instruments and Measurement in Cathodic Protection,” *CORROSION* 3, 11 (1947): p. 549.

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

10. DNV Recommended Practice DNV-RP-F101 (latest revision), “Corroded Pipelines” (Oslo, Norway: Det Norske Veritas).

11. NACE Standard TM0497 (latest revision), “Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems” (Houston, TX: NACE).

12. ASTM[6] G57, “Standard Test Method for Field Measurement of Soil Resistivity Using the Wenner Four-Electrode Method” (West Conshohocken, PA: ASTM).

13. ASTM D2487 (latest revision), “Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)” (West Conshohocken, PA: ASTM).

14. AASHTO[7] Method T265 (latest revision), “Standard Method of Test for Laboratory Determination of Moisture Content of Soils” (Washington, DC: AASHTO).

15. EPA[8] Method 376.1 (latest revision), “Sulfide (Titrimetric, Iodine)” (Washington, DC: EPA).

---

(4) American National Standards Institute (ANSI), 25 West 43rd St., 4th Floor, New York, NY 10036.
(5) Pipeline Research Council International, Inc. (PRCI), 3141 Fairview Park Drive, Suite 525, Falls Church, VA 22042.
(6) ASTM International (ASTM), 100 Barr Harbor Dr., West Conshohocken, PA 19428-2959.
(7) American Association of State Highway and Transportation Officials (AASHTO), 444 N. Capitol St. NW, Suite 249, Washington, DC 20001.
(8) U.S. Environmental Protection Agency (EPA), Ariel Rios Building, 1220 Pennsylvania Ave. NW, Washington, DC 20460.

16. ASTM G51 (latest revision), "Standard Test Method for Measuring pH of Soil for Use in Corrosion Testing" (West Conshohocken, PA: ASTM).

17. ASTM D512 (latest revision), "Standard Test Methods for Chloride Ion in Water" (West Conshohocken, PA: ASTM).

18. ASTM D516 (latest revision), "Standard Test Method for Sulfate Ion in Water" (West Conshohocken, PA: ASTM).

19. NACE Standard TM0106 (latest revision), "Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines" (Houston, TX: NACE).

20. NACE SP0169 (formerly RP0169) (latest revision), "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" (Houston, TX: NACE).

21. M. Romanoff, *Underground Corrosion* (Houston, TX: NACE, 1969 [reprinted 1989]).

22. ASTM G59 (latest revision), "Standard Test Method for Conducting Potentiodynamic Polarization Resistance Measurements" (West Conshohocken, PA: ASTM).

23. M. Stern, A.S. Geary, *Journal of the Electrochemical Society* 104, 1 (1957).

24. ASTM G102 (latest revision), "Standard Practice for Calculation of Corrosion Rates and Related Information from Electrochemical Measurements" (West Conshocken, PA: ASTM).

25. NACE Standard TM0169 (latest revision), "Laboratory Corrosion Testing of Metals" (Houston, TX: NACE).

Bibliography

API Specification 5L (latest revision), "Specification for Line Pipe" (Washington, DC: API).

API 510 (latest revision), "Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration" (Washington, DC: API).

Baboian, R. *Corrosion Tests and Standards: Application and Interpretation*, 2nd ed. Houston, TX: NACE, 2004.

GPTC ANSI Technical Report, "Review of Integrity Management for Natural Gas Transmission Pipelines." Washington, DC: American Gas Association (AGA), 2001.

Lawson, K.M., and N.G. Thompson. "The Use of Coupons for Monitoring the Cathodic Protection of Buried Structures." CORROSION/98, paper no. 672. Houston, TX: NACE, 1998.

NACE SP0102 (formerly RP0102) (latest revision). "In-Line Inspection of Pipelines." Houston, TX: NACE.

NACE Publication 35100 (latest revision). "In-Line Nondestructive Inspection of Pipelines." Houston, TX: NACE.

NACE Publication 3T199 (latest revision). "Techniques for Monitoring Corrosion and Related Parameters in Field Applications." Houston, TX: NACE.

Peabody's Control of Pipeline Corrosion, 2nd ed. R. Bianchetti, ed. Houston, TX: NACE, 2001.

U.S. Code of Federal Regulations (CFR) Title 49, Part 192 (latest revision). "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards." Washington, DC: Office of the Federal Register.

U.S. CFR Title 49, Part 195 (latest revision). Transportation of Hazardous Liquids by Pipeline. Washington, DC: Office of the Federal Register.

Appendix A[9]
Direct Examination—Data Collection Methods Before Coating Removal
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

A1 Safety Considerations

Excavating and working around pressurized pipe involves potential risks. Appropriate safety precautions, such as those included in industry standards, government regulations, and company procedures, should be followed.

A2 Pipe-to-Soil Potentials

A2.1 Pipe-to-soil potential measurements should be made in accordance with NACE Standard TM0497.[11]

A2.2 Pipe-to-soil potentials should be measured with the reference electrode placed in the bank of the excavation, at various positions around the pipe, in the side of the excavation, and/or at the surface. These measurements are for information purposes only, because with the excavation of the pipe, the electric field around the pipe has been altered. Pipe-to-soil potentials at the point of excavation may help to identify dynamic stray currents in the area.

A3 Measurement of Soil Resistivity

A3.1 Four-Pin Method (Wenner)[12]

A3.1.1 When this method is used, four pins are placed at equal distance in the earth in a straight line as shown in Figure A1. The spacing of the pins (shown as "a") must equal the depth to which the soil resistivity is of interest. A current is caused to flow between the two outside pins (C1 and C2). The voltage drop created in the earth by this current flow is measured between the two inside pins (P1 and P2).

---

(9) The original Appendix A titled "Indirect Inspection Methods" in the 2002 and 2008 editions of this standard has been deleted from this 2010 edition. Information on indirect inspection methods can be found in NACE Standard TM0109 and NACE SP0207.

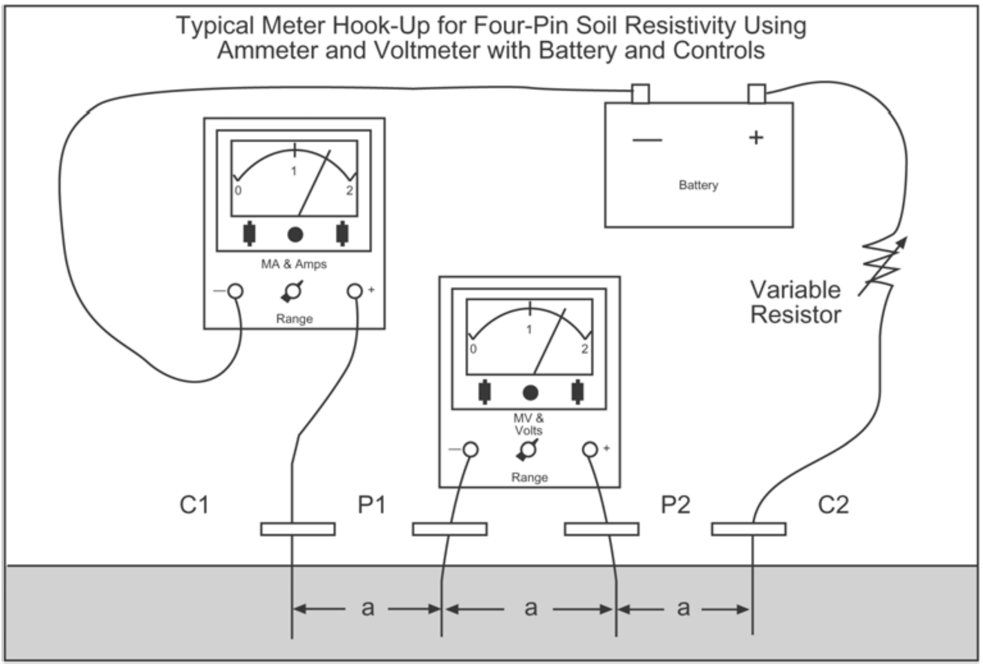

Figure A1: Four-Pin Method with Voltmeter and Ammeter

A3.1.2 There are two distinct differences in the apparatus used with the four-pin method. The first, as shown in Figure A1, is performed with an ammeter and voltmeter combination. This combination uses direct current (DC) to produce and measure the voltage drop in the earth between the inside pins (P1 and P2). The second, as shown in Figure A2, uses a galvanometer that generally uses a vibrator circuit. The use of a galvanometer is believed to be more accurate because no polarization of the electrodes should occur. In practice, both configurations should give accurate and reproducible results, provided that excessive currents and voltages are not used.

A3.1.3 Care and judgment must be exercised under certain conditions in which pin contact resistance with the earth may be high. High resistance at the pin contacts may affect the measurement accuracy, and with the alternating current (AC) equipment, the galvanometer does not zero correctly. This condition generally occurs during dry weather periods and in locations of relatively high soil resistivity. When using the galvanometer, the needle should swing to both sides of zero. Wetting of the soil around the current pins with water or a water/soap solution may eliminate or reduce the effects of this condition. Pins should be inserted into the ground as little as possible and still obtain readings. Pins should never be inserted to a depth greater than 10% of pin spacing. Equation (A1) is based on a theoretical point contact.

A3.1.4 The average soil resistivity to a depth equal to the spacing between the two inside pins is given by Equation (A1):[12]

$$\rho = 2\pi aR \quad (\text{for "a" in cm}) \tag{A1a}$$

$$\rho = 191.5\,aR \quad (\text{for "a" in ft}) \tag{A1b}$$

Where:

ρ = Resistivity in Ω·cm
a = Pin spacing in cm (ft)
R = Resistance in Ω = V/I
V = Potential in V
I = Current in A

A3.1.5 When a galvanometer instrument such as that shown in Figure A2 is used, the resistance (R) can be read directly. The galvanometer-type instrument uses a Wheatstone bridge circuit and when balanced to zero, shows R directly on the balancing controls or, as in this case, may require a simple multiplication between the control indications on the instrument.

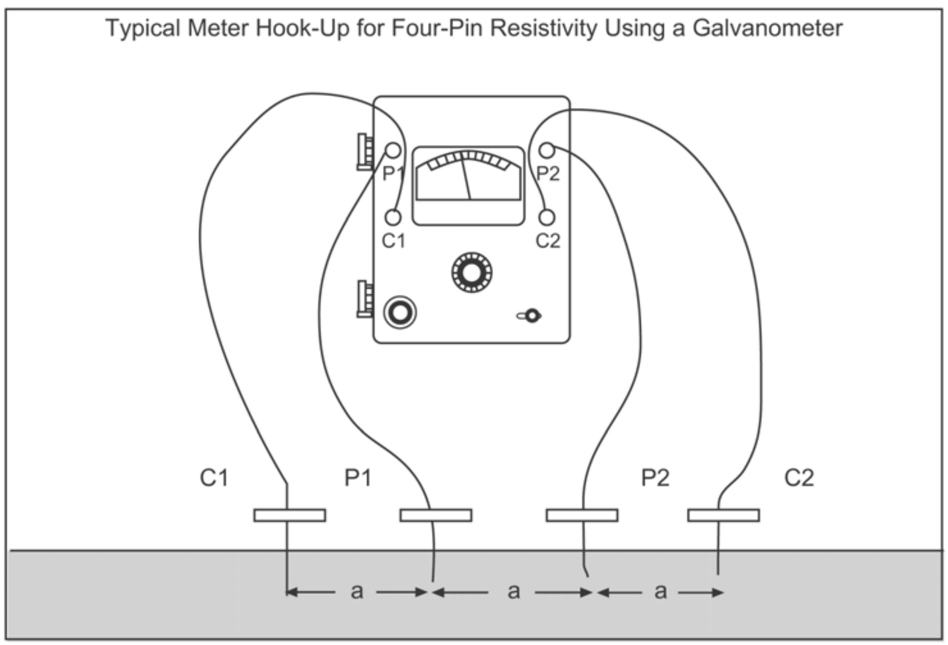

Figure A2: Four-Pin Method with Galvanometer

A3.1.6 The four-pin method is used for most field resistivity measurements of soils. Soil resistivity determined in this manner is the average (or apparent) soil resistivity of a hemisphere of earth. This is illustrated in Figure A3, which shows that the radius of this hemisphere is distance "a" (the distance between the inside pins). If a steel pipeline or other metallic structure lies within the sphere to be measured, measurement errors result. To avoid these errors, readings should be taken perpendicular to the pipeline with the nearest pin no closer than ½ "a" to the pipe (or any other metallic structure).

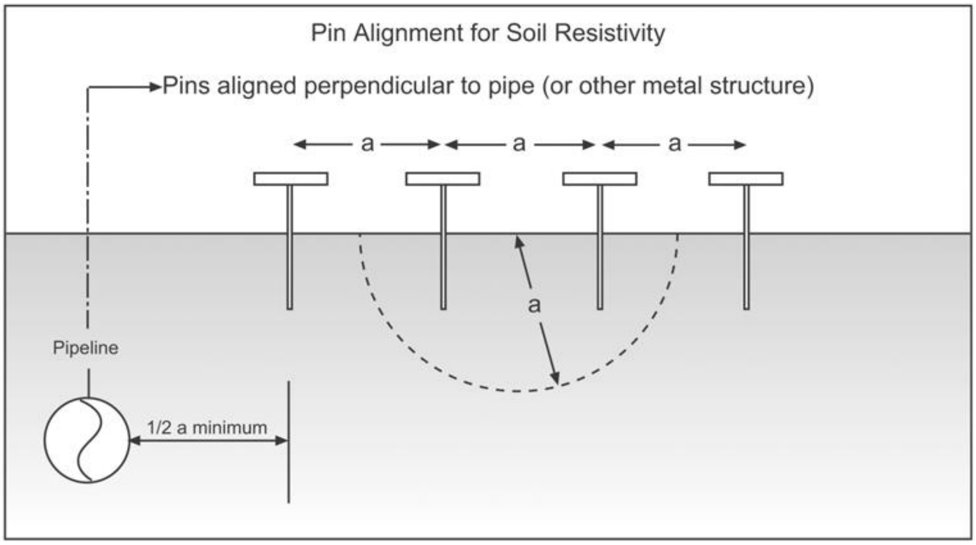

Figure A3: Pin Alignment Perpendicular to Pipe

The pin spacing must be of equal distance to obtain accurate results. For general use, a pin spacing of 1.6 m (5 ft, 3 in) is convenient because this results in a factor (191.5 times "a") being equal to 1,000.

A3.1.7 Readings taken with successively greater pin spacing give a profile of the average soil resistivity of an increasingly larger hemisphere, and thus to a greater depth. It should be noted in the analysis of increasingly larger pin spacing that in the case of relatively the same soil resistivity with depth, the soil resistivity as measured decreases slightly. An increase in the measured resistivity tends to suggest that the soil resistivity is increasing with depth more than is indicated by the measured amount. The opposite is true for large reductions in resistivity. These tend to indicate a lower than measured resistivity with depth. For each successively greater pin spacing, a greater depth in the soil is included in the measurement; but because this is a surface type of measurement method, it also includes the resistivity of the soil layers above.

A3.2 Soil Box Method[12]

Figure A4 shows another use of the four-pin method in conjunction with a soil box. The soil box is primarily used for resistivity measurements during excavations or boring. The connection of the instrument and test procedure is essentially the same as those illustrated earlier. They are suited for testing resistivity at varying levels of depth during vertical bores because they allow measurement of various strata of soil as the boring progresses. Also, data can be measured from soil taken at pipeline depth during the installation of a new pipeline. Accuracy of a soil box depends on how closely the original conditions are recreated in the soil box (e.g., compaction, moisture). The soil box has a multiplier for obtaining soil resistivity. Always refer to the manufacturer's instructions for use of a multiplier.

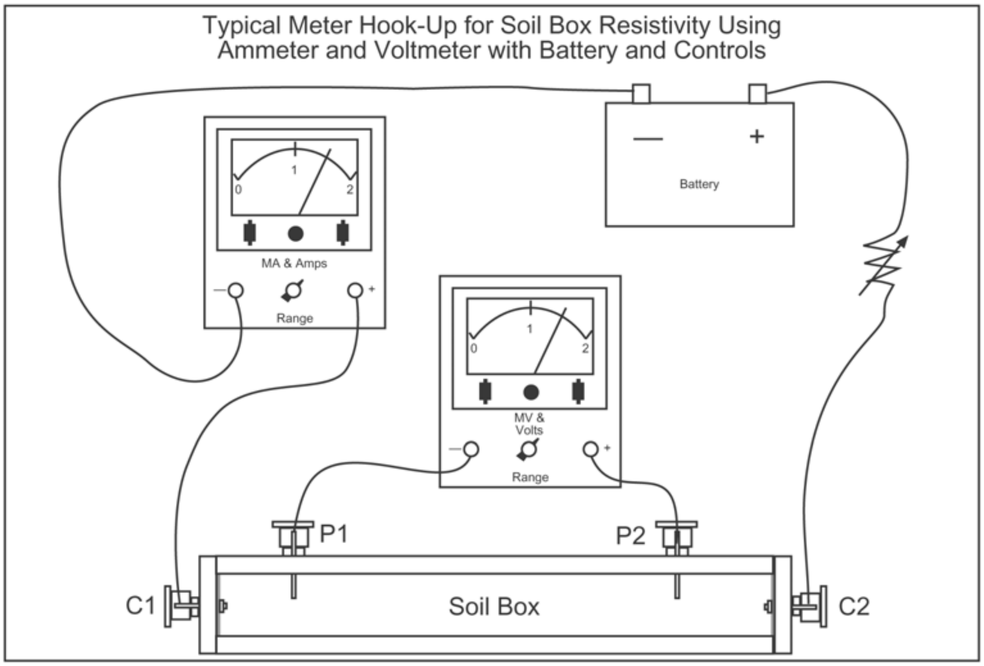

Figure A4: Soil Box Resistivity

A3.3 Single-Probe Method

A3.3.1 The single-probe method is a two-point resistivity measurement. The typical probe is shown in Figure A5 with an audio-type instrument. A resistance measurement is made between the tip of the probe and the shank of the probe rod after insertion in the soil. Modern models generally have an audio receiver hooked into the Wheatstone bridge. This allows the operator to hear an audible AC tone until the bridge circuit is balanced and a null occurs. At the point of null, the resistance can be read from the pointer on the instrument adjustment dial.

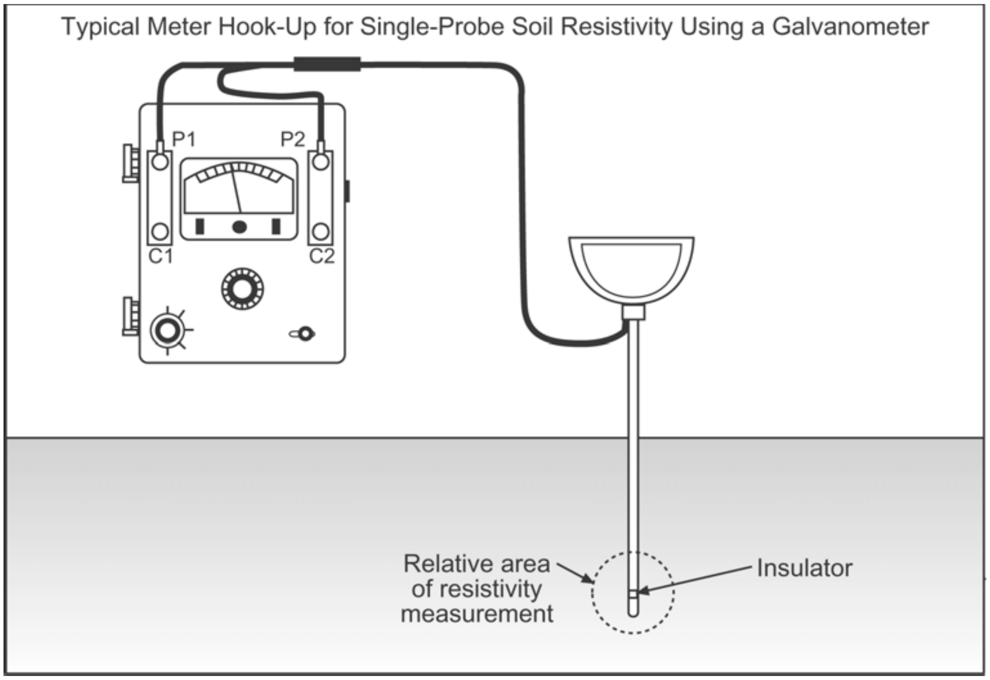

Figure A5: Single-Probe Method

A3.3.2 The resistivity measured by this method is only representative of the small volume of soil around the tip of the probe and should not be thought of as typical for all of the total soil area in question. Multiple measurements within the area of interest increase the validity of this method by increasing the sample size, if the point of interest can be reached with the probe. Single-probe measurements are generally used for comparative purposes or in excavations to locate anodes in the lowest-resistivity soil. This method is also useful when the close proximity of other underground metal structures makes the use of the four-pin method impractical.

A3.3.3 There are also several three-pin techniques for measuring soil resistivity. These are typically used for measuring resistivity at depths that are greater than those at which the four-pin method works. The four-pin method is limited in depth because of the ability of the meters to read a smaller and smaller resistance.

A4 Soil and Water Sample Collection and Analyses

The following procedures should be used for sample collection and analyses.

A4.1 Soil Samples

Soil samples should be collected with a clean spatula or trowel and placed in a 250 mL (8 fl. oz) plastic jar with a plastic lid. The sample jar should be packed full to displace air. Tightly close the jar, seal with plastic tape, and using a permanent marker, record the sample location on both the jar and the lid.

A4.2 Groundwater Samples

Water samples should always be collected from the open ditch when possible. Completely fill the plastic jar, seal, and identify the location as described in Paragraph A4.1.

A4.3 Sample Analyses

A4.3.1 Soil testing laboratories to perform the testing should be specifically equipped with wet laboratory facilities designed for soil testing.

A4.3.2 Samples should be tested for the following:

A4.3.2.1 Type Classification: Classify soil type by the Unified Soil Classification System (USCS),[13] United States Department of Agriculture standards, or other standards.

A4.3.2.2 Moisture Content: Determine the moisture content of the soil using a modified version of AASHTO Method T265.[14]

A4.3.2.3 Sulfide Ion Concentration in Water: See EPA Method 376.1.[15] Other commonly applied standard laboratory test methods are acceptable.

A4.3.2.4 Soil Conductivity: See ASTM G57. Other commonly applied standard laboratory test methods are acceptable.

A4.3.2.5 Soil pH: See ASTM G51.[16] Other commonly applied standard laboratory test methods are acceptable.

A4.3.2.6 Chloride Ion Concentration in Water: See ASTM D512.[17] Other commonly applied standard laboratory test methods are acceptable.

A4.3.2.7 Sulfate Ion Concentration in Water: See ASTM D516.[18] Other commonly applied standard laboratory test methods are acceptable.

A5 pH Testing

A5.1 If a liquid is present beneath the coating, take a sample using a syringe or cotton swab.

A5.2 Test the pH of the liquid using hydrion paper or its equivalent. Carefully slice the coating to a length to allow the test paper to be slipped behind the coating. Press the coating against the pH paper for a few seconds and then remove the pH paper. Note and record the color of the paper in relation to the chart provided with the paper.

A6 MIC Analyses

MIC analyses should be performed on corrosion products when MIC is suspected.[19]

Appendix B
Direct Examination—Coating Damage and Corrosion Depth Measurements
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

B1 Safety Considerations

Excavating and working around pressurized pipe involves potential risks. Appropriate safety precautions, such as those included in industry standards, government regulations, and company procedures, should be followed.

B2 Coating Type Identification

See Table 1 in NACE SP0169[20] for instructions on how to identify coating types.

B3 Coating Condition and Adhesion Assessment

B3.1 Coating inspection for holiday testing purposes should precede any other type of coating evaluation planned. Three situations could be encountered when the pipe surface at an excavation site is evaluated:

B3.1.1 The coating is in excellent condition and completely adhered to the pipe surface;

B3.1.2 The coating is partially disbonded or degraded; or

B3.1.3 The coating is completely missing; the pipe surface is bare.

B3.2 When the coating is in excellent condition, the likelihood of finding external corrosion is greatly reduced. When the coating is partially disbonded or degraded, the likelihood of finding external corrosion is increased. Therefore, the coating type and disbonded areas should be determined and documented.

B3.3 The following coating inspection procedures are commonly used:

B3.3.1 Collect selected coating samples to determine the properties of coating associated with corrosion. Subsequent analysis of the coating can provide information pertaining to electrical and physical properties (e.g., resistivity, gas permeability). The samples may also be used to perform microbial tests.

B3.3.2 Coating samples must be removed from the pipe surface. Any liquid under the coating should be sampled. The steel surface condition and liquid pH should be evaluated.

B3.3.3 Determine the pH of groundwater away from the pipe in the ditch, if possible, for reference. Compare this pH value with the pH determined from liquid removed under coating to determine whether the pH near the pipe is elevated. An elevated pH indicates the presence of CP current reaching the pipe. A water pH greater than approximately 9 would be considered elevated for most soils. It is not uncommon to determine a pH of 12 to 14 for well-protected steel.

B3.3.4 Visually inspect the steel surface for corrosion after the coating analysis is performed. Identify areas that may contain other types of anomalies such as SCC or where MIC may have contributed to external corrosion. This becomes essential when risk assessment results indicate the possibility of other threats that affect the pipeline or segment being evaluated.

B3.3.5 Measure the pipe surface temperature under the coating.

B4 Corrosion Product Removal

Carefully remove the coating around the suspected area of corrosion using a knife or similar instrument. Sample contamination must be kept to a minimum. Avoid touching the soil, corrosion product, or film with hands or tools other than a clean knife or spatula to be used in collecting the sample.

B5 Corrosion Product Analyses

B5.1 Corrosion product analyses may be useful in determining corrosion mechanisms or identifying unusual soil contaminants. Samples should be obtained from the following areas:

B5.1.1 A deposit associated with visual evidence of pipe corrosion;

B5.1.2 A scale or biofilm on the steel surface or the backside of the coating; and

B5.1.3 Liquid trapped behind the coating.

B5.2 The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the backside of the coating.

B6 Assessment of Corrosion Defects and Other Anomalies

B6.1 Identification and Mapping

At each excavation, an operator should measure and document the extent, morphology, and depths of any external corrosion to establish the overall pipeline integrity. During the direct examination process, certain anomalies may be identified and require further analysis to establish the overall integrity of the pipeline. The following paragraphs discuss some of the procedures used to assess such anomalies.

B6.2 Cleaning/Surface Preparation

B6.2.1 Accurate assessment of external corrosion anomalies can only be accomplished after thorough cleaning of the affected area. Following are guidelines for cleaning and preparation of the pipe surface before anomaly evaluation. The cleaning method chosen depends on the type of inspection technique and repair to be performed. For instance, if risk assessment results indicate that other anomalies, such as SCC, may be present, cleaning methods must be modified so that cleaning does not interfere with the detection of such anomalies.

B6.2.2 The objective of the pipe preparation process is to remove coating residue and corrosion deposits to optimize the effectiveness of the inspection. The steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products, and coating remnants.

B6.2.3 The pipeline operator should ensure that any cleaning material or technique selected meets the required occupational health and safety requirements.

B6.3 Anomaly Measurement and Evaluation Methods

B6.3.1 The exposed and cleaned pipe surface should be examined for external corrosion and other anomalies that may be present. Such examinations should be suitable for other anomaly types expected (in addition to external corrosion) and performed by a qualified person.

B6.3.2 The results of all pipe surface examinations should be thoroughly documented, including supplemental photographic records.

B6.3.3 The residual strength of the corroded pipe should be estimated using ASME B31G, RSTRENG, or equivalent assessment methods. Residual strength of anomalies other than corrosion should be assessed using other appropriate industry accepted methods.

B6.3.4 Corrosion depths may be determined using one or more of the following techniques. Additional nondestructive testing methods are typically required to determine the depths and extent of other anomaly types.

B6.3.4.1 Pit depth gauge.

B6.3.4.2 Ultrasonic thickness probe.

B6.3.4.3 Automated methods (e.g., laser mapping).

B6.3.4.4 Profile gauges.

B6.3.4.5 New Technology—Nonmanual and remote technologies continue to evolve and enable operators to better estimate wall loss and other damage. While each new technology is under evaluation, operators must demonstrate through the use of engineering reports that they are using a reliable procedure to detect and properly respond to that pipeline integrity threat.

B6.3.4.5.1 Accessible Pipe Exterior—At the time of this publication, this means field inspection applicatons for pipe that is accessible based on automatic eddy current, laser, and ultrasonic scanning techniques and methodologies. These continue to show improvement in reliability and usefulness.

B6.3.4.5.2 Inaccessible Pipe—At the time of this publication, this means field inspection applicatons for pipe that is inaccessible based on a variety of electromagnetic wave and guided wave techniques. These continue to show improvement in reliability and usefulness.

B6.3.5 Measurement of all external corrosion or other anomalies should be performed by a qualified person in accordance with the applicable assessment method.

Appendix C
Postassessment—Corrosion Rate Estimation
(Nonmandatory)

This appendix is considered nonmandatory, although it may contain mandatory language. It is intended only to provide supplementary information or guidance. The user of this standard is not required to follow, but may choose to follow, any or all of the provisions herein.

C1 Introduction

C1.1 External corrosion rates are an essential variable for establishing the interval between successive integrity evaluations and pipeline remediation needed to assure that integrity is maintained.

C1.2 When possible, external corrosion rates should be determined by directly comparing measured wall thickness changes that are detected after a known time interval. Such data may be from maintenance records, prior excavations (e.g., contained in pipeline inspection reports), or by other methods such as ILI.

C1.3 Other methods that may also be used for external corrosion rate estimates can include, but are not limited to, the following:

C1.3.1 Consideration of the external corrosion history on the pipe or segment being evaluated or in "like/similar" areas that contain the same pipe materials and similar environments. The data elements provided in Table 1 of this standard provide guidance for such evaluations.

C1.3.2 Consideration of the soil characteristics and environment surrounding the pipe or segment being evaluated to determine its corrosiveness. Such soil characteristics and environmental factors can include:

Chloride ion content	Microbiological activity
Moisture content	Redox potential
Oxygen content	Resistivity
Permeability	Soil texture
pH	Drainage characteristics
Stray currents	Sulfate, sulfite ion concentrations
Temperature	Total hardness
Total acidity	Soil composition changes that may create long-line current

C1.3.2.1 Other soil or environmental changes that can affect external corrosion rates include spillage of corrosive substances, pollution, and seasonal soil moisture content variations.

C1.3.3 Under some conditions, external corrosion rates may also be determined using buried coupons, linear polarization rate measurements, or electrical resistance probes.

C1.3.4 Actual corrosion rates are difficult to predict and measure. Corrosion estimation techniques may not simulate actual field conditions. Caution should be exercised when computing corrosion rates.

C2 Corrosion Rate Estimates

C2.1 Additional guidance for establishing estimated external corrosion rates is provided below.

C2.2 Estimating Corrosion Initiation Time

C2.2.1 Assuming that external corrosion initiated at the time a pipeline went into service may result in nonconservative rate estimates. A coating system may delay the onset of corrosion for a significant time period.

C2.2.2 Corrosion initiation time estimates can be made by considering the following.

C2.2.2.1 Historical records evaluated during overall pipeline risk (threat) and the *Preassessment Step.*

C2.2.2.2 Evidence that the corrosion is associated with coating damage that most likely occurred during original construction or other maintenance action. For example, coating damage associated with rock or debris in the backfill is likely to have occurred during construction.

C2.2.2.3 Evidence that the corrosion is associated with coating damage resulting from third-party activity that occurred at a known time. For example, external corrosion accompanied by mechanical damage to the pipe or coating on the top half of the pipe in an area where third-party activity is known to have occurred most likely initiated and grew since the time of the third-party activity.

C2.2.2.4 Estimated time period that the coating provided an efficient barrier between the pipe and external environment and records that may indicate initial coating quality. Whenever available, the operator should use pipeline inspection records in an attempt to determine when the coating no longer provided effective protection. Published corrosion rate data describing long-term corrosion tests performed on pipe coated with various materials indicate that coating degradation rates can be significantly influenced by soil type, original coating quality, and pipeline installation practices.[21]

C2.2.2.5 Time periods when CP systems were out of service, not functioning normally, or protective potentials were not maintained for significant time periods. Also, any significant time period between pipe construction and installation of an effective CP system should be considered when corrosion rates are estimated.

C2.3 Other Factors

C2.3.1 Other factors that may affect external corrosion rate estimates are as follows:

C2.3.1.1 Exposure time: Corrosion rates often, but not always, decrease with longer exposure times. For example, data from tests of bare pipe in soils indicate that corrosion rates from 0 to ~7 years of exposure are typically higher than for longer exposure periods.

C2.3.1.2 Surface area exposed: Testing has demonstrated that the probability of finding a larger pit increases when a test sample with a larger surface area is inspected. The larger the total area of coating damage, the greater the probability that the actual maximum corrosion rate will be higher than the rates described above. This influence may be particularly important for predicting the maximum penetration rate of bare pipelines.

C2.3.1.3 Coating: Coatings are designed to delay the onset of corrosion by providing an effective barrier between the pipe and soil. However, pitting rates in the area of localized coating defects may exceed the pitting rates of bare steel exposed to the same environment. The effect of the coating on the rate of pitting is dependent on the coating type and the soil characteristics.

C2.3.1.4 Seasonal variability on soil characteristics: Few published corrosion data include descriptions of the extent of seasonal variability on soil characteristics.[21] Soil characteristics measured at one point in time may not be representative of soil corrosiveness at other times of the year. Soils that undergo cyclic wetting and drying can be more corrosive than soils that are constantly wet. The cyclic changes in moisture can cause soil stress that damages coatings and can also result in cyclic diffusion of oxygen into the soil.

C2.3.1.5 Long-line current: Pipelines passing through different soils can be influenced by long-line current that is not apparent in localized corrosion tests. Long-line current can result in higher corrosion rates on one segment of a pipeline, compared to corrosion rates measured on isolated samples buried in the same soil.

C2.3.1.6 Microbiological activity can accelerate external corrosion rates and must be considered in evaluations.

C3 Default Corrosion Rate

C3.1 Statistically valid methods based on the data developed may be used for corrosion rate estimates.

C3.2 When other data are not available, a pitting rate of 0.4 mm/y (16 mpy) should be used for determining reinspection intervals. This rate represents the upper 80% confidence level of maximum pitting rates for long-term (up to 17 year duration) underground corrosion tests of bare steel pipe coupons without CP in a variety of soils, including native and nonnative backfill. See Paragraph 6.6.1.

C3.3 The corrosion rate in Paragraph C3.2 may be reduced by a maximum of 24%, provided it can be demonstrated that the CP level of all pipelines or segments being evaluated have had at least 40 mV of polarization (considering IR drop) for a significant fraction of the time since installation.

C3.4 Linear Polarization Resistance Measurements

C3.4.1 Linear polarization resistance (LPR) measurements are performed to evaluate the ongoing, instantaneous rate of corrosion in the laboratory and in the field.

C3.4.2 LPR measurements in the laboratory are often performed as described in ASTM G59,[22]

C3.4.2.1 The coupon potential is scanned between –30 mV and +30 mV of the free corrosion potential at a scan rate of 0.17 mV/s. The ensuing current is monitored as a function of potential. The tangent to the potential-current plot at the free corrosion potential is the polarization resistance (LPR value). Use of scans within smaller potential ranges (e.g., –10 mV to +10 mV of the free corrosion potential) are also acceptable.

C3.4.2.2 These LPR values are then converted to corrosion currents using Equation (C1), the Stern-Geary[23] equation:

$$i_{corr} = \frac{\beta}{PR} \quad \text{(C1)}$$

where:

i_{corr} is the corrosion current density in A/cm^2;
β is the Stern-Geary constant; and
PR is the polarization resistance in Ω.

C3.4.2.3 The Stern-Geary constant is dependent on the anodic and cathodic Tafel constants. Corrosion current density values are then converted to corrosion rates using Faraday's Law.

C3.4.2.4 Tafel slopes must be known to use this technique.

C3.4.3 Two commercially available LPR probe systems are commonly used for LPR measurements to provide online corrosion rate monitoring in the laboratory and in the field. Mass loss data are used as the basis for calibration of both of these LPR probe systems. The systems are capable of producing a pitting index, which is an indication of the tendency of the fluid to cause pitting of the electrodes. The two systems differ by the number of electrodes that are used.

C3.4.3.1 The two-electrode system uses two electrodes of the same material. The potential between the two electrodes is set to 20 mV, and the current is measured. The potential drop is assumed to divide equally between the anode and the cathode. The current flowing is proportional to the corrosion rate. The corrosion rate can be calculated using ASTM G102.[24]

C3.4.3.2 The three-electrode system is composed of a working, reference, and counter electrode. The electrodes are typically made of the same material. As the potential of the working electrode with respect to the reference electrode is monitored, current is applied to or from the counter electrode such that the potential of the working electrode shifts by 10 mV (positive or negative). At that point, the current flowing is proportional to the corrosion rate.

C3.4.4 The LPR method is the only corrosion monitoring method that allows real-time measurement of corrosion rates. This enables remedial action shortly after an acceleration in the corrosion rate is observed. This is the chief advantage of LPR probes. Because the corrosion rates determined by LPR probes reflect conditions at the time of measurement, they may not necessarily correspond with the corrosion rates determined using coupons. Corrosion rates determined using coupons represent an average mass loss that accounts for corrosion that has occurred throughout the coupon's exposure period. Because the operation of the LPR probe depends on electrical current, the accumulation of deposits on the electrodes can influence the pitting index reported by the probes.

C3.5 Determining Corrosion Rates Using Coupon Monitoring of Cathodically Protected Pipe

C3.5.1 The purpose of coupon methodology is to provide a means of determining the corrosion rates of steel with or without the influence of CP. Corrosion coupons provide the ability to measure corrosion rates without excavating a pipeline, and they can be used to determine the type of corrosion as well as the corrosion rate.

C3.5.2 Effective testing requires that coupons be located in soil having characteristics representative of the environment in which the pipe is located. Therefore, efforts should be made to locate the coupons close to the pipe surface and to ensure that coupon exposure to air and moisture are comparable to conditions at the pipe surface.

C3.5.3 One design of corrosion coupon assemblies currently used for monitoring CP effectiveness involves burial of two bare coupons in a test station near the pipe surface. One coupon is connected to the pipeline (polarized coupon) and one coupon remains unconnected and allowed to corrode freely (native coupon). In this manner, it is expected that the polarized coupon will be polarized to a similar potential as a pipe surface holiday of similar area. The native coupon provides a "worst-case" illustration of the type and extent of corrosion that can occur if CP does not reach portions of the pipe.

C3.5.4 The polarized potential of a coupon does not mirror the pipe polarized potential. There are several variables that combine to establish the pipeline polarized potential including coating quality, holiday size, and holiday configuration. The polarized potential of the coupon theoretically simulates the polarization of a holiday of similar size on the pipe. Therefore, the coupon does not estimate the pipe polarized potential but provides an evaluation of CP system effectiveness by accurately estimating the potential of a coupon connected to the CP system.

C3.5.5 Evaluation consists of coupon retrieval, cleaning, and corrosion measurements. Guidance regarding coupon cleaning, corrosion rate calculations, and data reporting can be found in NACE Standard TM0169.[25]

ISBN 1-57590-156-0
NACE International