# Recommended Practice for Assessment and Management of Cracking in Pipelines

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## Introduction

This recommended practice (RP) provides guidance to the pipeline industry for assessment and management of defects in the form of cracking, with particular emphasis on contributing threats and the applicable assessments. The RP presents detailed guidance for developing a crack management program. The crack management RP includes the following:

— selecting suitable methods for assessing the condition of the pipeline with respect to applicable forms of cracking;

— establishing response criteria for in-line inspection (ILI) results and determining a pressure reduction where the excavation is delayed beyond the intended timeline;

— determining appropriate hydrostatic test levels and duration;

— calculating the remaining lives of anomalies that may remain in the system so that reassessment can be carried out to reevaluate the anomalies and remediate if necessary;

— developing preventive and mitigative measures for cracking-related conditions in lieu of or in addition to periodic integrity assessment.

This RP is intended for use by operators in planning, implementing, and improving a pipeline crack management program.

Although the genesis and structure of this RP is the API 1160 RP for liquid hazardous pipeline managed under U.S. Department of Transportation (DOT) 49 *Code of Federal Regulations* (*CFR*) 195.452 of the U.S. federal pipeline safety regulations, this RP is written as a broadly applicable framework for both hazardous liquid and gas pipelines located in any location or under any jurisdiction. This RP augments API 1160 in aiding the development of integrity management programs that are required under U.S. federal pipeline safety regulations.

Recommended Practice for Assessment and Management of Cracking in Pipelines

# 1 Scope

This recommended practice (RP) is applicable to any pipeline system used to transport hazardous liquid or natural gas, including those defined in U.S. Title 49 *Code of Federal Regulations (CFR)* Parts 192 and 195.

This RP is specifically designed to provide the operator with a description of industry-proven practices in the integrity management of cracks and threats that give rise to cracking mechanisms. The guidance is largely targeted to the line pipe along the right-of-way (ROW), but some of the processes and approaches can be applied to pipeline facilities, including pipeline stations, terminals, and delivery facilities associated with pipeline systems. Defects associated with lap-welded (LW) pipe and selective seam weld corrosion (SSWC) are not covered within this RP.

This RP presents the pipeline industry's understanding of pipeline cracking. Mechanisms that cause cracking are discussed, methods to estimate the failure pressure of cracks are reviewed, and methods to estimate crack growth are presented. Selection of the appropriate integrity assessment method for various types of cracking, operating conditions, and pipeline characteristics is discussed. This RP also reviews current knowledge about in-line inspection (ILI) technology and in-the-ditch (ITD) nondestructive evaluation technology. A methodology for responding to ILI indications and specific criteria for when to respond to certain results is presented. Applicable repair techniques are reviewed. Sections are included for the discussion of reassessment interval determination and the consideration of appropriate preventive and mitigative measures. Finally, some meaningful performance metrics for measuring the effectiveness of a crack management program are discussed.

The technical discussion about crack formation, growth, and failure is to provide the knowledge needed by operators to effectively make integrity decisions about managing cracking on their pipeline systems.



# 2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API 579-1/ASME FFS-1 [1], *Fitness-For-Service*, June 2007

API Recommended Practice 1110, *Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide*

API Recommended Practice 1160, *Managing System Integrity for Hazardous Liquid Pipelines*, Second Edition

ASME B31.4-2012, *Pipeline Transportation Systems for Liquids and Slurries*

ASME B31.8-2012, *Gas Transmission and Distribution Piping Systems*

ASME B31G-2012, *Manual for Determining the Remaining Strength of Corroded Pipelines*

BS 7910-2013 [2], *Guide to Methods for Assessing the Acceptability of Flaws in Metallic Structures*

NACE SP0204 [3], *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*, 2008

[1] ASME International, 2 Park Avenue, New York, New York 10016-5990, www.asme.org.
[2] British Standards Institution, Chiswick High Road, London, W4 4AL, United Kingdom, www.bsi-global.com.
[3] NACE International (formerly the National Association of Corrosion Engineers), 15835 Park Ten Place Houston, Texas 77084, www.nace.org.

# 3 Terms, Definitions, Acronyms, and Abbreviations

## 3.1 Terms and Definitions

For the purposes of this document the following terms and definitions apply.

**3.1.1**
**anomaly**
Possible, unexplained deviation from the norm in sound pipe material, coatings, or welds.

NOTE 1 See also **flaw**, **defect**, and **imperfection**.

NOTE 2 Indication can be generated by nondestructive inspection; see NACE 35100.

**3.1.2**
**assessment**
Evaluation or estimation of the nature, quality, or ability of a person or object.

NOTE The term integrity assessment is used to determine the pipe's current condition.

**3.1.3**
**autogenous weld**
Weld produced without filler metal.

**3.1.4**
**brittle fracture**
Fracture with little or no plastic deformation.



**3.1.5**
**certainty**
Probability that a reported anomaly characteristic is within a stated tolerance.

NOTE This can also be referred to as a proportion or coverage probability.

**3.1.6**
**cold weld (lack-of-fusion)**
Lack of adequate weld bonding strength of the abutting edges due to insufficient heat and/or pressure and that possibly has separation in the electric resistance welding (ERW) or electric flash-welded (EFW) weld line.

NOTE This is not a metallurgically exact term, but rather a general indication of the condition.

**3.1.7**
**cold work**
Permanent strain in a metal accompanied by strain hardening.

**3.1.8**
**competent**
Qualified, trained, and experienced to perform the required duties.

**3.1.9**
**consequence**
Impact that a pipeline failure could have on the public, employees, property, or the environment.

**3.1.10**
**crack**
Very narrow, elongated defect caused by mechanical splitting into two parts.

**3.1.11**
**critical location**
Locations such as populated areas, commercially navigable waterways, drinking water resources, or ecologically sensitive areas that are deemed by the operator or otherwise defined by regulations to be areas of elevated consequences.

**3.1.12**
**defect**
Imperfection of a type or magnitude exceeding acceptable criteria.

NOTE See also **anomaly** and **imperfection**.

**3.1.13**
**dent**
**indentation**
Local change in pipe surface contour that is caused by an external force such as mechanical impact or rock impingement but is not accompanied by loss of metal.

**3.1.14**
**design pressure**
Pressure defined by the yield strength, wall thickness, nominal outside diameter, and appropriate joint and design factors.



**3.1.15**
**direct assessment**
**DA**
Integrity assessment processes for detecting time-dependent degradation of a pipeline caused by external corrosion, internal corrosion, or stress corrosion cracking (SCC) that involve making certain measurements, conducting certain analyses, and excavating the pipeline where appropriate to examine its condition.

**3.1.16**
**direct current voltage gradient**
**DCVG**
Inspection technique that includes aboveground electrical measurements taken at predetermined increments along the pipeline and is used to provide information on the effectiveness of the coating system.

**3.1.17**
**disbondment**
**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.

NOTE Disbonded coating need not be associated with a coating holiday.

**3.1.18**
**eddy current**
Inspection method that uses electromagnetic induction to detect discontinuities in conductive materials.

**3.1.19**
**electromagnetic acoustic transducer**
**EMAT**
Type of transducer that generates ultrasound in steel pipe without a liquid couplant using magnets and coils for inspection of the pipe.

**3.1.20**
**engineering critical assessment**
**ECA**
Analytical procedure, based upon fracture mechanics, that allows determination of the maximum tolerable sizes for imperfections and is conducted by, or under the supervision of, a competent person with demonstrated understanding and experience in the application of the engineering principles related to the issue being assessed.

NOTE Used synonymously with the term Fitness-For-Service (FFS) and engineering assessment in different jurisdictions.

**3.1.21**
**environmentally assisted cracking**
**EAC**
Corrosive attack of the pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking.

EXAMPLE EAC includes but is not limited to hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide stress cracking (SSC), or stress corrosion cracking (SCC).

**3.1.22**
**estimated rupture pressure**
**ERP**
Failure pressure, estimated using an appropriate FFS calculation without a factor of safety.



**3.1.23**
**evaluation**
Review, following the characterization and possible examination of an anomaly, to determine whether the anomaly meets specified acceptance criteria.

**3.1.24**
**failure**
General term used to imply that a part has become functionally inoperable due to a leak or rupture from a crack.

**3.1.25**
**failure pressure ratio**
**FPR**
Ratio of the ERP to the maximum pressure expected during service, i.e. the ratio of the calculated failure pressure of an anomaly to the maximum normal operating pressure at the location of the anomaly, i.e. FPR = ERP/MOP.

**3.1.26**
**fatigue**
Process of forming or enlarging a crack as a result of repeated cycles of stress.

**3.1.27**
**fault**
Any anomaly in the coating, including disbonded areas and holidays.

**3.1.28**
**flaw**
Imperfection that is smaller than the maximum allowable size.

**3.1.29**
**fracture toughness**
Resistance of a material to fail from the extension of a crack.

**3.1.30**
**fusion-bonded epoxy coating**
**FBE coating**
Polymer coating that is chemically cured in place by heating.

**3.1.31**
**gouge**
Elongated grooves or cavities usually caused by mechanical removal or smearing of metal.

**3.1.32**
**grinding**
Removal of material at the pipe surface in a controlled process in order to facilitate nondestructive examination (NDE), explore the depth of a surface feature, or remove a surface feature leaving a smooth contour; sometimes also called "sanding" or "buffing."

**3.1.33**
**hard spot**
Area in the pipe with a hardness level considerably higher than that of the surrounding metal, usually due to localized quenching or alloy segregation.



**3.1.34**
**hook crack**
Metal separations in ERW or FW pipe, resulting from imperfections at the edge of the plate or skelp, parallel to the surface, which turn toward the inner diameter (ID) or outer diameter (OD) pipe surface when edges are upset during welding.

**3.1.35**
**hydrostatic test**
Means of assessing the integrity of a new or existing pipeline, as detailed in API 1110, that involves filling the pipeline with water and pressurizing to a level significantly in excess of the pipeline MOP/MAOP for an appropriate duration to confirm no leaks are present and to demonstrate that the pipeline is fit for service at the MOP/MAOP.

**3.1.36**
**imperfection**
Flaw or other discontinuity noted during inspection that passes acceptance criteria during an engineering and inspection analysis.

NOTE See also **anomaly** and **defect**.

**3.1.37**
**incident**
Unintentional release due to the failure of a pipeline.

**3.1.38**
**inclusion**
Nonmetallic phase in a metal pipeline such as oxides, sulfides, or silicate particles.

**3.1.39**
**indication**
Finding from nondestructive testing (NDT), inspection technique, or a signal from an ILI system.

**3.1.40**
**in-line inspection**
**ILI**
Inspection of a pipeline from the interior of the pipe using an inspection tool.

NOTE 1 This is also called intelligent or smart pigging.

NOTE 2 This includes tethered and self-propelled inspection tools.

**3.1.41**
**in-line inspection tool**
**ILI tool**
Instrumented device or vehicle that uses a NDT technique to inspect the pipeline from the inside to detect features along a pipeline.

**3.1.42**
**inspection**
Use of a NDT technique.

**3.1.43**
**integrity**
Capability of the pipeline to safely withstand all anticipated loads.



**3.1.44**
**internal corrosion direct assessment**
**ICDA**
Integrity assessment process conducted for the purpose of locating and remediating anomalies arising from internal corrosion of a pipeline.

NOTE See NACE SP0206 (DG-ICDA standard for dry gas), NACE SP0110 (WG-ICDA standard for wet gas), and NACE SP0208 (LP-ICDA standard for liquid petroleum).

**3.1.45**
**lamination**
Planar discontinuity, usually oriented parallel or near parallel to the pipe surface, that is the result of inconsistencies in the material used in the pipe manufacturing process.

**3.1.46**
**leak**
Failure of the pipe without unstable extension or propagation of a fracture and that allows a release of pipe contents, usually without a loss of system pressure while in operation.

**3.1.47**
**magnetic flux leakage**
**MFL**
Type of ILI technology in which a magnetic field is induced in the pipe wall between two poles of a magnet to detect, classify, and characterize anomalies.

**3.1.48**
**mapping tool**
ILI tool that uses inertial sensing or other technology to collect data that can be analyzed to produce an elevation and plan view of the pipeline route.

**3.1.49**
**maximum allowable operating pressure**
**MAOP**
Maximum pressure at which a gas pipeline system may be operated in accordance with the provisions of the applicable code.

**3.1.50**
**maximum operating pressure**
**MOP**
Maximum pressure at which a liquid pipeline system may be operated in accordance with the provisions of the applicable code.

**3.1.51**
**mechanical damage**
Generic term used to describe combinations of dents, gouges, and/or cold work caused by the application of external forces and can also include coating damage, movement of metal, and high residual stresses.

**3.1.52**
**microbiologically influenced corrosion**
**microbe-induced corrosion**
**MIC**
Corrosion or deterioration of metals resulting from the metabolic activity of microorganisms.



**3.1.53**
**mitigation or mitigative action**
Taking appropriate action based on an assessment of risk factors to reduce the overall level of pipeline integrity risk by reducing the amount of risk from a probability or consequence standpoint.

**3.1.54**
**operating stress**
Stress in a pipe or structural member under normal operating conditions.

**3.1.55**
**operator**
Entity that operates pipeline facilities.

**3.1.56**
**penetrator**
Localized spot of incomplete fusion in an ERW or EFW seam.

**3.1.57**
**pipeline system**
All portions of the physical facilities through which liquid or gas moves during transportation

NOTE This includes pipe, valves, and other appurtenances attached to the pipe, compressor units, pumping units, metering stations, regulator stations, delivery stations, breakout tanks, holders, and other fabricated assemblies.

**3.1.58**
**pipe-to-soil potential**
Electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

**3.1.59**
**pitting**
Localized corrosion of a metal surface that is confined to small areas and takes the form of cavities called pits.

NOTE See API 1163.

**3.1.60**
**plastic collapse**
**ductile fracture**
Failure that occurs by ductile fracture and is governed by material strength properties.

**3.1.61**
**preventive and mitigative measures**
Activities designed to reduce the likelihood of a pipeline failure (preventive) and/or minimize or eliminate the consequences of a pipeline failure (mitigative).

**3.1.62**
**probability of detection**
**POD**
Probability of a feature being detected by an ILI tool.



**3.1.63**
**probability of identification**
**POI**
Probability that the type of an anomaly or other feature, once detected, will be correctly classified (e.g. as metal loss, dent, etc.).

**3.1.64**
**remaining life**
Estimate of the time to failure of an assumed or indicated flaw based on a crack growth analysis.

NOTE Where remaining life is used in this document, it is always implied that it is an estimation.

**3.1.65**
**remediation or remedial action**
Taking appropriate action to remove one or more causes of pipeline risk or of an injurious anomaly.

EXAMPLE Action can consist of, but is not limited to, repair of defects, further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, and administrative/procedural changes.

**3.1.66**
**residual stress**
Stress present in an object in the absence of any external loading, typically resulting from manufacturing or construction processes.

**3.1.67**
**risk**
Measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

**3.1.68**
**risk assessment**
Systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined.

**3.1.69**
**rupture**
Failure of the pipe in a manner that involves unstable extension or propagation of a fracture, resulting in a release of pipe contents and usually an inability to maintain pressure while in operation.

**3.1.70**
**shielding**
Preventing or diverting the flow of cathodic protection (CP) current from its natural path.

**3.1.71**
**sizing accuracy**
Accuracy with which an anomaly dimension or characteristic is reported.

**3.1.72**
**spike test**
Short-duration hydrostatic test wherein the pressure level is higher than the strength test, the purpose of which is to achieve an increased level of confidence in the serviceability of the pipeline or an increased interval until the next assessment.

**3.1.73**
**strain**
Change in length of a material in response to an applied force, expressed on a unit length basis.



EXAMPLE Inches per inch or millimeters per millimeter.

**3.1.74**
**strength test**
Method of proving the ability of a piece of pipe or equipment to safely operate at its intended pressure by subjecting it to an elevated pressure in accordance with applicable standards or regulations.

**3.1.75**
**stress**
Tensile, shear, or compressive force per unit area.

**3.1.76**
**stress corrosion cracking**
**SCC**
Form of cracking produced by the combined application of tensile stress (residual or applied), a corrosive environment, and steel that is susceptible to SCC.

**3.1.77**
**stress corrosion cracking direct assessment**
**SCCDA**
Direct assessment conducted for the purpose of locating and remediating anomalies arising from SCC of a pipeline or evaluating whether SCC is a threat on a particular pipeline.

NOTE See NACE SP0204.

**3.1.78**
**stress level**
Level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength (SMYS).

**3.1.79**
**transit fatigue**
Development of longitudinal fatigue cracks in line pipe as the result of transportation by rail car, truck, or marine vessel.

**3.1.80**
**validation**
Check of the accuracy of ILI results against empirical evidence, observations, or field measurements.

**3.1.81**
**verification**
Check of the effectiveness of any inspection method performance, including an ILI tool processes.

## 3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

| | |
|---|---|
| CCW | counterclockwise |
| *CFR* | *Code of Federal Regulations* |
| CMFL | circumferential magnetic flux leakage |
| $CO_2$ | carbon dioxide |
| CP | cathodic protection |
| CT | compact tension |
| CTOD | crack tip opening displacement |
| CVN | Charpy V-notch |
| CW | clockwise |
| DA | direct assessment |
| DC | direct current |
| DC-ERW | direct current electric resistance welding |
| DCVG | direct current voltage gradient |
| DSAW | double submerged arc welding |
| DWT | drop weight tear |
| EAC | environmentally assisted cracking |
| ECA | engineering critical assessment |
| EDM | electrical discharge machining |
| EFW | electric flash-welded |
| EMAT | electromagnetic acoustic transducer |
| ERP | estimated rupture pressure |
| ERW | electric resistance welding |
| FAD | failure assessment diagram |
| FBE | fusion-bonded epoxy |
| FFI | full field inversion |

| | |
|---|---|
| FFS | Fitness-For-Service |
| FGE | fuel grade ethanol |
| FITT | fracture initiation transition temperature |
| FPR | failure pressure ratio |
| FPTT | fracture propagation transition temperature |
| $H_2S$ | hydrogen sulfide |
| HAZ | heat-affected zone |
| HF | high-frequency |
| HF-ERW | high-frequency electric resistance welding |
| HIC | hydrogen-induced cracking |
| HSLA | high-strength low-alloy |
| ICDA | internal corrosion direct assessment |
| ID | inner diameter |
| ILI | in-line inspection |
| IMP | integrity management plan |
| ITD | in-the-ditch |
| JIP | Joint Industry Project |
| LF | low-frequency |
| LF-ERW | low-frequency electric resistance welding |
| LW | lap-welded |
| LWUT | liquid wheel ultrasonic |
| MAOP | maximum allowable operating pressure |
| MFL | magnetic flux leakage |
| MIC | microbiologically influenced corrosion |
| MOP | maximum operating pressure |
| MPI | magnetic particle inspection |
| MT | magnetic particle testing |
| MTR | mill test report |
| NDE | nondestructive examination |
| NDT | nondestructive testing |
| NPS | nominal pipe size |
| OD | outer diameter |
| PE | polyethylene |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| POD | probability of detection |
| POI | probability of identification |
| PRCI | Pipeline Research Council International |
| PWHT | postweld heat treatment |
| ROW | right-of-way |
| SA | shear appearance |

| | |
|---|---|
| SATT | shear appearance transition temperature |
| SAW | submerged arc welded |
| SCC | stress corrosion cracking |
| SCCDA | stress corrosion cracking direct assessment |
| SMYS | specified minimum yield strength |
| SOHIC | stress-oriented hydrogen-induced cracking |
| SSAW | single submerged arc welded |
| SSC | sulfide stress cracking |
| SSWC | selective seam weld corrosion |
| TOFD | time-of-flight diffraction |
| TS | tensile strength |
| UT | ultrasonic testing |
| YS | yield stress |

# 4 Guiding Principles

The development of this RP was based on certain guiding principles. These principles are reflected in many of the sections and are provided here to give the reader the sense of the need to view management of cracking in pipelines from a broad perspective. The overall guiding principle of this document is to identify elements of crack management for incorporation into an integrity management plan (IMP).



Effective integrity management of cracks relies on qualified people using defined and appropriate processes to operate well maintained and reliable facilities. The integrity of the physical facility is only part of the complete system that allows an operator to reduce both the number of incidents and the adverse effects of errors and incidents. The total system also includes the people that operate the facility and the work processes that the employees use and follow. Comprehensive crack management addresses the interaction of people, processes, and facilities.

Crack management is just one element of an integrity management program. This document serves to identify the necessary data for crack management that should be integrated into an operator’s integrity management program. The program elements should be flexible such that it can be customized to support each operator’s unique conditions. Furthermore, the program elements should be continually evaluated and modified to accommodate changes in the pipeline design and operation, changes to the environment in which the system operates, new operating data, or other integrity-related information. Periodic evaluation is required to be sure the operator takes appropriate advantage of improved or new technology, that crack management remains integrated with the operator’s IMP, and that it effectively supports the operator's integrity goals.

The integration of information is a key component for managing threats to integrity posed by cracks. A key element of crack management is the integration of all relevant information in the decision-making process. Information that can impact an operator's understanding of the important risks to a pipeline system comes from a variety of sources. By integrating all of the relevant information, the operator can determine where the risks of an incident are relevant, identify the greatest threats, and make prudent decisions to reduce these risks. The scope of the document is intended to provide guidelines on data integration by identifying the necessary data for review in Sections 6 through 17. These sections should be reviewed periodically to determine if any changes need to be implemented. An operator should have procedures in place within their IMP to implement necessary changes across their organization.

Operators shall take action to address crack-related integrity issues raised from assessments and information analysis. Operators shall evaluate anomalies and identify those that are potentially injurious to pipeline integrity and take appropriate action to remediate or eliminate injurious defects.

When managing cracks, a lack of adequate data for making critical integrity decisions can make the use of assumptions necessary. When this is the case, the assumptions should be conservative, but realistic and supportable, by institutional knowledge of the system, industry knowledge, or other information. Excessive conservatism based on unrealistic assumptions can make operators unable to distinguish real versus artificial risk levels.

# 5 Crack Management

## 5.1 General Considerations

Pipeline crack management should facilitate appropriate and timely actions on the part of a pipeline operator to ensure that a pipeline system is continually operated in a manner that reduces risk to any stakeholder, including the public/employees, the environment, and the customers. This document provides a guideline for pipeline operators to use in developing crack management plans within the context of a more general integrity management program.

In simplest terms crack management should:

— identify the extent to which cracking could affect pipeline integrity;

— provide for timely assessment of the integrity of each segment with respect to the possibility of cracking on a prioritized basis that is informed by an assessment of risk;

— establish reassessment frequencies, as applicable;

— define preventive and mitigative measures to address relevant threats, including those not covered by integrity assessments.



One way of implementing crack management is to do so in terms of the life cycle of a pipeline. Cracking and cracking conditions can exist from the original manufacture or construction quality or practices. The data available should be reviewed to determine the types or extent of possible cracking. the data review may include the following:

— details of manufacturing and construction practices,

— as-built records [e.g. mill test report (MTR) historical rejects; X-ray results],

— pre-commissioning ILI data,

— pre-commissioning ITD data,

— commissioning hydrostatic pressure tests,

— metallurgical analyses of failed or sampled pipe and components.

Once the pipeline enters service, cracking can be associated with operating conditions that vary depending on how the pipe is used, corrosive conditions, external mechanical damage, and stress. Normal operation can result in aggravation of some of the conditions listed above or development of cracking separate from initial quality factors. Operational conditions to consider may include some of the following (not all inclusive):

— CP systems (CP potential, close interval surveys, interference),

— coating deterioration,

— land movement,

— heat and pressure cycles.

Data that may be reviewed include:

— ILI data,

— ITD data,

— hydrostatic pressure tests,

— metallurgical analyses of failed or sampled pipe and components.

Long-term management of cracking over the full life cycle requires ongoing inspection and maintenance practices that are used to monitor the conditions. Some of the tools and processes for long-term cracking management are the same tools and processes that can be used to determine cracking related to the initial condition of the pipeline.

## 5.2 Elements of Crack Management to Incorporate into Integrity Management Plans

*Data Gathering, Review, and Integration*—To understand the potential threats to the integrity of a pipeline segment posed by the presence of cracks or cracking mechanisms, an operator shall gather, review, and integrate available relevant information. Such information generally consists, but is not limited to, the following:

— the design of the pipeline;

— the attributes of the pipeline such as diameter, wall thickness, grade, vintage, and manufacturing process;

— operational history including operating pressure and temperature ranges and any past releases;



— results of prior inspections and assessments including any ILIs, DAs, or hydrostatic tests;

— previously made repairs, including repair criteria and procedures, or other mitigative responses;

— corrosion, coating, and CP surveys;

— metallurgical data, where available;

— environmental conditions including soils data;

— measures taken to prevent releases or the effects of a release due to cracks;

— perform review of significant incidents.

An operator shall also consider gathering, reviewing, and integrating the operator's own incidents and near misses, as well as industry incidents and trends, regulatory notices, and other operators' experiences where applicable.

The pipeline industry has modeled threats to varying levels of detail, examples of which are provided in ASME B31.8S and API 1160. Although pipeline integrity management entails addressing each of these threats, only a portion of them are related to cracking. Pressure-cycle-induced fatigue crack growth is a much greater threat for liquid pipelines than it is for gas pipelines; therefore, the threat of any one of several types of defects becoming enlarged by pressure-cycle-induced fatigue becomes an additional threat category for liquid operators to consider. Consequently, threats that ASME B31.8S designates as “stable” are viewed in this RP as time-dependent. In API 1160, this is addressed as a separate threat where an initially non-injurious condition arising from any cause grows into an injurious defect via pressure-cycle-induced fatigue.

The threats for cracking that operators should address within a crack management program can be characterized as follows, with pressure-cycle-induced fatigue incorporated as a consideration in each as applicable:

— environmentally assisted cracking (EAC), including SCC and corrosion fatigue,

— certain manufacturing defects associated with the pipe body or seam,

— mechanical damage,

— certain construction and fabrication defects.

*Incorporation of Crack Management Elements*—For each pipeline segment where the threat of cracking has been identified, each element of a pipeline operator's IMP should contain provisions for managing crack threats. The pipeline operator's plan should identify the ILI technique(s), pressure testing, or other technology that is to be used to assess the integrity of the pipeline as possibly affected by cracks. It should also establish the schedule for conducting these assessments, the justification for the integrity assessment method(s) selected, and mitigative measures that is to be employed.

*Inspection, Mitigation, and/or Remediation*—The pipeline operator should implement the crack management practices, evaluate the results, and make any necessary repairs in a timely manner to assure that anomalies associated with cracking that pose an integrity threat are eliminated or remediated. For pipeline segments that could affect critical locations, the operator should establish reasonable and technically justifiable time limits for the response to anomalies detected by ILI that could affect integrity. This schedule should also consider applicable regulatory statutes. Section 11 provides guidance for prioritizing features identified by ILI for examination and repair.



*Continue to Assess for Cracks Periodically*—Pipeline operators should analyze the results of inspections and repairs, as well as other factors, to establish schedules for performing assessments on a periodic basis. Periodic assessments should use one or more assessment techniques suitable to detect the presence and severity of cracking that could affect the pipeline. The pipeline operator should develop a schedule for reassessments that considers items such as the rates of deterioration, the consequences of an event, and other factors that could affect risk. Section 8 provides guidelines for scheduling reassessments.

*Establish and Implement Preventive and Mitigative Measures*—A pipeline operator should establish and implement a process to evaluate the need for additional measures to protect pipelines from cracking-related phenomena. The following list provides some examples of potential measures:

— manage operational practices to reduce pressure cycling,

— perform in ditch inspections for cracks when the pipe is exposed for other reasons,

— adjust reassessment intervals or response criteria to reflect crack growth rates.

Additional guidance on preventive and mitigative measures is described in Section 16.

*Evaluate Crack Management Elements*—An operator should include metrics to evaluate the effectiveness of the crack management elements of their IMP. See Section 17 for additional guidance.

*Manage Change*—Operators should make sure the management of change systems implemented for effective IMP execution also capture the types of changes that would impact the elements of crack management.

*Update, Integrate, and Review Data*—After an integrity assessment with respect to the threat of cracking has been performed, the operator should incorporate the information acquired from the assessment into the appropriate crack management elements of their IMP. In addition, as the system continues to be operated, the accumulated operating, maintenance, and surveillance data should be collected for input into these elements. The various assessment processes should be adjusted, including the data integration and analysis protocols, time dependency classification method, and models for FFS and reassessment interval. The process should be repeated, if necessary, to arrive at the conclusion that the segment is fit for service until the next assessment.

# 6 Threat Mechanisms Associated with Cracking

## 6.1 General

The following sections provide details for understanding the general characteristics of the types of cracking addressed within this RP.

## 6.2 Environmentally Assisted Cracking

### 6.2.1 Stress Corrosion Cracking

SCC is a form of EAC where small cracks form and can continue to grow over a period of time. Typically, multiple small individual cracks form adjacent to one another in an array or colony. If the cracks continue to grow, they can overlap or coalesce to become the equivalent of a large single crack and must be treated as such when evaluating their effect on the pressure carrying capacity of the pipe. If crack growth continues, a crack can eventually develop large enough to cause the pipeline to leak or rupture.

Two modes of SCC in the soil environment are recognized: “classical” or high-pH SCC, and near-neutral pH SCC. The two modes occur under differing electrochemical environments that arise from the combined effects of local CP effectiveness, coating mechanical and electrical attributes, soil characteristics, and operating temperature. These are discussed at length in Annex A. SCC associated with transport of fuel grade ethanol (FGE) and FGE/gasoline blends is a distinctly different form discussed in 6.2.2. The following discussion applies specifically to external SCC in the soil environment. Figure 1 provides an example of an SCC crack field on the external surface of a pipe sample.



**Figure 1—External Surface of Pipe Sample with Sulfide Stress Cracking**

Three conditions must be present for SCC to occur: a susceptible material, a conducive environment, and a tensile stress.

— *Material*—All commonly used grades of line pipe steel are potentially susceptible. Susceptibility extends to pipe body, seam weld and girth weld deposits, weld heat-affected zones (HAZs), and in-line pipe fittings.

— *Environment*

1) High-pH SCC is associated with elevated temperatures compared to low-pH SCC, e.g. above 32 °C (90 °F), although no terrain condition is specifically associated with high-pH SCC at sites of coating damage, alkaline conditions at the pipe surface with pH higher than 9.3, and pipe surface potentials in the range of –600 mV to –750 mV (copper-copper sulfate) are indicative of the in situ conditions typically associated with the occurrence of high-pH SCC. High-pH SCC is most often located in the first 20 miles downstream of a facility that has historically run at an elevated temperature. In addition, high-pH SCC is commonly associated with coal tar coated pipelines.

2) Near-neutral pH SCC is associated with soil conditions that promote disbondment of coatings, pH levels in the range of 5.5 to 7.5, and electrochemical potentials in the free corrosion potential range indicative of shielding from the CP system. This mechanism is not associated with a specific temperature range. Bulk soil condition may range from aerobic to anaerobic, but conditions at the pipe surface associated with near-neutral pH SCC would be anaerobic. A common but nonexclusive example of conditions that can be conducive to near-neutral pH SCC is a pipeline coated with field-applied polyethylene (PE) tape or PE heat-shrink girth weld wraps, which remain intact when disbonded and electrically shield the pipe surface from cathodic current, located in clayey soils that retain moisture and exhibit a tendency to swell or shrink with moisture content promoting wrinkling or disbondment of the coating.



3) SCC has not been reported under a properly applied fusion-bonded epoxy (FBE) coating (excluding PE girth weld heat-shrink wraps used in conjunction with FBE or sites of coating damage in the absence of CP). The absence of SCC in conjunction with such a coating is attributable to the combined effects of FBE's mechanical resistance to soil stress, its nonshielding electrical properties, and compressive residual stress induced at the surface by the coating surface prep process. Extruded PE coating is also resistant to soil stress and disbonding, but it does shield the pipe from CP current. SCC has not been reported on pipelines with extruded PE (not including field-applied tape wrap systems).

4) SCC can only occur where coating is disbonded or damaged and where inadequate CP is available at the pipe surface. Inadequate CP can be due to inherent shielding properties of the coating or to external factors that affect CP effectiveness. If either the coating remains bonded to the pipe surface or adequate CP potentials (per NACE SP0169) are achieved at the pipe surface anywhere the coating is not intact, SCC does not occur. Coating failure can occur on any portion of the pipe; it can also occur preferentially, for example, tenting of tape coating over a double submerged arc welding (DSAW) seam.

5) Minor surface corrosion can be present with near-neutral pH SCC or absent in the case of high-pH SCC. Near-neutral pH SCC has been observed to occur in association with microbiologically influenced corrosion (MIC) pitting.

— *Stress Level*—A stress level of 60 % of SMYS is generally regarded as the threshold for susceptibility to SCC, although SCC has been identified in pipelines operated at lower stress levels typically associated with localized phenomena such as dents or gouges. SCC has been identified at points of stress concentration such as weld toes and mechanical damage. Residual stresses from pipe forming or welding can also contribute to susceptibility. Circumferentially oriented SCC has occurred where longitudinal stresses due to soil movement exceed a stress threshold, even in pipelines operating at very low levels of hoop stress.

Refer to Annex A for further discussion of the relative importance of causal factors and their relationships.

### 6.2.2 Other Forms of Environmentally Assisted Cracking

Pipelines that transport products containing free water and gaseous hydrogen sulfide ($H_2S$) at normal operating pressures can be susceptible to other forms of cracking including sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), or stress-oriented hydrogen-induced cracking (SOHIC). In a sour environment, a significant atomic hydrogen flux can be produced by corrosion reactions of water or $H_2S$.

SSC is a form of hydrogen embrittlement that can affect line pipe steel exposed to $H_2S$ and water while the material is subjected to tensile stress. A cathodic reaction in the presence of $H_2S$ and water can allow atomic hydrogen to diffuse into the steel. Normally, this does not affect the base metal of line pipe steel, but if weldments on the pipe have created HAZs with hardness of Rockwell C 22 (HRC 22) or more, cracking can occur. The phenomenon can be mitigated by preheating the material before welding or by postweld heat treatment (PWHT) to eliminate zones of high hardness. Higher hardness thresholds for susceptibility to cracking in sour service, e.g. HRC 30, may apply to materials other than carbon steel and low-alloy steel. [Note that hardness thresholds for susceptibility to cracking in sour service are not to be confused with hardness thresholds for susceptibility to hydrogen-assisted cracking (HAC) or cold cracking associated with welding high carbon-equivalent steels under high cooling-rate conditions, as may occur with repair welds made in service.]

Also, HIC and SOHIC are threats associated with the diffusion of atomic hydrogen that collects at inclusions and recombines into molecular hydrogen. Because molecular hydrogen is much larger than atomic hydrogen, it does not readily diffuse away; pressure and internal stress builds as hydrogen accumulates. The interaction of stress fields surrounding the blisters results in HIC, characterized by step-wise internal cracks that link adjacent, non-coplanar blisters. An external stress is unnecessary for HIC to occur. SOHIC occurs as an array of blisters stacked in the through-thickness direction and linked by HIC. SOHIC usually occurs in the base metal adjacent to a weld HAZ, where welding residual stress provides the crack-driving force. Unlike SSC, both HIC and SOHIC can occur in the normal line pipe material where high $H_2S$ partial pressures and intense hydrogen charging are present; high hardness is not necessary.



Prevention of SSC, HIC, and SOHIC requires treatment to reduce free water and/or the use of an inhibitor to prevent the cathodic reaction between water and $H_2S$.

More information about the phenomena of SSC, HIC, and SOHIC is available from the following.

— NACE MR0175/ISO 15156:2007, Part 1, Part 2, and Part 3;

— API 945;

— Pargeter, R.J., "Susceptibility to SOHIC for Linepipe and Pressure Vessel Steels—Review of Current Knowledge," Corrosion 2007, Paper 07115, NACE International, Nashville, Tennessee, March 11–15, 2007.

Hard spots, or hard zones on the seam line, having hardness levels in excess of 250 Hv10 (22 Rockwell C) are prone to hydrogen embrittlement and/or stress cracking in the presence of a significant atomic hydrogen flux. Sources of atomic hydrogen arise internally in the transport of sour gas containing free water, or externally from high CP potentials. Service failures have occurred as a result of exposure of hard spots or hard zones to either of these environments. The creation of hard spots is also associated with high carbon equivalent, which was allowed in the upper range of older versions of API 5L by some pipe mills. Additional information regarding a pipe manufacturer's susceptibility to hard spots can be found in the INGAA report "Integrity Characteristics of Vintage Pipelines."

Hydrogen also has a deleterious effect on steel properties. Generally lower toughness can be expected in addition to accelerated crack growth due to fatigue. This can become an issue due to corrosion reactions of the steel with sour service or due to high CP levels as discussed. One number is not universally applicable, as the potential threshold for evolution of hydrogen is an artifact of the pH and temperture as defined in the Nernst equation.

Facilities that handle neat FGE and FGE/gasoline blends (or to a lesser extent, methanol) are susceptible to a form of SCC due to exposure to the product under certain conditions. Susceptibility is associated with hardness and residual stress levels in seams and girth welds and high applied stresses. Susceptibility factors associated with the product include moisture levels and degree of oxygenation. Controlling ethanol-exposure SCC usually involves practicing PWHT, managing piping thermal expansion flexibility stresses, and focusing on fluid-handling practices. Refer to API 939-D.

More information about the phenomenon of ethanol service is available from the following:

— API 939-D;

— Chambers, B., et al, "Determine New Design and Construction Techniques for Transportation of Ethanol and Ethanol/Gasoline Blends in New Pipelines," U.S. DOT, Pipeline and Hazardous Materials Safety Administration, Contract No. DTPH56-09-T0000003, Final Report, February 15, 2013;

— Kane, R.D., et al, "Stress Corrosion Cracking in Fuel Ethanol: A Newly Recognized Phenomenon," Corrosion 2004, Paper No. 04543, NACE International.

## 6.3 Manufacturing Defects Associated with Longitudinal Seams

### 6.3.1 General

No type of pipe manufacturing process, both past and present, is inherently a defect-free process. Generally, pipe that has been inspected in the mill and that successfully undergoes a post-construction hydrostatic test to a minimum level of 1.25 times the MOP/MAOP does not contain flaws that result in failures later in service in the absence of a growth mechanism. The following sections define the types of crack flaws that can be present based on the manufacturing process. Refer to Section 11 for methods to inspect for these types of defects.



### 6.3.2 Electric Resistance Welded and Electric Flash-welded Seams

ERW seams include the direct current (DC), low-frequency (LF), and high-frequency (HF) processes. The types of flaws associated with ERW and EFW seams that are cracks or other stress concentrators increase the likelihood for failure due to crack growth by fatigue. Examples of manufacturing flaws susceptible to crack initiation and fatigue crack growth include hook cracks, lack-of-fusion (also referred to as cold welds in API 5T1), mismatched plate edges, and hard spots. Hook cracks are separations that result from imperfections at the edge of the skelp that lie in-plane. During the welding process, these imperfections are upset and turn towards the ID or OD surface. An example of a hook crack in LF pipe is shown in Figure 2. In this photo, the hook crack is from the OD surface to the left of the bondline. A fatigue crack is also present from the end of the hook crack to the OD surface. The hook cracks follow the upturned fiber pattern near the bondline. Figure 3 depicts another hook crack in a flash-welded pipe.

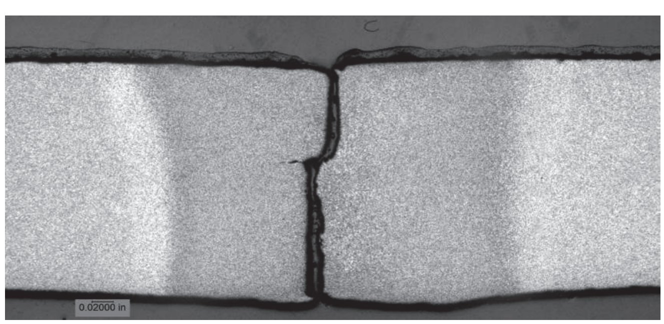
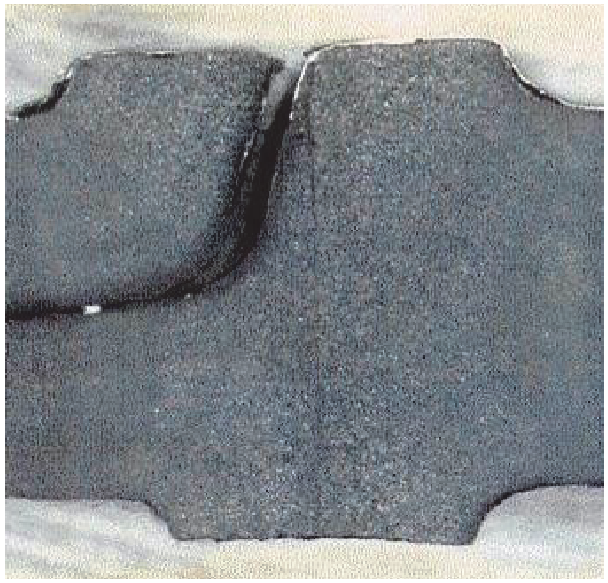



**Figure 2—Hook Crack and Fatigue Crack Extension in Low-frequency Electric Resistance Welding Pipe**



Note the square inside and outside flash.

**Figure 3—Hook Crack in Flash-welded Pipe**

Vintage skelp produced by the open-hearth processes is known to have higher levels of impurities such as sulfur and is much more likely to produce hook cracks than modern steels with low sulfur content. The low sulfur steel that is possible with the basic oxygen process leads to fewer inclusions and laminations that are the source of hook cracks. Laminations are generally considered benign unless they contribute to the formation of a hydrogen blister, are oriented in a manner where they can eventually growth to the inner or outer wall of the pipe through pressure cycles, or intersect another stress riser such as a girth or seam weld. Because it is associated with the steel-making process, the presence of hook cracks is not restricted to LF. The timeframe of 1979 through 1985 is when most of the mills abandoned open hearth steel making for basic oxygen steel making. From this standpoint, HF pipe made from open-hearth steel can pose a similar risk as LF pipe. There is one significant difference between the processes that should be noted: LF welding produced large HAZs and substantial grain coarsening in the HAZ, resulting in particularly low toughness and to a ductile to brittle transition temperature that can be at or above ambient temperature. The grain coarsening is typically not reversible by heat treatment in accordance with API 5L production requirements. The typical LF HAZ generally possesses low toughness at ambient temperature. HF, in contrast, tends to have a higher toughness and a lower transition temperature in the HAZ compared with low-frequency electric resistance welding (LF-ERW) HAZ. The low toughness LF-ERW pipe has been a factor in a number of in-service failures over the years.



An example of lack-of-fusion (also called cold welds) is shown in Figure 4. This type of weld defect results from inadequate heat and/or pressure during the ERW forming process. Lack-of-fusion defects can be part-wall or through-wall defects, also called penetrators. These types of defects were more common in older DC and LF welded materials than in HF welded materials. Those flaws that are not detected during mill hydrostatic testing or NDE typically contain high-temperature oxides along the bondline that prevent leakage, in some cases even when tested to 1.25 times the operating pressure.

An example of offset skelp edges is shown in Figure 5. The offset of the right side skelp resulted in an angled bondline. API 5L has limits on the allowable offset of plate edges, as severe offset produces stress concentration, which can lead to fatigue.

Pipeline and Hazardous Materials Safety Administration's (PHMSA's) 2004 Technical Task Order 5 "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation" provides a process for identifying pipelines for inclusion in a baseline assessment program. The guidelines included in Annex B are aimed at assisting pipeline operators in prioritizing an ERW or flash-welded threat in their pipeline systems and implementing effective mitigation programs for reassessment determination.

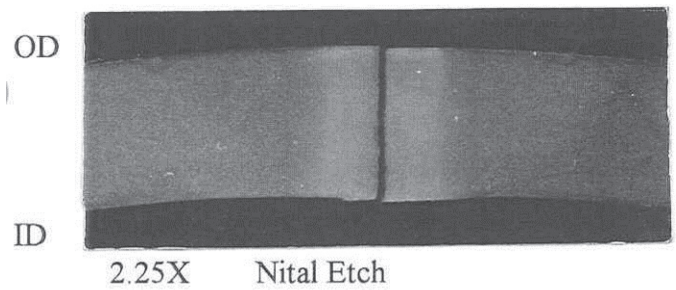



**Figure 4—Lack-of-Fusion Defect**

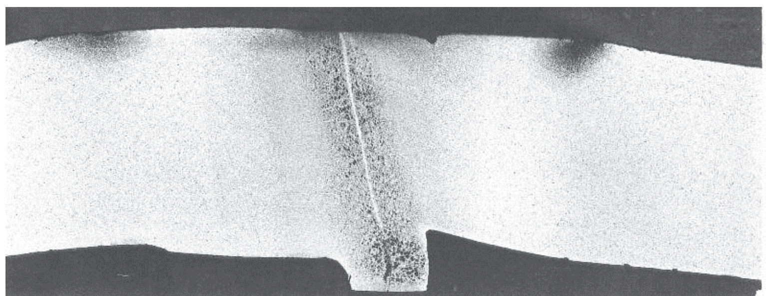


**Figure 5—Direct Current Welded Seam with Offset Skelp Edges**



### 6.3.3 Submerged Arc Welded Seams

Although not generally deemed as high of a risk as ERW pipe, submerged arc welded (SAW) pipe (currently only made using a double-submerged process) has experienced weld metal cracks and toe cracks. Weld metal cracks can arise during the manufacturing process when movement of the plate edges occurs before the weld metal has cooled sufficiently. An example of this is shown in Figure 6. A toe crack, as shown in Figure 7, can result during cold expansion because of imperfectly round cans or excessively high weld bead crowns. They can form at either the OD or ID surface where the crown of the DSAW bead intersects the plate. Those weld metal cracks and toe cracks that survive initial hydrostatic testing can enlarge in service due to pressure-cycle-induced fatigue. The example in Figure 7 also contains offset, which can lead to lack-of-fusion between the weld passes.

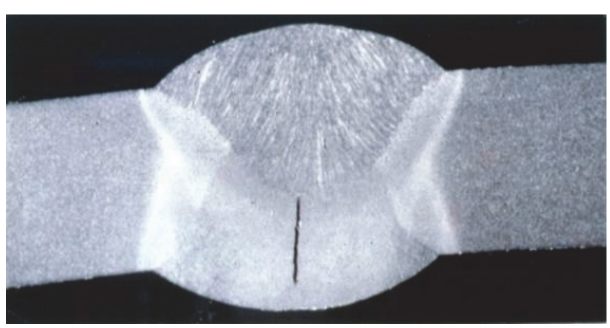


**Figure 6—Weld Metal Crack (Hot Crack)**

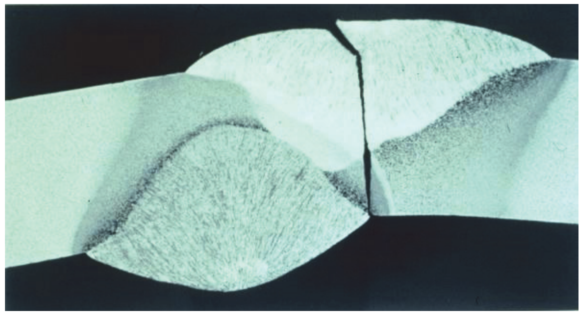


**Figure 7—Toe Crack (Also Contains Offset)**

Transit fatigue that arises from transportation of line pipe, typically by rail car and the associated improper loading, can contribute to toe cracking. Fatigue cracks of this type can be small enough to survive the initial commissioning hydrostatic test of a pipeline, but they can become large enough to cause an in-service failure of a pipeline through pressure cycle-induced fatigue.

Prior to the DSAW process, longitudinal seams were fabricated using the SAW process, but with the weld metal deposited only from the outside of the pipe. Such seams were called single SAW (SSAW). SSAW seams can contain lack-of-fusion defects near the root of the weld, which can be susceptible to fatigue crack growth. While SSAW was prohibited in API 5L after 1949, operators could still purchase SSAW pipe by agreement with the mill beyond this date.

## 6.4 Mechanical Damage

### 6.4.1 Definition of Mechanical Damage



"Mechanical damage" refers to damage to the pipe caused by locally concentrated external loadings acting in direct contact or impingement against the surface of the pipe. Examples of situations that can cause mechanical damage include the following:

— rocks or other objects embedded in the backfill bearing against the pipe from below, the side, or above the pipe;

— components of excavating equipment or other types of equipment (e.g. dozers, augers, trenchers) working in the soil at pipeline depth and contacting or striking the pipe;

— objects falling onto or driven against exposed pipe;

— contact between the pipe and ground, structures, or equipment during the transport or handling of the pipe.

As recognized in this document, mechanical damage encompasses the following conditions that can promote cracking under specific circumstances:

— plain indentations or distortions of the pipe circular cross section ("plain" means no scrape or gouge is present, although other adverse factors could be present such as particular geometric features or close proximity to welds or other indentations),

— scrapes or gouges of the pipe surface within indentations,

— scrapes or gouges of the pipe surface without visible or apparent indentation.

Many pipeline regulations or industry standards provide for specific treatment of mechanical damage depending on depth, location, and presence or interaction with other pipeline features. The operator should observe or comply with such provisions where applicable. Where such provisions are not strictly applicable either based on jurisdiction or because they are not appropriate to the circumstance, the operator should nevertheless recognize that the potential for cracking to be associated with mechanical damage could exist and take appropriate steps to evaluate the damage and respond accordingly. Degradation mechanisms that can lead to cracking in association with mechanical damage and methods for evaluating severity of the condition are discussed below.

### 6.4.2 Plain Indentations

Plain indentations do not immediately reduce the burst strength of the pipe; however, certain dent geometries and/or susceptible environments could potentially result in cracking and eventual failure, typically as a leak. These include the following.

— Highly localized indentations (often called "sharp dents"), even where the absolute indentation depth is minor but able to increase over time, can be susceptible to shear cracks from excessive strain.

— Plain indentations containing multiple apexes or single apex indentations spaced nearby other indentations are susceptible to fatigue from pressure cycles, particularly in the "saddle" area having reduced curvature between the apexes.

— Highly localized indentations or indentations containing multiple apexes may be susceptible to SCC when areas of local curvature (strain) are high enough to produce residual surface stresses above the threshold for SCC, and coating damage or disbondment and a conducive environmental condition is present at the pipe surface. Fatigue crack growth may also contribute to through-wall cracking.

— Plain indentations that intersect seams or girth welds have reduced tolerance for pressure cycles or strains of deformation compared to dents affecting pipe body.



— Plain indentations that have been excavated and that have had the indenting object removed such that the pipe circular cross section can partially re-round under internal pressure are susceptible to fatigue from pressure cycles acting on the unrestrained residual dent.

— Bearing stresses can damage coating while the rock or other object can impair CP effectiveness, resulting in metal loss corrosion or SCC.

A number of analytical techniques can be applied to the assessment of plain indentations to estimate local strain to evaluate the potential for cracking and to estimate fatigue life due to stress concentration or dent flexibility.

Locally concentrated indentations (often referred to as "sharp dents" in ILI reports), as well as indentations that exceed limits in applicable codes and standards allowances based on dent depth, may be evaluated for excessive strains of deformation by analysis of altered curvatures within the indentation inferred by geometry ILI. [47] [52]

The strain analysis is performed as an alternative to evaluating dent severity based on indentation depth alone since depth is a poor indicator of the susceptibility to cracking from excessive local strains. Dent strain analysis involves considerable analytical complexity and is affected by error inherent to the geometry measurement process. Local strains may be compared against a material strain capacity criterion appropriate for the affected pipe material, including a suitable factor of safety. Indentation depths and/or curvatures indicated by ILI may require adjustment to account for re-rounding effects if restraint of the indentation is incomplete or removed.

The strain analysis is an effective tool for evaluating susceptibility to cracking due to excessive local strains, but it is not an effective method for estimating susceptibility to fatigue from pressure cycles. Pressure cycles can cause a re-rounded unrestrained dent to fluctuate radially, leading to fatigue cracking. Even with a restrained dent, stress concentration effects at the leading and trailing zone in the periphery of the dent can result in fatigue crack initiation and growth due to reduced stiffness associated with the very low curvature in the portion of the dent situated between regions of opposite curvatures. [39] Other regions of an indentation can also experience cracking. Researchers have developed stress concentration factors based on indentation geometry [33] as well as other associated features such as welds, [47] or use finite element analysis on a case-by-case basis. The results may then be used to estimate a fatigue life.

### 6.4.3 Damage Involving Scrapes or Gouges

The damage process associated with accidental contact between excavating equipment of any kind or any other dynamic impingement between hard foreign objects and the pipe surface is complex and situationally dependent. Such damage usually involves some transient indentation of the pipe (which can re-round to negligible levels after contact due to internal pipe pressure) and extreme surface shear stresses, resulting in significant damage at the surface and subsurface to the affected area. The damage can include the following:

— smearing and large plastic deformation at the pipe surface,

— metal loss associated with gouging,

— cold work of surface and subsurface layers due to crushing of microstructure,

— microstructural transformation (potentially including untempered martensite) due to the locally rapid heating and quenching associated with unlubricated metal-to-metal friction,

— surface cracking transverse to the direction of relative motion due to transient thermal stresses caused by the frictional heat-quench cycle,

— surface cracking in the regions affected by microstructure transformation or cold work as a result of dynamic re-rounding of the initial transient indentation,



— surface cracking from construction damage after re-rounding during a hydrostatic test.

The extent to which these conditions are present is affected by many factors, including pipe geometry, pipe operating conditions, pipe metallurgy, the geometry of the contacting object, the relative motion of the contacting object, and the striking force. In general, much of the information necessary to develop a precise understanding of the damage present is unavailable.

The time-dependent failure mechanisms that could lead to failure in mechanical damage involving a scrape or gouge include, but are not limited to, the following:

— fatigue crack growth due to pressure cycles,

— corrosion of damaged and exposed surfaces where the coating was penetrated (corrosion is mentioned for completeness but it is not a cracking mechanism),

— SCC of damaged and exposed surfaces,

— crack advancement by stable or unstable tearing due to sustained stresses near the point of failure,

— crack advancement by stable or unstable tearing during a subsequent normal or abnormal pressure increase.

Currently, no authoritative consensus approach exists for evaluating the failure pressure or time to failure of mechanical damage that involves a scrape or gouge. Theoretical models have been described in the research literature, but they generally exhibit considerable scatter relative to tests or actual materials performance. An operator may use such models for screening or prioritization, but should apply due consideration for uncertainty concerning the conditions that gave rise to damage as well as to the extent and severity of actual damage present. Currently successful management of cracking associated with damage of this type involves an active damage prevention program, periodic inspection capable of indicating the presence of mechanical damage that could consist of a scrape or gouge, prompt investigations of any evidence of such damage, and implementation of suitable repairs. Repairs are discussed in Section 15 of this document and can include treatment by buffing out the damaged layers of metal within specified limits, including removal of cracks, so as to convert the damage to a plain metal loss feature within the residual dent (if present).

# 7 Fitness-For-Service of Crack-like Flaws

## 7.1 Assessment Methods

It is essential that appropriate methods are used for the assessment of crack-like flaws in pipelines. The applicability and limitations of the methods used should be clearly understood by the analyst. The most common methodologies that have been used in the pipeline industry include the following:

— Battelle model (Modified Log-secant),

— CorLAS™,

— API 579-1/ASME FFS-1, Part 9.

NOTE This is not meant to be a comprehensive list, and other methods may be appropriate for a particular application. These approaches all provide methods to evaluate cracks identified with ILI, ITD NDE, or to establish the maximum survivable flaw size following hydrostatic testing. The Battelle model (Modified Log-Secant model) is a plastic collapse based approach, where predicted burst pressures are largely insensitive to toughness, and therefore can be nonconservative for Charpy V-notch (CVN) impact values below 20 J (15 ft-lb). In these cases, the Modified Log-secant model may be supplemented with the Raju Newman equation. CorLAS™ is a simplified J-integral based fracture model based on finite element solutions for a flat plate, with an approximate correction for pipe curvature. The Level 2 methodology in API 579-1/ASME FFS-1, Part 9 is based on a failure assessment diagram (FAD), which accounts for brittle fracture, plastic collapse, and mixed modes (elastic-plastic) of failure between these two extremes. Details of these approaches are described in Annex C.



## 7.2 Input Parameters

### 7.2.1 General

Operators should be aware that error and uncertainty are inherent to the assessment process and affect the results. Sources of error or uncertainty include the following:

— simplifying assumptions embodied in theoretical formulations,

— characterization and sizing of defects,

— variability in material properties,

— variability in dimensions of pipe wall and other geometries,

— stress patterns induced by geometric effects within or near features of interest,

— uncertainty or variability in applied loadings,

— potential effects of environmental factors on material properties and fatigue crack growth rate.

Often one can readily make reasonable assumptions concerning pipe dimensions, material properties, and applied stresses that are sufficiently appropriate to obtain meaningful assessment results. The operator should consider whether expected ranges of input parameter variability or measurement error can affect or degrade the accuracy of the assessment to a degree that could influence integrity decisions. In making this consideration, the operator should determine whether the objective of the assessment is to obtain a result that is conservative (i.e. erring on the side of safety) to a high degree of certainty or that is a best estimate (i.e. most likely to be accurate). Assessments consistent with these two objectives rarely produce the same result. See 7.2.5 for additional guidance on selecting appropriate material properties.

### 7.2.2 Material Strength

Destructive material testing and reviews of material test reports from manufacture have shown that the yield strength and tensile strengths can be above the specified minimum. The use of a specified minimum or an upper bound value have an effect on the calculations with respect to failure due to elastic-plastic or plastic collapse (ductile failure). In the absence of actual material strength data, the data provided in Annex D may be used. The data in Annex D were derived from actual tensile test data representing pipe grades from A to X70.

### 7.2.3 Material Toughness

Toughness is a property that quantifies the material's resistance to fracture in the presence of a crack or crack-like imperfection. It is a key parameter in the FFS assessment methods. The toughness measure varies with temperature and the testing technique. Toughness measure values should be considered for the pipe body, HAZ, or bondline depending on where the defect is located. Refer to Annex E for more information.

### 7.2.4 Flaw Sizes

Characterization of flaw type and geometry is challenging when performing a crack assessment. Estimation of the maximum possible flaw size using ILI must incorporate detailed knowledge of the inspection tools used and analysis of the data (see Section 11), as well as conducting validation excavations using appropriate NDE techniques (see Section 14). Estimation of the maximum flaw size using a hydrostatic test must incorporate test pressure levels and material properties, though no information is provided on the location or existence of any subcritical flaws. Here the maximum size flaw that is estimated to survive the test pressure is used as input into the FFS calculations or to establish the initial flaw dimensions as input to a fatigue crack growth assessment.



### 7.2.5 Considerations for Selecting Material Properties

If the objective of the FFS analysis is to obtain a conservative result with a high degree of certainty, material properties and other input should be selected, accounting for the effect of those assumptions in the assessment. Where the value of input parameters can vary over a range, lower bound or upper bound values should be selected accordingly. For example, given a flaw size and stress level, selecting SMYS or lower bound toughness leads to a conservative estimate of failure pressure. On the other hand, when estimating time to failure after a pressure test, assuming upper bound yield strength and toughness have the effect of maximizing initial postulated flaw sizes to predict the shortest predicted time to failure. However, the operator is cautioned against combining inconsistent input data within a single assessment as this could lead to excessively conservative results.

If the objective is to obtain a best estimate, then all input should represent the most likely or probable values, which sometimes is represented by a mean value where the parameter can be characterized by a statistical distribution. For example, extensive pipe mill data, if available, can support selection of typical material properties that differ from specified minimum values. The resulting assessment would be expected to be more realistic and is more likely to be accurate than one obtained using unrepresentative input values.

It would not be appropriate to use upper bound values to determine the size of just-surviving flaws and then use lower bound values to determine a fatigue life. The value that is selected the should remain the same throughout all phases of the analysis.

### 7.2.6 Other Inputs

A further consideration in characterizing the mechanical properties is the effect of the surrounding environment. Hydrogen can have detrimental effects on toughness as well as fatigue crack growth rates. High hardness materials can be susceptible to hydrogen assisted cracking, where hardness exceeds about Rockwell C 22, either in the weld or at a hard spot. This is most often a factor for pipelines operated with very high CP potentials, wet soil conditions, and where the coating integrity is suspect. Hydrogen effects can also become a factor in sour service. (This document does not define "sour service." Definitions for sour service differ among the various applicable standards and guidelines. See for example, Bush, D., "An Overview of NACE International Standard MR0103 and Comparison with NACE MR0175," Paper No. 04649, NACE Corrosion 2004.) However, hydrogen embrittlement is considered a threat only when all the conditions described are present. Additional insight into the potential for hydrogen embrittlement can be gained through knowledge of the pipe fabricator. Guidance on hydrogen effects on mechanical properties is included in Annex F.

Under some circumstances, residual stresses or local bending stresses should be considered, e.g. due to pipe forming practices unique to specific manufacturers, where pronounced angular misalignment across the seam occurs or where the material is brittle. Of the three fracture mechanics methods described in 7.1, API 579-1/ASME FFS-1 is the only approach that can incorporate residual or bending stress effects.

# 8 Crack Growth

## 8.1 Pressure Cycling Analysis

### 8.1.1 General

Cyclical loading arises from fluctuations in the internal pressure of the pipe. This is of particular concern for hazardous liquid pipelines and can result in crack growth by fatigue. The rate at which crack growth can occur is primarily a function of the amplitude and frequency of the pressure cycles. In some cases, environmental factors can result in accelerated crack growth rate that must be considered when performing an analysis as mentioned previously. Fatigue crack growth can occur at manufacturing defects, such as hook cracks and cracks formed during transit in ERW, EFW, and SAW pipes.



### 8.1.2 Data Gathering and Frequency

*Liquid Pipelines*—Pressure data should be gathered at each operating pump station discharge location and suction location and any intermediate pressure sources as applicable. Pressure data should be gathered on a change in pressure above a certain threshold, such as 10 psig, sometimes referred to "change of state." Alternatively, the sampling interval can be taken at fixed intervals not to exceed an interval that is appropriate based on an understanding of the pipeline operation. This interval may need to be as short as 1 minute for some pipelines but can be as long as 5 minutes, though longer intervals are not recommended for any systems. The more granular the data, the more accurate the fatigue life calculation will be. To capture the effects of seasonal operational changes, a minimum of 1 year of pressure data should be analyzed. If possible, data should be gathered from the date of the last seam assessment.

*Gas Pipelines*—Although the pressure cycles experienced on a gas line are not typically significant enough to support fatigue growth, where anomalous operation can warrant further analysis, pressure data should be gathered at each compressor station location. The sampling interval should not exceed 1 hour where minimum and maximum pressures are available during the hour. The more granular the data, the more accurate the fatigue life calculation will be. A pressure spectrum can be built using the minimum and maximum pressures so that any fluctuations are captured. For conservatism, the pressures should be combined such that the largest number of pressure cycles result. A minimum of 1 year of pressure data should be analyzed. If possible, data should be gathered from the date of the last seam assessment.

### 8.1.3 Applying Data (Location)

The segmentation of hydrostatic testing or anomalies identified through ILI can drive a need to determine the pressure spectra for points on a pipeline between pressure locations. Equation (1) can be used to determine the pressures at the location, provided the time stamps do match. Gathering pressure data based on pressure change can result in the upstream and downstream pressures having different time stamps. An algorithm should be used to interpolate between data points to facilitate use of the equation when intermediate pressure data need to be calculated. Calculating location-specific pressure data need not be necessary for gas pipelines due to the lack of appreciable change of a hydraulic gradient.

$$P_x = (P_1 + K \cdot h_1 - P_2 - K \cdot h_2)\left(\frac{1}{\dfrac{(L_x - L_1) \cdot D_2^5}{(L_2 - L_x) \cdot D_1^5} + 1}\right) - K(h_x - h_2) + P_2 \tag{1}$$

where

$P_x$ Intermediate pressure point between pressure sources, psig;

$P_1$ upstream discharge pressure, psig;

$P_2$ downstream suction pressure, psig;

$K$ SG × (0.433 psi/ft), where SG = specific gravity of product;

$L_1$ location of upstream discharge station, ft;

$L_2$ location of downstream suction station, ft;

$L_x$ location of point analysis, ft;



$h_1$ elevation of upstream discharge station, ft;

$h_2$ elevation of downstream suction station, ft;

$h_x$ elevation of point analysis, ft;

$D_1$ pipe diameter of segment between $L_1$ and $L_x$, in.;

$D_2$ pipe diameter of segment between $L_x$ and $L_2$, in.

### 8.1.4 Data Processing

The assessment for in-service flaw growth due to cyclical loading is an integral part of managing a crack threat. The basic procedure begins with gathering operating pressure data; an example spectrum is shown in Figure 8 and described in 8.1.2. The pressure cycle data are used to establish the pipeline loading history. In most cases, the pressure data indicate that the line experiences fluctuating pressure cycles and, therefore, is subject to fatigue due to variable loading conditions. It is important that the data are reviewed to remove any anomalous pressure values that are not representative of actual operations.

The most common approach to evaluate variable loading from the pressure spectra is referred to as "rainflow counting" (ASTM E1049-85). Rainflow counting is an algorithm that was developed to analyze pressure data by reducing the loading history into a sequence of peaks and valleys. A load histogram, shown in Figure 9, is produced from the peaks and valleys to provide an estimate of the total number and magnitude of pressure cycles that have occurred during the time period under consideration. If the fatigue life calculation relies on a histogram of the number of pressure cycles in categories of magnitude, then operators should carefully select the bin sizes used for the analysis, as large bin sizes may result in overly conservative fatigue lives.

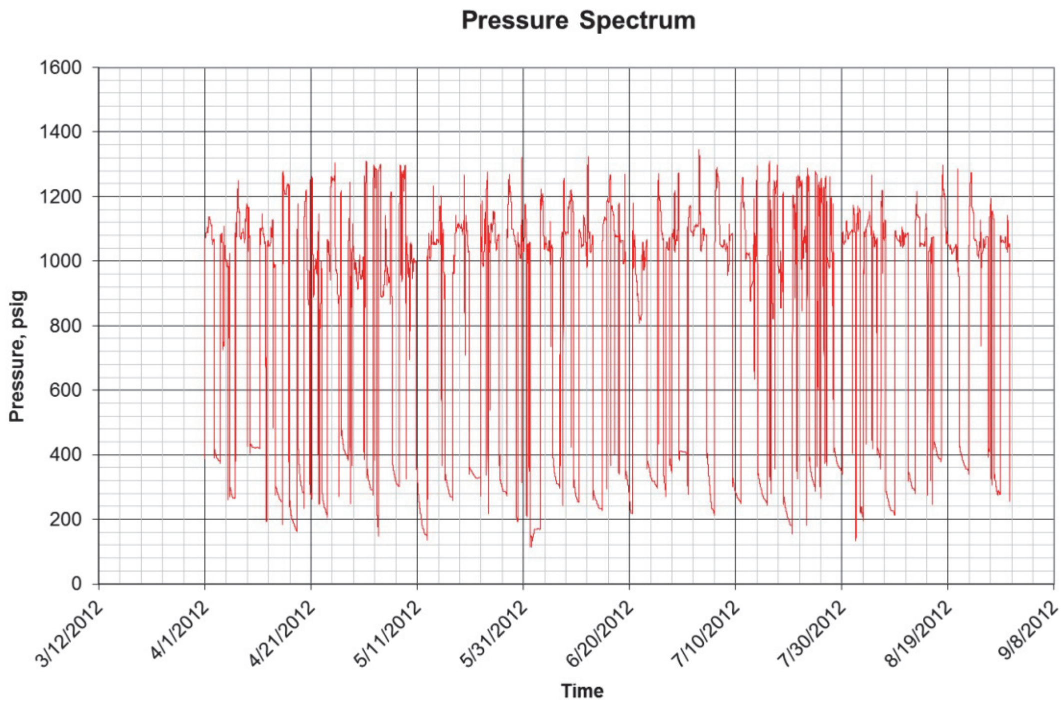



**Figure 8—Example Pressure Spectrum from a Liquid Pipeline**



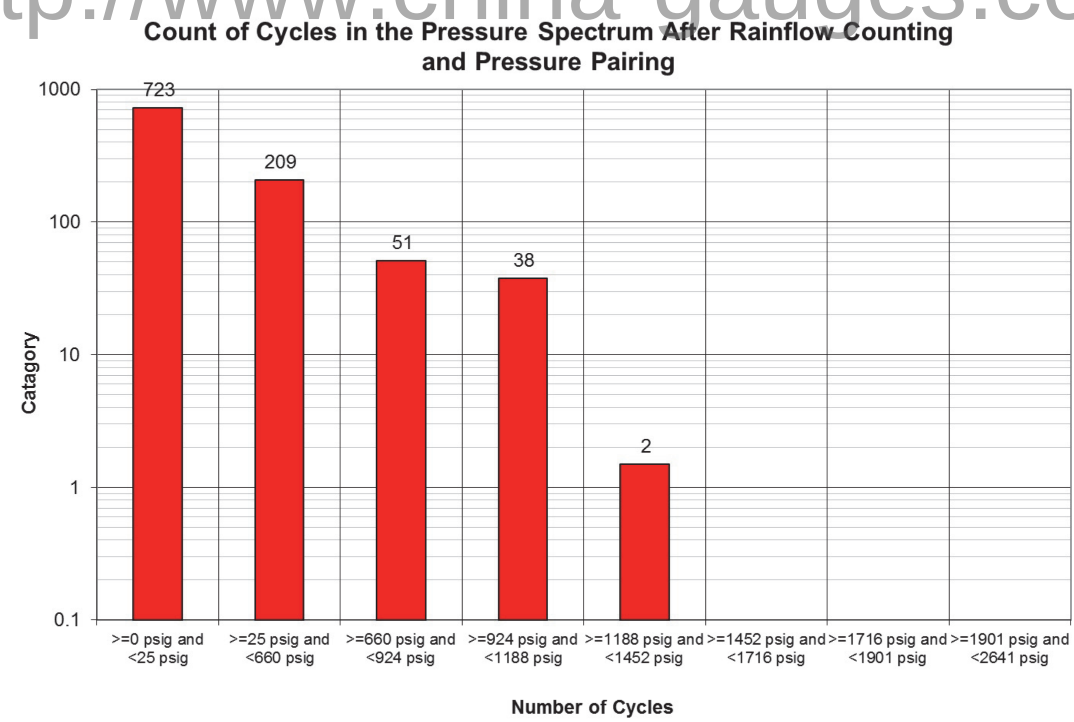



**Figure 9—Example Histogram Resulting from Rainflow Cycle Counting**

## 8.2 Fatigue Growth

### 8.2.1 Paris Law

Fatigue crack growth generally follows a "Paris Law" relationship wherein the log of the rate of fatigue crack growth varies linearly with the log of the change in applied stress intensity factor associated with a given stress (i.e. pressure) cycle. Mathematically, the Paris Law relationship is Equation (2):

$$\frac{da}{dN} = C\left(\Delta K\right)^m \tag{2}$$

where

$\frac{da}{dN}$ is the incremental crack growth length ( $a$ ) per number of loading cycle ( $n$ ) (inches per cycle in U.S. customary units);

$C$ and $m$ are constants that depend on the material and the environment;

$\Delta K$ is the change in stress intensity factor per cycle (psi-root-inch in U.S. customary units).

$\Delta K$ is usually expressed in a form such as the following, although other equations [see Equation (3)] may be used:

$$\Delta K = C_1 \Delta S \sqrt{\frac{\pi a}{Q}} \tag{3}$$



where

$C_1$ is the incremental crack growth length ( $a$ ) per number of loading cycle ( $n$ ) (inches per cycle in U.S. customary units);

$\Delta S$ is the change in hoop stress (psi in U.S. customary units);

$a$ is the current crack depth (inch in U.S. customary units);

$Q$ is a flaw shape parameter that is a function of the depth/length ratio of the crack and in some models also varies with applied stress

Because $\Delta K$ is a function of both the change in hoop stress and the current crack depth, the rate of fatigue crack growth is not be constant over time. The rate of fatigue crack growth tends to accelerate as the crack enlarges. This effect can sometimes be partially offset temporarily by reducing the magnitude and frequency of stress or pressure cycles in operation.

The Paris Law approach should be incorporated into a model that calculates the time it takes for the incremental crack growth to occur during each cycle to reach a critical size. The time to reach the critical size determines the remaining life and a subsequent reassessment interval, incorporating an appropriate factor of safety. An operator may elect to account for additional factors in the crack growth model, such as thresholds, mean stress effects, or seam misalignment.

Paris Law fatigue crack growth parameters $C$ and $m$ are determined from laboratory testing. Their values are not controlled by pipe product specifications, nor are they tied in a predictable way to common pipe grade specified properties that a typical pipeline operator has knowledge about. In environments potentially representative of pipeline service, the constant $C$ has been found to vary over a range of several orders of magnitude, while the exponent $n$ usually ranges from somewhat less than three to somewhat greater than five. API 579-1/ASME FFS-1 provides values for $C$ and $m$ for performing fatigue crack growth analysis of welds in steel. Other sources of Paris Law constants are provided in BS 7910, which provides statistical bounds for the constants $C$ and $m$, and recent Pipeline Research Council International (PRCI) studies.

A survey of reported fatigue crack growth parameters for line pipe is summarized in Annex G. Corrosive or hydrogen enriched environments can increase crack growth rates by an order of magnitude compared with rates for nonaggressive environments.

### 8.2.2 Miner's Rule

Miner's Rule, also known as the Miner-Palmgren Linear Cumulative Damage Law, is one of several methods for accounting for the effects of variable amplitude loading on fatigue life. It is expressed in Equation (4):

$$\sum_k [n_k / N(\Delta\sigma_k)] = 1 \tag{4}$$

where

$n_k$ is the number of occurrences of stress cycles of $k^{\text{th}}$ amplitude $\Delta\sigma_k$;

$N(\Delta\sigma_k)$ is the number of cycles to failure corresponding to uniform cyclic loading of amplitude $\Delta\sigma_k$.

Failure under variable amplitude loading is expected when the cumulative sum of damage from all cycles of each $k^{\text{th}}$ amplitude equals 1. Miner's Rule is a special case of the concept of cumulative damage and is the most widely used due to its simplicity. There is no general proof that Miner's Rule or any other cumulative damage theory is always optimal. [31] Experience shows Miner's Rule to provide generally useful estimates of fatigue life in many cases, especially where most of the damage occurs from a narrow range of stress amplitudes either due to a dominant quantity or amplitude of cycles. Selecting overly broad amplitude range bins for cycle counting degrades the effectiveness of any cumulative damage approach for estimating fatigue life.



Miner's Rule or another cumulative damage law may be applied to a cycle-counted pressure record to estimate an equivalent number of full zero-to-maximum pressure or stress levels for the sample period. The Paris Law can, in principle, be integrated between an initial and final crack depth, to estimate a number of constant-amplitude zero-to-maximum cycles to failure. (If necessary to facilitate the integration, the operator may apply judicious simplifications to the crack tip stress-intensity relationship.) The time to failure is then the number of cycles to failure determined from the integrated Paris Law to the number of Miner's Rule equivalent cycles normalized to a reference time period. This approach can be an attractive alternative to an incremental crack growth analysis in that it can produce similar (although not identical) results with reduced computational effort.

### 8.2.3 Threshold Effects

Fatigue crack growth does not occur from an existing crack-like defect below a threshold of stress-intensity $\Delta K_{\text{th}}$. While ignoring crack-growth thresholds leads to a more conservative (i.e. shorter) calculated time to failure than disregarding the threshold, this is not recommended in situations that involve large numbers of very small-amplitude cycles. The reason for this is that it improperly biases the effect of small cycles on crack growth. There are several ways to account for threshold effects, as follows.

— A conservative lower-bound estimate for $\Delta K_{\text{th}}$ is 2.2 MPa $(\text{m})^{0.5}$ [2.0 ksi $(\text{in.})^{0.5}$]. The applied $\Delta K$ as a function of applied stress cycle amplitude and incremental crack size can be calculated at each applied stress cycle and compared with $\Delta K_{\text{th}}$ to determine whether the crack would be expected to enlarge during that particular stress cycle. With a fixed $\Delta K_{\text{th}}$, the applied stress cycle amplitude that exceeds the threshold decreases as the crack enlarges. For example, a threshold of 2.2 MPa $(\text{m})^{0.5}$ [2.0 ksi $(\text{in.})^{0.5}$] used in API 579-1/ASME FFS-1 is not exceeded by stress cycle amplitudes smaller than 4 % to 8 % SMYS depending on grade and pipe size until the crack enlarges significantly.

— Select a default pressure cycle amplitude value below which pressure cycles in the operating pressure record are disregarded; e.g. 170 kPag (25 psig). This is likely to be well below the threshold where MOPs/MAOPs are high. A fixed pressure amplitude filter should not exceed 5 % of the maximum pressure cycle.

— Other approaches to accounting for threshold effects may be applied by the operator as deemed appropriate to the circumstances.

### 8.2.4 Establishing Starting Crack Size

#### 8.2.4.1 General

The starting crack size for any growth analysis should be the most severe crack, accounting for the hydraulic gradient, remaining after the last integrity assessment for cracks. This size (or sizes in the case of a hydrostatic test) is highly dependent on the parameters of the integrity assessment and can vary along a pipeline segment.

#### 8.2.4.2 Using Hydrostatic Testing

The family of sizes of cracks that could survive a hydrostatic pressure test can be determined using a suitable fracture mechanics relationship between crack size and failure stress level. Several models are available, as discussed in Section 7. When applying such models, it is critical to consider the potential range of material strength and toughness. These properties can be determined from mill test data where available. Where mill test data are not available, the values for mean, lower 5$^{th}$ percentile (L5), and upper 95$^{th}$ percentile (U95) strength levels reported in Annexes D and E may be used.



It is important to use suitably high values for strength and toughness when establishing the remaining crack sizes by hydrostatic testing since larger cracks can survive a test in stronger and tougher material, and larger cracks have a shorter time to failure than smaller cracks at a given growth rate. Assuming low strength and toughness values in this case would be nonconservative.

The sizes of cracks postulated to survive a hydrostatic test range from deep-and-short to shallow-and-long. The times to failure can vary significantly across this range, so several combinations of crack depths and lengths should be considered. The test segmentation, test pressures (elevation changes), and the hydraulic gradient should also be considered.

Whether a pipeline under pressure leaks or ruptures when it fails depends on the defect size. The relationship between flaw size and failure mode varies with the pipe attributes and pipe stress level at failure. Conceptually, where the critical pressure of the through-wall flaw that results when the surface defect pops through the pipe wall is greater than that of the surface defect that initiates the failure, the mode of failure will be a leak; where the critical pressure of the resulting through-wall flaw is less than that of the surface defect that initiates the failure, the mode of failure will be a rupture. In effect, defects that are axially short but relatively deep with respect to the pipe wall tend to leak when they fail, usually without releasing a great deal of stored energy and often producing a slow pressure loss; defects that are axially long but relatively shallow with respect to the pipe wall tend to rupture when they fail, usually releasing significant amount of stored energy and producing immediate and complete loss of pressure containment.

#### 8.2.4.3 Using ILI Data

A starting crack size is needed for calculating reassessment intervals. Methods to attain the crack size include ILI and ITD inspection. As Sections 11 and 14 discuss, the ILI and ITD inspection to determine the dimension of the crack can have varying degrees of accuracy. Operator experience with cracks on a specific vintage of pipe material is needed to establish an initial crack size from ILI data or ITD inspection. Crack sizes are estimated in a somewhat qualitative fashion taking into consideration the tolerances of the tool used as outlined in 11.6. It is critical that operators validate ILI results using excavation data and not default to ILI vendor-stated accuracies when establishing remaining flaw size.

Another approach to estimating the largest undetected crack remaining in the pipeline involves using statistical methods that take into account the information gained from the ILI tool, the confirmation ITD inspections, and estimates of the capabilities of the ILI tool performance in the field. This approach is described in 11.6.9.

## 8.3 Stress Corrosion Cracking and Corrosion Fatigue Growth

### 8.3.1 Combined Cyclic and Time-dependent Growth

The following function [Equation (5)] defines a coupled model for total crack growth as a summation of mechanical fatigue and SCC components:

$$\left.\frac{da}{dN}\right|_{\text{total}} = \left.\frac{da}{dN}\right|_{\text{fatigue}} + \frac{1}{f}\left.\frac{da}{dt}\right|_{\text{SCC}} \tag{5}$$

where

$\left.\frac{da}{dN}\right|_{\text{total}}$ is total crack growth as incremental crack growth length ($a$) per number of loading cycle ($N$) (inches per cycle in U.S. customary units);

$\left.\frac{da}{dN}\right|_{\text{fatigue}}$ is "Paris Law" mechanical fatigue [see 8.2.1, Equation (2)] as crack growth length ($a$) per number of loading cycle ($N$) (inches per cycle in U.S. customary units);



$\left.\frac{da}{dt}\right|_{\text{SCC}}$ is average crack growth rate over a loading cycle;

$f$ is the loading frequency.

An average crack growth rate approach independent of pressure cycling may be adequate with natural gas pipelines, provided future operating conditions remain relatively consistent with operation during the period of time for which an apparent representative average rate was developed. A coupled analysis considering both environmental cracking rate and fatigue should be used with liquid transmission pipelines. This requires knowledge of past crack sizes and pressure cycles in a trial-and-error process that reconciles past and present observations of crack sizes. Use of a simple average crack growth rate for predicting time to failure in a liquid pipeline can be nonconservative, depending on the conservatism of the input parameters and the period of growth.

### 8.3.2 Stress Corrosion Cracking Growth Rates

SCC growth rates likely introduce significant uncertainty in the calculation of a reassessment interval. Growth rates used for estimating the remaining life of SCC features should be conservative, yet realistic. All SCC on pipelines exhibit a distribution of growth rates that have minimum, average, and maximum values. When using a single growth rate, an understanding of where this value falls with respect to the distribution and the level of conservatism associated with this growth value is desirable. By analysis of SCC depths discovered within a region (a segment having common environment and loading), the SCC depth likely to remain in the field after assessment and remediation can be estimated. The $\Delta K$ for those assumed defects can then be compared to a threshold $\Delta K$ value appropriate to the environmental condition to identify the stage of growth.

SCC growth rates vary with the stage of growth, environmental factors that can vary seasonally, pipeline operating stress and temperature, residual stress, and interaction of the EAC mechanism with the coincident occurrence of stress cycles. Any of these factors could affect the passivation and reactivation of metal dissolution that occurs primarily for high pH SCC at the crack tip, thus affecting the rate of crack growth. A pipeline can operate for some period of time before conducive conditions develop (e.g. the coating wrinkles or disbonds) and some additional period of time before the cracking initiates. Crack growth accelerates initially and then slows to an approximately uniform average rate that can depend on environmental factors and duration or frequency of applied stresses. Then it accelerates again soon before failure. The flaw can enlarge to a size where mechanical fatigue contributes substantially to flaw growth.

ASME STP-PT-011 suggests that crack growth, once initiated, can be assumed to be approximately linear over time. This can be a reasonable simplification for natural gas transmission pipelines for which fatigue is only a small component to overall crack growth, but is unlikely to be accurate with liquid pipelines subject to frequent pressure cycles. Such an assumption also disregards the possible large changes in crack growth rate that could occur due to changes in environment or pipeline operation.

Recent research suggests that the tendency of SCC to either become dormant or to continue can depend on the pressure fluctuation characteristics of the pipe segment (see Beavers [27]). This research indicates that the magnitude of the individual pressure cycle (indicated by the R-ratio or ratio of minimum to maximum stress) and the duration and frequency of the stress cycle (strain rate) play a role in determining SCC growth. The contribution of cracking processes to growth likely shifts from SCC-governed at low rates or magnitudes of cyclic loading toward corrosion-fatigue or solely fatigue-governed as the cyclic activity increases. Tests have shown that the SCC-driven crack growth rate per load cycle varies inversely with the load cycle frequency. Figure 10, adapted from API 579-1/ASME FFS-1, suggests this effect in the context of environmental crack growth coupled with mechanical fatigue crack growth.

Operators are encouraged to evaluate the pressure cycling occurring on their pipeline before eliminating fatigue from consideration in terms of interacting with the SCC process. Moreover, even if coupling between fatigue crack growth and SCC is not a factor early in the SCC growth process, the effect of fatigue becomes greater as the SCC flaws grow deeper.



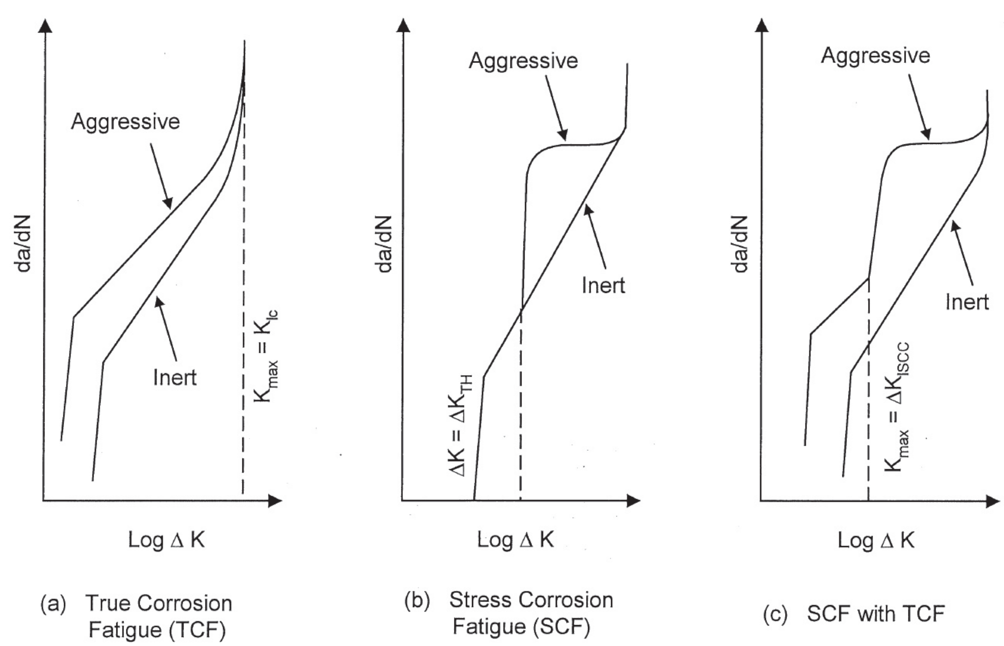



**Figure 10—Coupling of Mechanical Fatigue with Environmental Crack Growth Mechanisms**

Ideally, the growth rates should be derived from SCC features that are relevant to the primary concern (e.g. at the toe of the longitudinal seam where tape with a high dielectric value tents over a DSAW seam or within pipe body for ERW seam). Rates derived from field observations or failures should be given preference over estimates derived from other means. In the complete absence of field growth data, however, laboratory results may initially be used for selecting appropriate growth rate values, which should then be superseded once adequate data from field investigations are available. Refer to Annex A for further information about average growth rates derived from different approaches.

Four approaches to estimating crack growth rate might be considered, with the frequency and magnitude of cyclic loading being a key determinant.

— *Uniform Average Growth Rate*—The most probable stage of growth of SCC when it is observed in the field is the second stage, which is characterized by more or less steady growth (i.e. not the initiation stage and not the last stage, which is immediately before failure). Records from prior coating or corrosion inspections can give insights into the point in time when coating performance began to decline. If not, one must assume a point in time when that occurred. The growth rate is then the observed depth of the indications divided by the elapsed time from the initiation to the present. The present flaw size is presumed to reflect some effect of pressure cycles. Coupled with a fracture mechanics model for the critical defect size, the time to failure is the difference between the critical flaw depth and the current flaw depth divided by that growth rate. Such that the effects of pressure cycling are not specifically considered by this approach, where a range of times to failure are obtained from evaluating numerous flaws, preferential consideration should be given to those results with the shortest times to failure. Appropriate levels of conservatism should be incorporated in using this approach for a liquid pipeline.

— *Two-stage SCC and Fatigue Analyses*—With a pipeline subjected to significant frequency and/or amplitude of pressure cycles, once a SCC becomes sufficiently large, fatigue can take over as the primary mechanism for crack growth. A separate fatigue crack growth analysis may be performed in accordance with 6.2, either considering a range of initial crack depths representing the SCC at different stages or evaluating the full time history of crack depth from shallow initial size to failure. The depth at which fatigue governs occurs where the incremental crack growth rate due to fatigue exceeds the average crack growth rate for SCC. The net time to failure is then the time for SCC to enlarge the flaw to the point where fatigue takes over, plus the time for fatigue to enlarge the flaw to failure.



— *Coupled SCC and Fatigue Analysis*—Aggregate crack growth rates can change as stress cycling increases. Total crack growth rates would account for the effects of stress cycling.

— *Load Interaction Approach for Near-neutral pH SCC*—Pipelines are operated under variable pressure fluctuations. The models discussed above do not necessarily consider crack growth acceleration by both the stress-dependent and the time-dependent load interactions on crack growth during variable pressure fluctuations. The load interaction approach considers both the stress-dependent and the time-dependent load interactions on crack growth during variable pressure fluctuations and details are provided in Annex H.

### 8.3.3 Determining the Size of Possible Stress Corrosion Cracking

Both hydrostatic testing or use of ILI may be used to establish an initial flaw size as discussed in 8.2.4. Using a hydrostatic pressure test to estimate the size of potential SCC defects for establishing reassessment intervals is only useful where hoop stress due to internal pressure is the largest component of stress. Determining a remaining flaw size from hydrostatic testing does not adequately address circumferential cracking under the influence of longitudinal stresses.

Crack-detection ILI is capable of indicating the location and size of probable SCC. The ILI must be validated by investigative digs to verify tool performance within the vendor's claimed range of accuracy. The results of investigative digs can indicate systematic error or bias to be corrected for when evaluating the current size of uninvestigated indications. Incidental discoveries in the field that were not indicated by the ILI vendor report provides information about the size of unknown flaws that can exist. Refer to Section 11 for additional details.

## 8.4 Remaining Life

For Paris Law fatigue growth [see 8.2.1, Equation (2)], the remaining life is determined by the time required for an initially postulated flaw to reach a critical size and is a function of the pressure cycle amplitude and frequency. If using Miner's Rule [see 8.2.2, Equation (4)], the time it takes for the number of cycles for failure to occur is the remaining life, also referred to as “life fraction.” When life fraction equals 1, the fatigue life is consumed.

In the case of SCC, the starting flaw sizes plus the time-dependent portion of crack growth rate and the cycle-dependent portions are used to calculate the time to reach the critical flaw size and estimate the remaining life. In absence of ILI data, consideration should be given to varying aspect ratios.

Remaining life is the time it takes a crack to reach a critical size. The critical size can be defined as the size at which the crack would fail, taking into account historical operations, current operations, future operations, or some combination of these.

## 8.5 Reassessment Interval Determination

The remaining life calculations performed from either ILI or hydrostatic testing and the applicable growth model are used to determine the reassessment interval. An appropriate factor of safety should be applied to remaining life calculations, and the result is added to the date of the previous assessment. The factor of safety should consider the level(s) of conservatism applied to the remaining life calculation and also should take into account the risk associated with the pipeline. Consideration should also be given to the overall timeframe because very short calculated times to failure can be overly sensitive to input assumptions.

Aside from regulatory requirements, the reassessment needs to occur before any potential cracks reach a critical size, taking into account the uncertainties associated with tool technology and inputs to the remaining life calculations. The assessment method chosen needs to be able to detect or eliminate the size of cracks that have determined the interval.



# 9 Gathering, Reviewing, and Integrating Data

## 9.1 General Considerations

The approach to data gathering, reviewing, and integrating data is defined in API 1160, Section 6. The data list included herein provides those factors possibly relevant to the cracking threats covered in this document. The applicability of any particular data element depends on the cracking mechanism and spectrum of line- and site-specific considerations, as follows:

— manufacturer;

— material test reports;

— year of manufacture;

— type of seam (LF- or DC-ERW, HF-ERW, SSAW or DWAW, flash weld, lap weld) or seamless;

— pipe mill inspection procedures for seam cracks;

— heat treatment of the seam;

— cold expansion;

— plate or skelp formation process, such as continuous cast, ingot;

— MOP/MAOP;

— locations of pump stations, booster stations, and terminals;

— weld quality and inspection;

— coating installation method (over-the-ditch versus factory coating of pipe and field coating of joints);

— coating type;

— soil type (sand, silt, clay, rock);

— backfill practice;

— soil resistivity;

— depth of burial;

— terrain;

— type(s) of products transported, including liquids, two phase, gas;

— bulk flow velocity;

— detailed pressure histories;

— CP potentials;



— operating temperature range;

— pressure levels achieved in previous hydrostatic test and test failure history;

— anomaly lists from previous ILIs along with disposition of anomalies;

— field NDE results, including number of anomalies detected that were not identified by the ILI assessment process;

— results of any additional assessments such as close-interval pipe-to-soil potential surveys, direct current voltage gradient (DCVG) surveys;

— pipeline current surveys, soil resistivity surveys, direct visual inspections of the pipe and the coating, ROW;

— condition surveys, and depth-of-burial surveys;

— previous repair types and practices.

## 9.2 Threat Interaction

Beyond assessing the cracking threat in isolation, the operator should perform the applicable data integration in order to identify interaction with other threats. This analysis can range from identification of coincident features where the ILI assessments only identified and sized the separate features in isolation (e.g. cracks in corrosion) to the use of the presence of one feature as indicator of another (e.g. corrosion as an indication of disbonded coating).

# 10 Methods of Integrity Assessment

## 10.1 General

Determining the most appropriate method for the assessment of cracks should involve consideration of many factors, not the least of which is the configuration of the pipeline and whether ILI tools can be practically used. The following sections provide guidance on making this decision by considering the capabilities and limitations of the various approaches. One important consideration is the capability of a given method to detect flaws that enable an accurate assessment of the line integrity. Details regarding ILI and hydrostatic testing as means of integrity assessments can be found in Sections 11 and 12, respectively. Another method to assess a pipeline for one type of crack, SCC, is stress corrosion cracking direct assessment (SCCDA), which is presented in Section 13. This methodology does not provide as high a level of integrity assessment as ILI or hydrostatic testing.

## 10.2 In-line Inspection (ILI)

In-line Inspection (ILI) should be considered when the line segment specifics (such as diameter and wall thickness) and product type allow the use of a proven technology that can be demonstrated to sufficiently detect and characterize the identified cracking threat. In this context, "proven technology" means that the operator and/or the industry has experience that shows the specific ILI technology (or combination of technologies) can accurately detect the size and characterize the type of cracks thought to be present on the line segment. "Sufficiently" means there are adequate safety factors between the failure pressure of the remaining population of cracks (including known or suspected tool error) and those that could fail in service when appropriate crack growth is applied. "Accurately" means that the verified probability of detection (POD) and probability of identification (POI) of the ILI tool are within accepted industry standards and recommended practices.



Current industry experience indicates operators should first consider if ultrasonic tools for cracking applications are more appropriate. For operators with extensive experience using magnetic tools for crack detection on a line segment, those tools may be similarly appropriate for some crack morphologies. Magnetic tools can and should be also considered when ultrasonic tools are not feasible due to the pipeline physical and operational parameters. Magnetic tools should also be considered in addition to the use of ultrasonic tools when the POD of the ultrasonic tool is not sufficient to ensure integrity, for example, when weld trim makes detection of some seams cracks difficult. The operator should document the reasons why the selected ILI technology is sufficient.

ILI should also be considered in situations where hydrostatic testing cannot achieve the desired safety factors (reassessment interval) after completion. Example scenarios are when historic failure data suggest large pressure reversals (greater than 2 % of the test pressure) or elevation changes create too many test segments to practically implement.

An ILI assessment may be the only integrity assessment needed. Some circumstances that support the sole use of ILI include the following:

— any failure history on the line is well understood and can be managed with ILI assessments,

— the population of anomalies is all below the critical threshold to fail by hydrostatic test,

— the ILI results were adequately verified in the ditch or by other means,

— the pipeline has a documented hydrostatic test in accordance with regulatory requirements.

An operator can have additional circumstances that support the use of only ILI for crack assessment. ILI may still be the only integrity assessment needed as long as the operator documents the reasons why ILI is sufficient.

## 10.3 Hydrostatic Testing

Hydrostatic testing should be considered in the following conditions:

— the pipeline segment cannot be reasonably made piggable for the technology needed to find a known cracking threat type,

— the use of ILI does not achieve the desired safety factor due to anticipated detection and sizing capabilities,

— the desired reassessment interval cannot be achieved using ILI,

— ILI cannot identify critical sized flaws of the expected types,

— no ILI technology exists for the combination of pipeline parameters and cracking threats.

An operator can have additional circumstances that allow the use of only hydrostatic testing for crack assessment. The operator should document the reasons why hydrostatic testing is sufficient.

## 10.4 In-line Inspection and Hydrostatic Testing

### 10.4.1 General

Some circumstances or combination of circumstances suggest that a sufficient assessment for cracks can only be achieved by using multiple methods. A combination of both ILI and hydrostatic testing should be considered in the following conditions.



— The operator's experience with the selected ILI technology is limited and an applicable industry correlation dataset substantiating the tool performance is not available.

— Magnetic ILI tools are selected. The potential limitations of magnetic flux leakage (MFL) for detection and sizing of all cracks types is documented in 11.2. Hydrostatic testing, possibly of a segment or segments of a pipeline, could be needed to verify performance of ILI for POD and sizing accuracy when these cannot be practically validated by excavation.

— The operator is assisting in the development of new ILI technologies or seeking to demonstrate the reliability of a new technology and other existing technology, operator experience, history, cutouts, or other data are not available to confirm results.

### 10.4.2 Using Hydrostatic Testing to Supplement In-line Inspection

#### 10.4.2.1 General

As compared to detection of volumetric features such as metal loss, there can be a larger variability (lower POD/POI) for crack features. When the verification of crack features by excavation results does not sufficiently correlate with the ILI for detection or severity, hydrostatic testing, possibly of a segment or segments of a pipeline, could be required to verify the possible population of remaining cracks. Verification by hydrostatic test is demonstrated when a pipeline segment that could not be verified by excavation successfully passes a hydrostatic test without any failures. If failures occur, the testing of additional segments should be considered depending on the failure cause (i.e. could be unrelated to cracking). In some cases, an operator may elect to perform a verification hydrostatic test on only a portion of a line section inspected by ILI. When only a portion of the line is tested this way, the test section should be representative of the entire segment regarding crack type, growth mechanism, and pipe properties. If one hydrostatic test section is used to verify multiple ILI runs, then the operator must ensure that the critical characteristics of each ILI run (such as vendor, technology, and run media) are similar so that the results are not affected.

ILI can also be a useful tool to help complement a successful hydrostatic testing program. On pipelines with the potential to have a significant number of cracks that would fail a hydrostatic test, an ILI can help identify cracks for repair prior to hydrostatic testing. In this process of repairing, data should be collected to estimate the size of cracks that were identified by ILI and additional cracks at the same excavation site to provide data on the size of cracks that could remain after the hydrostatic test. Statistical analyses methods can then be used to determine the maximum remaining crack in the pipelines. This information is useful in pressure cycle fatigue calculations.

The appropriate timing between the two assessments is an important factor to be considered. Generally, when multiple methods are needed, the time between the assessments must allow adequate time for ILI data analysis, planning and scheduling of maintenance, excavation, and possible repair of indications, and configuring the pipeline and conducting the hydrostatic test. These tasks should be conducted as soon as reasonably practical.

Determining the order of assessments can have an important impact on the post-assessment safety factor (reassessment interval) and should consider a number of factors, particularly the size of cracks that each can detect.

#### 10.4.2.2 Assessing by Hydrostatic Testing First

When using both ILI and hydrostatic testing to assess for cracking, an operator should consider performing the hydrostatic test first when the following conditions are present.

— The pipeline does not have documented hydrotest.

— The outcome of an ILI assessment might not be sufficient to achieve the desired safety factor or reassessment interval due to potential inaccuracies of the ILI for the specific cracking threat.

— ILI cannot identify critical sized flaws of the expected types.



— It is desired to detect cracks with the ILI tool that survived or were created by the hydrotest or could have been grown by the hydrotest from a stable subcritical size to an unstable critical size that could start growing due to pressure cycling.

#### 10.4.2.3 Assessing by ILI First

When using both ILI and hydrostatic testing to assess for cracking, the operator should consider running the ILI tool first when:

— the operator is demonstrating capability of an ILI technology where the sizing capability and reliability of the ILI tool are actively being improved;

— the operator is documenting the performance of a technology, demonstrating all cracks that would fail a hydrostatic test were identified as critical;

— it is desired to identify and remediate flaws that may fail during the hydrotest;

— when assessing the capability of a new ILI technology.

### 10.4.3 Using In-line Inspection and Hydrostatic Testing in Successive Assessments

Multiple assessment methods can be useful to better understand the types and severity of threats. For some pipelines, one specific assessment method often establishes large safety factors and long reassessment intervals that can exceed allowable reassessment intervals. A second assessment method can be used in the interim to confirm the safety of the pipeline.

The following serves as just one example of how an operator may evaluate their pipeline. The example is not intended to supercede any regulatory requirements. If an operator determines a need to hydrostatically test a line every 20 years to maintain the desired safety margins, the operator could run ILI at an intermediate reassessment interval such as the 10-year interval. Representative scenarios after running an ILI tool include the following.

— If verification of ILI results confirms the tool performance and large safety factor, then the repeated hydrostatic testing could be delayed another 10 years by a second ILI.

— If no critical cracks are detected, and ILI technology is proven successful through excavation, the original 20-year reassessment interval for hydrotesting could be extended to 30 years.

— If no critical cracks are detected, but there is uncertainty with the performance of the ILI technology, the original 20-year reassessment interval is still valid.

Based on the results of the ILI and subsequent verification, the hydrostatic test schedule of 20 years should be reevaluated and adjusted accordingly. When ILI and hydrostatic testing are used alternately, it is necessary to account for the pressure cycles occurring during the test in determining any growth of ILI features.

## 11 In-line Inspection for Integrity Assessment

### 11.1 General

Pipeline companies use ILI technology to detect and assess the potential impact of various cracking threats and external nondestructive inspection in the ditch for collection of additional integrity information and for validation of inspection results. As established in API 1163, ILI is an efficient method to nondestructively inspect pipelines. API 1163 serves as an umbrella document to be used with and complement companion standards. NACE SP0102 and ASNT ILI-PQ all have been developed to enable service providers and pipeline operators to provide rigorous processes that consistently qualify the equipment, people, processes, and software utilized in the ILI industry. These documents provide general guidelines for application of inspection technology for all anomaly types that can threaten pipeline integrity.

ILI tools are designed to identify anomalies created by different threats; no one tool is capable of identifying features from all threats to pipeline integrity. For the specific pipeline to be inspected, the pipeline operator should understand the susceptibility of the pipeline to each type of cracking threat. Then, using the information in subsequent sections of this RP, an appropriate ILI tool or tools can be chosen to locate anomalies and provide information to aid in the integrity assessment of a particular pipeline segment.

While many ILI technologies have proven to be effective at locating and characterizing anomalies in pipelines, the pipeline operator should be aware of the limitations of any given ILI technology. The ILI vendor specifies the generalized performance of their ILI tool, including minimum detectable crack size, POD, and sizing accuracy. Actual tool performance will vary, either better or worse than the specification, depending on pipe properties and fabrication variables and variables associated with the specific inspection, including tool setup, product flow, and data analysis. Therefore, it is necessary to verify results for each pipeline inspection, and it is recommended to correlate data to previous ILI inspections. Similar to the limitations of hydrotesting discussed in Section 12, ILI detection and sizing may have limitations for specific crack geometries such as short, deep anomalies (that have inherently high failure pressures but can result in leaks).

Crack-detection ILI tools are evolving to meet the inspection challenges needed to ensure safe pipeline operation. There are two tool categories available for transmission pipelines: ultrasonic and magnetic. Ultrasonic tools detect discontinuities that exceed a minimum length and depth, even very tight cracks. Magnetic methods work best for crack anomalies with some volume of displaced metal; hence, the crack width or opening is an important parameter in detection along with length and depth. Other inspection technologies including eddy current, remote field eddy current, and radiography can detect cracks; however, no commercial tools are currently available for inspecting transmission pipelines at practical pigging speeds, conditions, and operational constraints with demonstrated crack detection and sizing capabilities comparable to appropriate ultrasonic or magnetic methods. The use of common ultrasonic and magnetic ILI technologies for cracks is presented next with additional details in Annex I.

The ILI inspection results can identify anomalies as potential cracks that are not cracks when inspected in the field (referred to as false calls). The analysis criteria used to identify features in the ILI log as features, anomalies, and potential cracks are a function of inspection variables such as velocity, product type, and line condition. If no false calls are discovered during validation, the analysis criteria used to identify features in the ILI log as potential cracks are likely too restrictive to provide assurance that cracks were not missed. The number of false identifications of potential cracks per distance is dependent on the pipeline variables such as surface roughness, inspection conditions such as velocity, and pipe manufacturing anomalies such as laminations, inclusions, and ERW weld trim.

## 11.2 In-line Inspection Tool Types

### 11.2.1 Ultrasonic

#### 11.2.1.1 General

The two categories of commonly used ultrasonic tools are classified by the methodology that the HF sound waves are coupled into the pipeline. The commercial tools that need a liquid medium between the sound generator and the pipe are referred to as liquid-coupled angle beam ultrasonic tools. The second method is an electromagnetic coupling method that directly produces the HF sound in the pipe. These are referred to as electromagnetic acoustic transducer (EMAT) tools and can work in either natural gas or liquid pipelines.

#### 11.2.1.2 Liquid-coupled Angle Beam Ultrasonic Testing



Angle beam ultrasonic inspection methods with sound wave frequencies on the order of a few megahertz generated by piezoelectric transducers are commonly used in many industries for detecting cracks in metals. Implementations for ILI became commercial in the mid-1990s. These systems require the pipeline to contain liquid media for coupling the ultrasound from the transducer into the pipe; this complicates the utilization of this technology for natural gas pipelines.

— *Identification of Anomalies*—This method has been used for identifying pipe body cracks such as SCC with good success. Identification errors include non-cracks identified as cracks (false calls) and cracks identified as other indication types. Surface breaking laminations can be identified as cracks. Cracks behind laminations might also be shielded and cannot be detected nor identified with this technology. Corrosion anomalies complicate analysis, with areas of metal loss corrosion either obscuring cracks making them difficult to identify or producing an indication that is falsely identified as a crack. The typical minimum depth of crack that can be detected and identified in vendor specifications is 1 mm (0.040 in.) for cracks longer than 25 mm to 30 mm (1 in. to 1.2 in.) as long as inspection variables such as ILI tool velocity and line condition are within ILI tool specification.

  Common seam weld anomalies also have the potential to be detected using ultrasonic methods, including anomalies such as lack-of-fusion (cold welds) and HAZ anomalies, such as hook cracks. Ultrasonic methods are not significantly influenced by the extent of the crack opening. For seam weld inspection, these methods are sensitive to natural fabrication variations associated with the manufacturing process such as weld trim and upset variations, as well as inclusions and laminations. Many ERW welds are trimmed flush to the pipe circumference. When there is excess material (under-trim) or extra material is removed (over-trim), the ultrasonic energy can be misdirected as it enters the pipe. Over- and under-trim conditions can also cause signals that are distinguished from crack signal through analysis rules. Analysis rules are used to identify cracks in poorly trimmed pipe while not calling a trim variation a crack. While the analysis rules for trim variation work most of the time, a well-trimmed ERW weld is more reliably assessed. Some of the same steel plate issues, such as impurity segregation that lead to hook cracks, also complicate the detection and sizing analysis. The analysis methods are not always successful in identifying the crack and dismissing benign anomalies such as contact marks and trim variation. The percentage of unreported or misclassified cracks in the analysis process and also the percentage of geometric features identified as cracks (false calls) are strongly dependent on the manufacturing of the steel and pipe fabrication process. Therefore, for cracks in the long seam, the typical crack depth threshold of detection in many vendor specifications increases to 2 mm (0.080 in.) as compared to cracks in the pipe body, but the length threshold is generally the same at 25 mm to 30 mm (1 in. to 1.2 in.) with qualifying remarks on velocity.

— *Depth Sizing*—The depth of crack-like features historically has been provided in bins, such as less than 1 mm, 1 mm to 2 mm, 2 mm to 4 mm, or greater than 4 mm (less than 0.040 in., 0.040 in. to 0.080 in., 0.080 in. to 0.160 in., or greater than 0.160 in.). This technology reaches signal saturation at approximately 4 mm (0.160 in.), such that depths beyond that point cannot be further delineated. Analysis methods are improving with some systems providing crack depth measurements as a percentage of wall thickness or as a discrete depth. Some systems are reporting crack profiles. Quantifying tolerance with an associated certainty and confidence will require more field verification data. Verification methods such as ITD or destructive assessment of pipes with cracks can be used to refine results. The sizing is most accurate for purely radial cracks such as typical SCC. Some inspection results have shown absolute depth sizing of cracks can have inaccuracies, but the ultrasonic methods can typically determine the relative size of cracks throughout a pipeline.

— *Product Influences*—Precise calibration of the product sound properties is important for an accurate crack depth determination. See 11.3.2 for additional information.

— *Sensor Configuration*—The transducers are angled in both the clockwise (CW) and counterclockwise (CCW) direction. The sensor spacing around the circumference is fixed, typically on the order of 10 mm (0.4 in.). The sound beams of neighboring sensors overlap enabling 100 % coverage. See 11.1.1.2 for additional comments on sensor pitch.

— *Use in Natural Gas Pipelines*—For natural gas pipelines, the liquid-coupled technology is implemented by batching, defined as the process of filling part of the pipeline with liquid. The liquid batch is contained by pigs with sealing cups, typically a pair, before and after the ILI tool. The batching liquid is chosen to be compatible with pipeline operations and is often diesel or fuel oil. The amount of liquid and, therefore, the length of the batch are dependent on pipeline configuration factors such as offtakes and valve types as well as internal pipe conditions; all offtakes should be closed. While difficulties have been reported, batching has been successfully used. Reported problems include speed excursions, local loss of coupling, and complete loss of couplant before the end of the run. Proper selection of liquids along with proper back pressure control normally reduces speed excursions, given there is enough liquid in the batch.



— *Angled Cracks*—For the highest POD and most accurate sizing, crack length should be aligned axially and the depth aligned radially with small angular deviations impacting results. For detection of axial cracks, specifications indicate detection is possible when the length is nearly axial, with angles up to 10° to 20° depending on tool type, and the depth is radial, with angles up to 45°, though operator experience indicates problems occur when angles exceed half these values. For accurate depth measurement, this method is sensitive to these angles as degradation in sizing accuracy can begin at a few degrees. Branching and hooking also influence the depth measurement.

#### 11.2.1.3 Phased Array ILI

Phased array is a liquid-coupled angle beam technique; while the sensors are very different, the goal of producing a 45° shear wave in the pipe is the same. Building on medical imaging technology, each sensor head contains hundreds of smaller piezoelectric elements. Using electronic timing, the beam can be steered to the proper angle. The flexibility of phased array enables many configurations; e.g. a smaller sensor spacing around the circumference can be achieved (less than half the ultrasound system described previously), but the cost is a reduction in tool speed. Also, normal beam waves for wall thickness measurement and lamination detection can be generated by firing all the elements simultaneously.

There are many similarities between the phased array and the liquid-coupled angle beam ultrasonic systems. For ultrasonic systems, precise calibration of the product sound properties is important for an accurate inspection, and vendors may ask for a sample of the product. However, for phased array systems, product changes would require changing the electronic timing used to set the beam angle rather than a sensor reconfiguration.

#### 11.2.1.4 Electromagnetic Acoustic Transducer (EMAT)

Electromagnetic Acoustic Transducer (EMAT) based ILI is an ultrasonic NDE method for pipelines that does not require the liquid coupling needed for classical ultrasonic piezo ceramic-based probes used for crack detection and wall measurement. This evolving technology was first prototyped for pipelines in the 1980s, and functional commercial systems became available in 2003. Ultrasonic waves are generated directly in the pipe wall. A coil induces eddy currents in the presence of a magnetic field, resulting in oscillating Lorentz or magnetostrictive forces that excite ultrasound waves in the metal.

These sensors can be configured to produce different ultrasound modes/types and frequencies. A variety of different geometries and arrangements allow propagation in almost any direction including around the circumference of the pipe. Compared to classical ultrasonic systems, EMATs have significant differences, which lead to advantages and disadvantages. Unlike MFL, but like liquid coupled angle beam ultrasonic systems, EMAT methods are not significantly influenced by the crack opening. However, sharp edges as in steep wall corrosion can be incorrectly identified as cracks. Combined defects make discrimination more difficult as in every technology; therefore, EMAT ILI results are often paired with metal loss inspection technologies, preferably a circumferential MFL to further increase the POI for cracks. A primary difference from liquid coupled ultrasonic systems is that the frequency of the EMATs is an order of magnitude lower. The lower frequency translates to a longer wavelength, which adversely influences resolution and therefore minimum defect specifications. EMATs seem to provide sufficient information to discriminate between crack indications and upset/trim associated with the fabrication of the weld, as well as inclusions and laminations in the base metal. However, EMATs are sensitive to the exterior coating adherence. Depending on the EMAT implementation, this can be a problem or an attribute. For some EMAT implementations, the absorbsion of the ultrasonic wave by some coatings can make cracks hard to detect. However, some EMAT implementations can discriminate between coating types or detect coating disbondment or missing coating.



Also, EMAT tools can operate in both pulse echo and thru-transmission mode. In pulse echo mode, the same sensor sends and receives the ultrasonic wave; a crack or anomaly acts as a reflector of the ultrasonic energy and returns the ultrasonic wave. In through-transmission mode, one sensor sends the ultrasonic wave and another receives; a crack or anomaly interrupts or limits the propagation of the ultrasonic wave from one sensor to another. The depth sizing is often based on various characteristics of the signal received from both the pulse-echo and thru-transmission modes, whereas the classical liquid coupled ultrasound systems (including todays ILI tools based on PAUT) mostly base their sizing on signal amplitude. The size of EMAT transducers currently challenges implementations for pipe smaller than about DN 300 (12 in. diameter).

Due to the variety of possible EMAT implementations, inspection tools from different ILI vendors can have more performance differences, attributes, and constraints than MFL or ultrasonic testing (UT) systems from different ILI vendors.

### 11.2.2 Magnetic Flux Leakage (MFL)

Magnetic Flux Leakage (MFL) systems, regardless of configuration, can be designed to remain functional in an abusive pipeline environment for long distances at product flow speeds. The source of inspection energy (permanent magnets) requires no energy during an inspection, and the sensors and data recorders require reasonably low power to operate. The magnetic flux naturally enters the pipe and distributes evenly to produce a full volumetric inspection.

The MFL inspection technology is often described as both a direct and indirect measurement technology. For example, the common application for metal loss directly detects metal loss but indirectly measures the depth. The circumferential flux leakage methods systems have the potential to directly detect axial cracks and also indirectly detect cracks by noting changes in the magnetic condition that could be associated with presence of crack. Detection is best with the field orthogonal to the crack, i.e. a circumferential magnetic field for axial cracking. The signal strength is also directly related to the width of the crack; therefore, opening plays an important role in detecting these anomalies. Surface also plays an important role. The MFL that can be measured by an ILI tool is stronger at the crack opening as compared to flux leakage from a crack tip that is below the surface. OD and subsurface cracks can be detected, and the leakage level is greater the closer the crack tip is to the ID surface. In general, when ID and OD cracks are equally likely, pipeline operators should review results to ensure an appropriate number of ID and OD cracks are identified. Crack detecting and sizing specification is difficult to quantify and can vary significantly. The detection of small, tight cracks can be demonstrated, but this may be the result of indirect detection. However, while difficult to quantify, indirect detection of cracks can be very useful in a crack management program. Many vendor specifications list a range of minimum crack opening of 0.1 to 0.2 mm (0.004 in. to 0.008 in.) for detection without depth sizing, and depth sizing can be performed to some accuracy for cracks greater than of 1 mm (0.039 in.) wide. In general, as compared to ultrasonic tools, the specified detection threshold is typically larger and less precise in depth measurements. However, circumferential magnetic tools may measure physical properties that could expose cracks.

Circumferential magnetic flux leakage (CMFL) magnetizers apply the magnetic field in the hoop direction of the pipe, transverse to the more typical axial field used in the metal loss MFL systems. The ILI tools have magnets in pairs, and arrays of the sensors between the poles around the pipe circumference are used to record defect signals. These tools are typically longer than typical axial field MFL ILI tools.

Other implementations of MFL for cracking use a single helically shaped magnetizer. Some implementations use multiple short magnets; each magnet pair is offset around the circumference. Another implementation uses pole spacing similar to the common two-module CMFL tool, with magnets indexed around the circumference in the form of a helix. The overall tool length of helical designs is shorter than CMFL tools. The magnetization direction is not completely circumferential but is a combination of the axial and circumferential flux leakage response. The specified performance of these helical implementations is comparable to CMFL systems; the observed performance is less known for this emerging technology.

### 11.2.3 Tools for Circumferential Cracking

#### 11.2.3.1 General



While a majority of cracks in pipeline are axial, either in the pipe body or seam weld, other crack orientations are possible. Circumferential cracks are possible in girth weld or in the pipe body when the pipe is under axial or bending loads. Both ultrasonic and magnetic tools are commercially available to detect circumferentially oriented crack-like anomalies.

#### 11.2.3.2 Reconfigured Liquid-coupled Angle Beam Ultrasonic

ILI tools with liquid-coupled angle beam ultrasonic inspection can be reconfigured for detection of circumferential cracks. The individual sensors in the sensor carrier would be angled to produce 45° ultrasonic angle shear waves with respect to the pipe axis. Since only the orientation is changed, the specification for detection threshold [1 mm (0.040 in.) in base material and 2 mm (0.080 in.) in weld] and sizing capability [less than 1 mm, 1 mm to 2 mm, 2 mm to 4 mm, greater than 4 mm (less than 0.040 in., 0.040 in. to 0.080 in., 0.080 in. to 0.160 in., or greater than 0.160 in.)] is nominally similar to the more commonly used axial crack assessment systems. One exception is tool speed; at speeds above the maximum specified by inspection provider, the distance between measurements increases. If this distance is too large, circumferential cracks can be skipped over by inadequate sampling. The miles of pipeline inspected and number of cracks found are orders of magnitude less, so the experience base needed to refine the accuracy of these tools is limited. Detection of cracks in girth welds fabricated with an automated process is typically better than manually welded pipes. One application of the reconfigured liquid-coupled angle beam ultrasonic method is the detection of cracks in the HAZ of Type B sleeves described in 15.5). While technically feasible, inspection vendors have limited experience with this application.

#### 11.2.3.3 Axial MFL for Circumferential Cracking

Axial MFL tools, the common implementation used to detect and size corrosion, can be used to detect circumferential cracks. The width of the crack opening plays an important role in detecting these anomalies. Since the cracks produce a short flux leakage signal, some inspection vendors acquire data at shorter intervals along the pipe; e.g. a typical axial distance between successive readings is 2.5 mm (0.1 in.) for MFL tools configured to assess corrosion. For circumferential crack detection, the tools can be configured to acquire data every 1.25 mm (0.05 in.). This would double the amount of data, and the tool speed would have to be more closely controlled since excessive speed could prevent sampling at these fine increments. Operators reported better success with tools that measure the axial and radial component of the magnetic fields—two of the three components in a triaxial sensor. Smaller cracks can be detected in the pipe body than in the girth weld. For girth welds, there are three sources of signals:

— the amount of weld material;

— sensor liftoff caused by the root pass penetrating beyond the ID of the pipe;

— a crack signal itself, including crack opening, can influence results.

These complex signals require careful analysis to detect girth weld cracks.

While many inspection vendors have reported detecting circumferential cracks due to overbend and girth weld cracks, the method is most reliable for finding cracks that have a visible opening with more than a few inches of circumferential extent. Most inspection vendors do not provide a specification for detection of circumferential cracking. Since the configuration is similar, the specification for CMFL for axial cracks is generally applicable for axial MFL for circumferential cracks.

## 11.3 ILI Tool Utilization Considerations

### 11.3.1 General

Pipeline design factors (such as diameter, wall thickness, and pipeline features) and operational factors (such as product pressure and flow rate) can influence the application of some technologies. This section provides guidelines for the application of the various ILI tools.



### 11.3.2 Product

Ultrasonic tools need a liquid product to transport the HF sound waves from the sensor to the pipe and back. The type of product does affect performance; some preferred products are diesel, refined oils, and light crude. For heavy crude lines, light crude sometimes is batched to launch and propel the tool when available. Pipelines that transport lighter products, such as propane, require extra consideration as runs can fail due to low pressure, variable product density based on the pressure along the pipeline, and other factors that reduce the energy that is transmitted into the pipe and alter the angle the sound enters the pipe from the necessary 45°. Operators may consider product substitutions and operational changes to accommodate inspection tool parameters to achieve more thorough and accurate inspections. As a guideline, potential inaccuracies due to the product and substitution should be discussed with the ILI service provider when running in a product with an API gravity greater than 45.

Because even slight changes in product properties can impact tool performance, operators should pay special attention to product movement schedules on multiproduct lines or product densities that appreciably change at the pipeline start/end points. Many vendors ask for a sample of the product or check the sound velocity and attenuation on site. Product changes need to be anticipated as a recalibration could require rebuilding the sensor carrier. This includes product temperature, as that can also affect calibration. When pipeline operators do not have experience with a particular product, delays can be reduced by ensuring product impacts and changes are properly addressed with the inspection vendor.

The product type is technically not a consideration for the sensors used by EMAT and flux leakage tools. However, for gas inspection with these tools, the product pressure can be an issue for pipelines running lower pressures, typically below 2000 kPa to 4000 kPa (300 psi to 600 psi), especially for EMAT tools. At lower pressures, the speed excursions within a joint or a few joints of pipe can occur; increased pressure reduces the severity of velocity excursions. For CMFL, higher pressures could open OD cracks for better detection, but it is unclear whether a measurable difference would be made.

### 11.3.3 Diameter and Wall Thickness

Angle beam ultrasonic tools are available for pipeline diameters ranging from DN 150 to DN 1200 (6 in. to 48 in.). The performance specifications for these tools are generally equivalent over the range of diameters. Some pipeline owners report some performance degradation for diameters less than DN 250 to DN 300 (10 in. to 12 in.). Below this level, pipe curvature can start to affect beam angle with the angle of incidence for the 1.5 skip signal diverting from the optimal 45. The result is that the return peak signal amplitude will not be at the sensing transducer, making detection and sizing more difficult and typically less accurate. Also, operators report reduced detection, identification, and sizing below about 6 mm (0.250 in.) wall thickness because the sensor size is greater than the wall thickness and the entire wall is flooded by sound. EMAT tools are available for pipeline diameters ranging from DN 300 (12 in.) to over DN 1200 (48 in.). Tools for smaller diameters are still emerging. However, the sound generated by an EMAT is a function of the size of the sensor, and scaling the sensors for smaller diameters can affect the relative performance of these tools.

Phased array ultrasonic ILI tools are also newer systems and are available for larger diameter pipes. Phased array ILI tool limits are similar to signal probe angle beam UT; however, there is less operator experience with these newer tools.

Also, CMFL tools are available for pipeline diameters ranging from DN 150 (6 in.) to over DN 1200 (48 in.). For the more established CMFL systems, the tools have diameter ranges over which the configurations are similar. The different configurations are needed to effectively magnetize the pipe. CMFL tools for pipe less than DN 500 (20 in.) typically have two poles: for pipe from DN 500 (20 in.) up to the DN 750 to DN 900 (30 in. to 36 in.) range, four poles are used. Other configurations are often used for the largest diameter pipelines. The extra poles are needed to provide sufficient magnetic flux to create strong flux leakage signals. While the specifications for these systems are nominally the same across all diameters, actual performance can vary at the transition for various configurations. Heavier wall pipes can limit the capability of CMFL tools because the strength of the flux leakage at the ID from an OD crack is dependent on the distance from the crack tip to the ID surface. In other words, the flux leakage at the ID for a 50 % deep OD crack in a heavy wall pipe probably is not as strong at the same depth and crack in a thin wall pipe. CMFL systems are better at detecting cracks in pipe less than or equal to a quarter-inch and poorer at detecting cracks in pipe with wall thicknesses greater than a half-inch. Wall thickness in a transition zone between a quarter-inch and a half-inch depends on the combination of factors including diameter and inspection velocity. Magnetizers for smaller diameter pipes (16 in. or less) and heavier wall thicknesses in the transition zone could supply insufficient flux to produce a detectable signal. Diameter is a factor because magnetizer design variables that enable the tool to pass dents and obstructions limit the space available for magnets in smaller ILI tools. Some operators report reduced performance for smaller diameter tools. Operators may consider extra verification digs to better understand detection capability and sizing accuracy. For inspection runs with both heavy and thin wall pipe, the CMFL tool should be set to assess the pipe with the highest potential for cracking and growth. In most cases, this will be the thinner pipe.



The helical MFL systems are more common in smaller diameters down to DN 150 (6 in.). Operators have less experience with these newer tools; therefore, the performance variation is not well documented. Operators may consider extra verification digs to understand detection capability and sizing accuracy.

### 11.3.4 Cleanliness

Pipeline cleanliness is a very important factor for liquid-coupled ultrasonic systems. Debris, air bubbles, and wax deposits can degrade the signal responses.

Pipeline cleanliness is important for EMAT sensors since the sensors should ride as close as possible to the pipe for good electromagnetic coupling of energy into the pipe.

For flux leakage systems, the level of cleanliness is the least restrictive, though debris and wax can still build up and cause either the magnetizer or the sensors to lift off the pipe surface.

### 11.3.5 Tool Speed

In general, ILI speeds for crack tools are slower and more controlled than speeds for the more common flux leakage tools used for corrosion. For all crack inspections, operators should plan pipeline operations to achieve consistent velocity control near the optimal inspection speed. Operators should consider selecting a flow velocity below the maximum speed, to allow for increases in tools speed after the tool slows and works past bore restrictions. Speed excursions above the maximum speed could result in reduced inspection performance. Speed control using product bypass should be considered in the ILI planning stages.

For angle beam ultrasonic tools, velocity can be a factor for inspection. If the specified speed is exceeded, the distance between successive data points along the pipeline increases and the minimum detectable crack length increases. As data acquisition systems are getting faster, the velocity restriction becomes less of an issue for updated ILI tools. ILI tool speed typically does not significantly affect the ultrasonic inspection energy.

For EMAT tools, velocity can affect the inspection energy and add noise to the signals recorded from anomalies in the pipe for speeds that exceed the specified maximum and during abrupt speed changes. Since speed control is more challenging in gas pipelines as compared to liquid lines and EMAT tools can have a significant magnetic drag compared to other ILI tools, speed variation can occur in gas pipelines. Performance can be compromised in lower pressure gas pipelines when the pipeline has significant protrusions such as girth welds and when the pipe transitions to and from thicker wall pipe.

For magnetic tools, velocity affects both the inspection energy by lowering the magnetic field and the flux leakage at defects. Noise due to sensor ride can also influence accurate detection of anomalies. With magnetization in the circumferential directions, the changes in magnetization level and flux leakage due to velocity are detectable at lower speeds, often less than 8 km/h (5 mph), than that detected with the axial MFL configuration used to assess corrosion.



### 11.3.6 Seam Weld Configurations

The separation of ILI indications that result from the natural variation of the seam manufacturing process from actual seam cracks that represent an integrity threat can be challenging. Some seam manufacturing processes are more prone to, but do not always, influence the ability to detect cracks; e.g. a well-trimmed ERW seam weld can be difficult to detect and will not influence detection and sizing capability. However, a local change in trim can be incorrectly identified as a crack rather than a natural variation in the manufacturing process seam weld. The significance of the weld is dependent on the individual inspection technology.

Many seam weld configurations produce benign weld signals that mix with potential crack signals. For ultrasonic systems, many changes at the seam produce signals, especially the natural flash in FW pipe, caps and roots on SSAW and DSAW welds, and ERW over- or under-trim. The separation of the seam weld indications from crack anomaly signals is a labor-intensive process that can decrease POD of seam cracks. On flux leakage tools, the square-notch shape of a flash weld pipe, the extra weld material of SSAW and DSAW welds, and ERW under-trim have two effects. First, the added metal changes the flux patterns. Second, the flux leakage sensor head riding on the weld is typically much wider than the weld; therefore, some of the sensors in the sensor head are lifted off from the pipe.

### 11.3.7 Product Temperature

Product temperature is a consideration in tool selection. Ultrasonic tools are sensitive to product temperature because the high voltage ultrasonic pulse generator produces heat that must be dissipated. The maximum temperature specification for various ultrasonic ILI tools range from 50 °C to 70 °C (122 °F to 158 °F). The upper value is the maximum temperature for commercial electronics; however, operating at this value for extended periods may be problematic since it can be difficult to dissipate heat that builds up in the pressure vessel that houses the electronics.

### 11.3.8 Coating Condition

Because of the nature of their wave propagation, EMAT tools are affected by coating condition. Heavier viscous coatings absorb the sound energy as it propagates around the circumference. In contrast, disbonded or missing coating does not reduce the propagating sound energy. Some EMAT tools can provide an assessment of coating condition. The ability of an EMAT ILI tool assess coating quality can be an indication of this sensitivity of the ILI tool to this inspection variable.

Angle beam ultrasonic and flux leakage tools are not affected by coating condition.

### 11.3.9 Interaction with Other Anomalies

Corrosion and other anomalies can affect ILI crack detection. For corrosion mixed with SCC, the crack and corrosion signals tend to mix; the effect is dependent on the corrosion morphologies. For lines with corrosion near cracks, it is often advantageous to integrate the results of a metal loss inspection with a crack assessment in parallel.

Dents also affect all crack detection tools. For liquid-coupled angle beam ultrasonic tools, the dent changes the angle needed to generate the 45° shear wave, so any energy that enters the pipe and reflects from a crack would most likely not return to the sending sensor for detection, identification, and sizing. For EMAT and MFL systems, dents cause separation between the magnets and/or sensors. Magnetizer separation reduces the energy that enters the pipe. Sensor separation causes both loss of signal and complex signals. Inspection results that identify a crack in a dent should be investigated. However, the presence of a dent results in reduced probability for crack detection below the vendor-published value.

## 11.4 Capabilities of In-line Inspection Tools for Axial Cracks



The detection and sizing capabilities of ILI tools are shown in Table 1 for axial cracks. Annex J further elaborates on the applicability of the ILI technologies to the axial cracking mechanisms.

## 11.5 Verification of ILI Results

### 11.5.1 General

Crack tools have not yet demonstrated the consistent reliability and accuracy of traditional metal-loss tools; therefore, a more thorough approach to determining ILI tool performance in terms of POD and identification of specific crack types, as well as sizing against results in the inspection report, is needed. A verification approach might include examination of the most significant potential crack anomalies as called by the ILI vendor. Verification might also include a sampling of less-significant potential crack anomalies and other anomaly types. Verification could also include more extensive excavation using ITD examination of the pipe on either side of the identified anomalies to check for unreported anomalies. The extent of pipe that can be practically examined varies with field conditions; the operator could consider examining on the order of 3 m to 6 m (10 ft to 20 ft) upstream and downstream or the entire joint (depending on the threat). Verifying can be a lengthy process that can pose an issue to achieving regulatory compliance; however, it should be done to maximize results. For guidance on how many of each indication type to use in the verification process, see 11.7.

An operator should follow the procedures outlined in API 1163 to verify that crack ILI data meet the vendor's specifications. However, the nature of crack-like features and current limitations for ITD inspection techniques present unique challenges in verifying crack ILI data. An operator may be challenged to confirm that POI specifications are met due to current ITD technology being unable to consistently classify defects accurately, particularly in the longitudinal seam. Similarly, confirmation of the POD can be challenging for midwall- or ID-connected defects as they cannot be seen visually and true detection will be contingent upon the field angle beam UT inspection. Additionally, the measurement error for most ITD NDE methods can fail to provide reliable sizing confirmation for relatively small sample sizes. It is critical that an operator fully understand this error and how it varies with inspection technology, operator skill, and situational circumstances. An operator should consider destructive methods of verifying identification and sizing, including grinding (when possible) or cutout, as part of their ILI validation procedures when

**Table 1—In-line Inspection Tools and Capabilities for Axial Cracks**

| Type of Axial Crack | Location | Magnetic | | Ultrasonic | |
|---|---|---|---|---|---|
| | | Two-module Magnetizer Circumferential Magnetic Flux Leakage or TFI | Continuous Magnetizer Helical or Spiral | Liquid-coupled Angle Beam Ultrasonic Testing | Electromagnetic Ultrasonic Testing (Most Products) |
| Stress corrosion cracking | Base pipe | Conditional D | Conditional D | S | S |
| Fatigue cracks | Pipe and seam | Conditional D | Conditional D | S | S |
| Fatigue cracks in dents | Base metal | Conditional D | Conditional D | Conditional D<br>Conditional S | Conditional D<br>Conditional S |
| Pipe mismatch | Seam weld | D | D | D | D |
| Hook cracks | Seam weld | Conditional D<br>Conditional S | Conditional D<br>Conditional S | Conditional S | D<br>Conditional S |
| Fatigue enlargement of hook cracks | Seam weld | — | — | Conditional S of the total depth | Conditional S of the total depth |
| Lack-of-fusion | Seam weld | Conditional D | Conditional D | S | S |
| Penetrators | Seam weld | — | — | Conditional D | Conditional D |
| Stitching | Seam weld | Conditional D | Conditional D | Conditional D<br>Conditional S | Conditional D<br>Conditional S |

NOTE 1 D is detection capability as specified by vendor with limited or no sizing capability.

NOTE 2 S is detection capability with sizing capability specified by vendor.

NOTE 3 Conditional D or Conditional S indicates that a qualification on ability to detect or detect and size may be possible in certain conditions or may be achieved outside of typical vendor specifications.



certain levels of precision are needed. Furthermore, the basic competency of angle beam UT operators may be established through performance qualification exams including internal company specific requirements, technical organization such as ASME, ASNT, and API QUTE (Qualification of UT Examiner) detection and sizing programs.

### 11.5.2 Comparison to Previous Crack ILI Data

If previously verified crack ILI data are available for the pipeline segment, an operator may correlate the two datasets to gauge the accuracy of the new dataset. Where there are potentially time-dependent factors that can contribute to defect growth, this method should not provide sole verification that the new ILI data are accurate or overcalled. However, this method can be used to reject new data that are consistently under-called in comparison to previously verified data prior to conducting investigations. When comparing to previous runs, operators should evaluate applicability of data associated with previously field assessed features that possibly have been partially ground out prior to repair.

### 11.5.3 Calibration Features

Some operators install manufactured notch-like features on the segment of pipeline to be inspected using a machining method such as electrical discharge machining (EDM). These features provide known dimensions against which crack ILI data can be compared against. An operator should use caution in using these results alone to verify tool performance; e.g. CMFL systems can detect EDM notches while miss cracks of the same length and depth because of the comparatively large width of the notch [typically 0.229 mm (0.009 in.)]. The simple dimensions of these notch-like features do not fully replicate the more complex geometries of crack-like features, particularly when intergranular environmentally assisted cracking (near-neutral pH SCC) is expected. However, this method can be used to reject tool performance for POD and/or sizing certainty if the vendor fails to accurately report and size the known features within their specifications. Additionally, operators should consider the possibility of future fatigue growth when designing and installing features on an assessment segment. Alternatively, the manufactured feature can be repaired with a sleeve or other repair or installed on a flanged spool that can be conveniently removed for use at a later date (or on additional segments).

Prior to conducting a crack ILI, an operator may elect to verify the performance capability of the tool using a pull test. If the operator has crack features that have been removed from service, a pull test could be performed. However, actual test conditions can be difficult to replicate. MFL systems are well suited for a pull test since the major configuration constraint is pipe length as it is best to keep anomalies a pipe diameter or two from a girth weld. EMAT systems can also be pull tested; however, replication of the original coating type is needed for absolute determination of performance since these tools have varying sensitivity to coating condition. Liquid-coupled tools are the most challenging to test in a pull rig environment as a liquid medium is required; however, this has been accomplished for smaller diameter tools using large tanks. Test loops have also been built; these typically use a simple medium such as water, which does not address sensor angle and medium attenuation variables.

#### 11.5.4 In-the-Ditch NDE

In-the-ditch (ITD) technologies and methodologies, while based on common ultrasonic and magnetic principles, can be more varied in their method of application and the results can be more inspection provider dependent than inspection by in-line tools. Annex K further elaborates on ITD technologies to assess crack-like features. Magnetic particle inspection (MPI) can be utilized ITD to verify lengths of external surface-breaking defects. For verifying length of internal or midwall features and depth of all features, an operator must consider the measurement error of NDE methods, which can necessitate a large sample of correlated features to reach an acceptable level of confidence. Limitations of currently available NDE technology in classifying crack-like features in the longitudinal seam can prevent an operator from determining if time-dependent defects are present based solely on NDE results.



#### 11.5.5 In-the-Ditch Destructive Measurement

In-the-ditch destructive measurement in the form of progressively grinding crack-like (and crack field) features to removal can be an effective method of verifying shallower depth dimensions of features located in the pipe body. Guidelines for repair by grinding can be found in 14.2.

#### 11.5.6 Laboratory NDE and Destructive Testing

An operator should consider periodically obtaining cutout samples of crack-like features to verify the performance of crack ILI tools, especially when results compare unfavorably with proven, accurate ITD NDE. Advanced NDE methods can be used in the laboratory to classify and size defects with a degree of accuracy than would be feasible with ITD NDE. Destructive testing of defects also offers many advantages, including confirmation of defect type, size, and time dependency as well as confirming local material properties.

#### 11.5.7 Verification of ILI by Hydrostatic Testing

An operator may elect to hydrostatically test portions of an assessment segment to confirm that the crack ILI tool has sufficiently identified critically sized defects. However, verification by hydrostatic test fails to provide confirmation that non-critically sized defects were sized correctly by an ILI tool or that subcritical failure pressures were accurately estimated. For these reasons, verification by hydrostatic testing is recommended only for situations where an operator needs to definitively prove that no critically size defects are currently present on the selected test segment when other methods cannot reliably verify ILI performance to a high degree of confidence.

### 11.6 Crack Tool Response Methodology

#### 11.6.1 General

This section of the RP focuses on the specific indications within the ILI results that could be related to potential cracking. In the event that an ILI crack tool finds other anomaly types (dents, metal loss, etc.), these indications should be addressed under those response criteria outlined in API 1160. This methodology can be applied to any ILI technology. Most ILI reports do not use the term crack, rather a set terms defined by the ILI service provider are used such as linear indication, planar indication, etc. This methodology can be applied to all ILI service providers' definitions used to identify potential cracks.

Since there are many types of capable ILI crack assessment technologies, differing service provider definitions, and varying operator experience, a comprehensive methodology for guiding operators to find and repair injurious cracks is required. The methodology makes the connections between complex characterization of ILI signals (call-outs), the propensity for those call-outs to actually be injurious cracks, and a common set of response protocols. Pipeline operators are strongly discouraged from asking crack ILI vendors to conduct the analyses described in this practice; vendors are discouraged from changing their reporting terminology to match those used herein. Each crack ILI inspection has unique factors such as the following:

— known or suspected cracking threat(s) and their characteristics,

— specific capability of the ILI technology and service provider,

— pipe characteristics including steel vintage and manufacturing techniques,

— crack ILI history of operator and of the specific line,

— level of inspection validation,

— method of field NDE or other in situ crack measurement,

— operator experience and risk profile and tolerance,



— operational history of the pipeline.

These unique factors necessitate that an effective response methodology should be flexible, consider all of the data that an operator can collect, and leverage improvements in crack detection technology and advancements in industry understanding of crack threats.

### 11.6.2 Methodology Overview

The central part of this methodology is determining the appropriate response action to each indication called out by a crack ILI tool. The ILI response methodology high-level workflow is illustrated in Figure 11. The first step is determining the likelihood that the indication called by the vendor actually correlates to a crack or crack-like defect as opposed to a non-crack-like indication. SCC, hook cracks, lack-of-fusion, HIC, shrinkage cracks, etc., would be considered crack-like indications. Corrosion, misalignment, trim features, etc., would be considered non-crack-like indications. The operator could analyze each characterization category of graded ILI results as a collection of similar indications rather than analyzing individual call-outs when applying this methodology.

Likelihood classifications are, in general terms, as follows:

— Likely Crack,

— Possible Crack,

— Unlikely Crack.

The determination of likely and possible cracks requires experience and knowledge. If an operator lacks the needed experience and knowledge, they should default to Likely Crack. Once the likelihood that an ILI indication is a crack has been determined, the likely failure mechanism and its corresponding time dependency must be identified. Useful

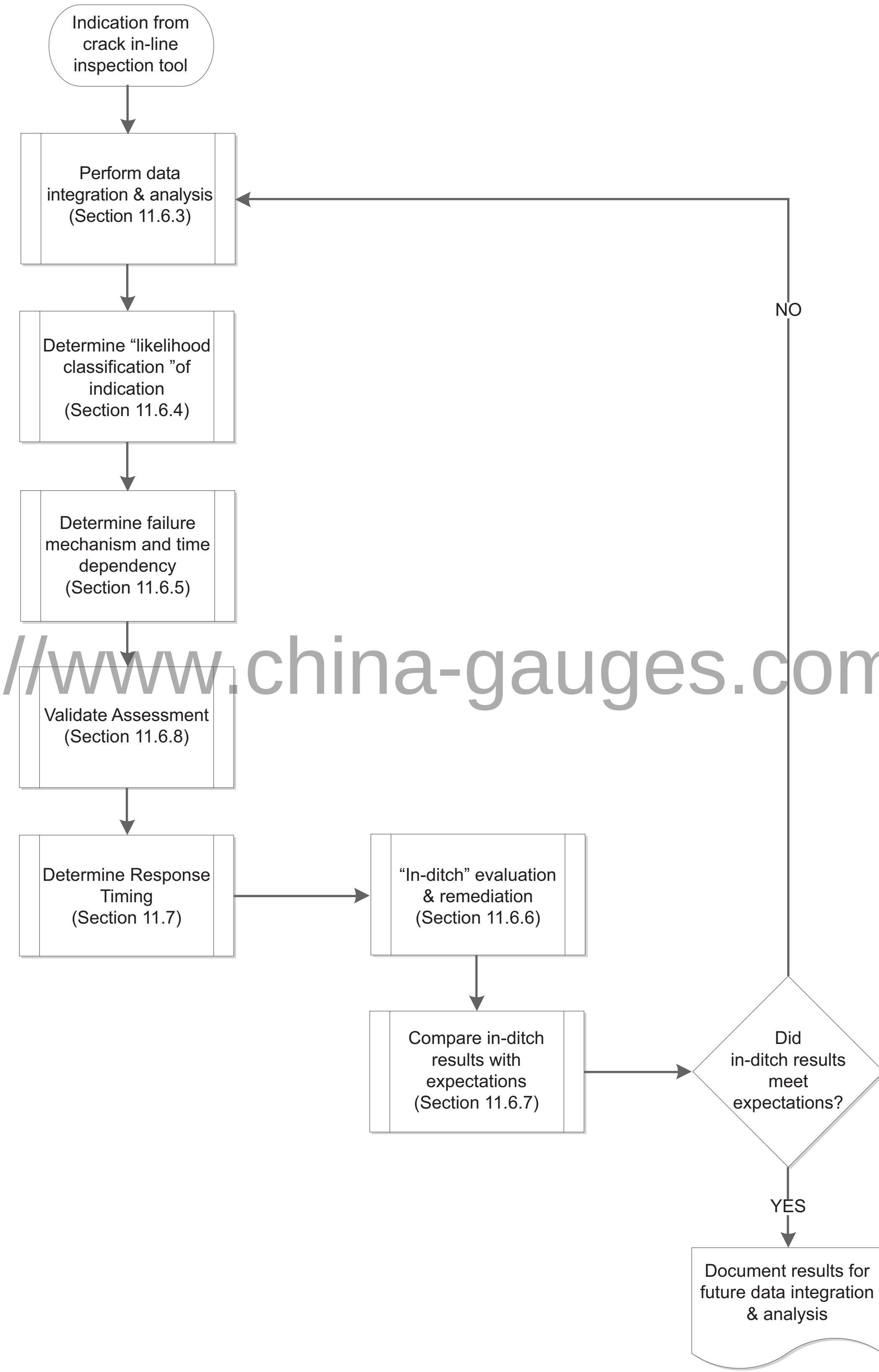





**Figure 11—In-line Inspection Response Methodology High-level Workflow**

categorizations of time dependency are time-dependent, potentially time-dependent, and not time-dependent. Correct categorization of this time dependency is critical to properly determining the response time.

If an operator lacks a process for classifying the failure time dependency of defects, the operator should default to categorizing them as time-dependent.

A critical concept in this approach is iterative application of knowledge gained as representative samples of indications are excavated, evaluated, and compared to remaining indications. A well-developed approach may include several iterations of the methodology.

The comprehensive methodology involves several steps as follows:

a) data Integration and analysis of results according to predefined protocols,

b) determination of likelihood of actual crack,

c) determination of growth mechanism and time dependency,

d) assessment validation,

e) determination of response timeline,

f) excavation and characterization of defects,

g) analysis of results and iterative re-application of methodology (as applicable).



Each of these steps will be discussed in detail in following sections. Effective response methodologies should include a decision protocol or workflow for each call-out type that enables the operator to work through these steps, integrate all relevant data, come to a conclusion of which response classification is appropriate in that instance, and document the results.

When operators perform crack ILI assessments for technology development or prove-up, it is important that each operator have a predetermined plan or set of protocols for how and when the results are eventually applied against the response criteria. This plan can involve multiple iterations of the below presented methodology or some metric that determines that the technology is currently adequate for the current application or set of pipeline characteristics. This plan should identify the level and types of confirmation data to be used (such as excavation results, hydrostatic testing, and proven crack ILI results). The intent is to allow operators to evaluate new technology and drive its development without being locked into response actions by data that are suspected to have increased uncertainty.

Given the disparate naming conventions used by the various ILI vendors and differing correlation experience of operators, a means of mapping the features as reported by the ILI into a common frame of reference that characterizes their integrity relevance is required. Specifically, the operator should understand the potential existence of a valid cracking mechanism, typically referred to as susceptibility, to account for the presence of the ILI anomaly. A Likely Crack directly proceeds to remediation in the prescribed timeline. However, given the industry's experience with the large proportion of crack ILI anomalies that are field-validated as non-injurious, the other classifications of Possible Crack and Unlikely Crack reflect the potential of an iterative response program with a protracted timeline.

The operator should develop a rationalization in regards to the classification of the reported ILI crack features. An example would be an operator investigating multiple notch-like features in a representative number of excavations and field-validating them as being non-injurious variation in the manufacturing process. In this instance, the operator could reasonably classify this feature type as Unlikely Crack.

Some known data about the type of cracks present in a line segment are needed before the classification process should be finalized. Operators without extensive crack ILI experience should have positive confirmation in the form of

ITD NDE results for each classification before finalizing their crack ILI response effort. Conservative default response timing should also be used when no relevant data or analysis processes are available. Alternatively, an operator choosing to run an unproven ILI technology for development purposes may elect to classify features less conservatively until validation efforts provide positive or negative correlation to crack-like features.

### 11.6.3 Data Integration and Analysis

How each crack ILI indication gets classified into one of the above response levels is an operator-specific data analysis. A critical part of the analysis determining the types of data that operators should consider and how they integrate those data. This RP does not intend to establish rules whereby ILI vendors' call-out names are always put into the same response classification. Because of the uniqueness of each inspection and related factors, not all classification analyses should be the same. Different operators, because of their experience, may have a different protocol for establishing what should be a Likely Crack. A single operator may have different protocols for determining Likely Cracks for lines with different inspection or failure histories. In instances where there is no prior relevant history, the data integration and classification process can be iterative; an operator will dig a selected number of each crack ILI indication, examine the results, and then decide the appropriate classification level or select further indications for excavation. In some instances, several cycles of dig, analyze, and re-classify might be necessary before the proper classifications can be confirmed for all indications.

When determining the likelihood of an indication being an actual crack, questions operators should consider throughout the process include the following.

a) *Prior to Reporting*

An operator should gather and analyze all relevant data from assessment segment and similar segments, including historic field inspections, lab analyses, in-service and hydrotest failures, manufacturing process, vintage, operational profile, environment, etc., along with industry datasets to expand their comparative process. Using this data, the following questions should be considered.



— What crack-like features are expected?

— What crack-like features are impossible or improbable?

— What is the likelihood of a crack-like defect being time-dependent (manufacturing process, vintage, operations, environment, etc.)?

b) *Data Analysis*

Upon receiving a crack ILI report, an operator is able to make additional inferences based upon reported feature type, orientation, location in comparison to longitudinal seam, and alignment to previously reported and/or inspected features. Using these ILI results, the following questions should be considered.

— Is the vendor anomaly call logical, given the reported location on the pipeline?

— Does the vendor anomaly call make sense given the reported location in the pipe (orientation, location in seam versus body, etc.)?

— Does the anomaly correlate to a non-crack feature reported in a different ILI dataset?

— In the case of metal loss (i.e. corrosion), is it reasonable to assume the defect is misclassified by the ILI tool, or do interacting defects exist?

— Does the anomaly correlate to a historic investigation confirmed to be crack-like?

— Does the anomaly correlate to a historic investigation confirmed to be a non-crack?

c) For evaluation/validation, the following questions should be considered.

- — Do ITD and/or destructive testing confirm or refute the existence of crack-like defects?
- — Did the ILI vendor's analysis process and reporting nomenclature reliably identify crack-like features in accordance with stated performance specifications?
- — Can the defects investigated be reliably validated as non-time-dependent?

It is a good practice for each operator to develop a data analysis process that gathers and organizes relevant data as well as a protocol to sort each crack ILI indication into response a classification. One option is to develop template documents for these processes that are customized for each crack ILI inspection and could serve as a permanent record for that segment. An example ILI response protocol can be found in Annex L (see Figure L.1). The processes should accomplish the following:

- — identify available and necessary data,
- — document thoroughness of analyses,
- — identify knowledge gaps or assumptions used.

Since operators typically run crack ILI tools in response to a specific threat, the data needed to properly classify the results will possibly be dependent on that threat. Refer to other sections in this RP that discuss the susceptibility of each threat for a comprehensive list of data that should be considered.

### 11.6.4 Likelihood Classifications



This methodology translates a set of ILI indications into a list of actionable anomalies that are segregated into three likelihood classifications as follows.

- — *Likely Crack*—High certainty that the indication called by the ILI vendor correlates to a crack-like defect. This can be the case where the operator's previous experience on the present pipeline segment or other similar pipeline segment has found cracks or the case where the data integration indicates a strong likelihood that cracks could exist even though no historical data suggest so. Examples include the following.
  - — Crack ILI-reported indications that when excavated are confirmed to be cracks a high percentage of the time.
  - — Crack ILI-reported indications that have not yet been investigated, and the operator has no experience or information to indicate that the indication is not a Likely Crack.
- — *Possible Crack*—A crack ILI-reported indication that in the operator's previous experience has reduced certainty of being or rarely been an actual crack, and when it is a crack, it occurs under different circumstances or the operator cannot determine with certainty that the indication is NOT a crack-like defect. Examples include the following.
  - — Crack ILI-reported indications that are typically confirmed to be non-crack features.
  - — Crack ILI-reported indications (as called-out) that would otherwise be classified as Likely Cracks except that data integration indicates that these types of cracks are improbable (crack-like indication on modern ERW pipe).
  - — Crack ILI-reported indications (as called-out) that are stated by the vendor to have a reduced certainty in being an actual crack-like feature (i.e. seam weld Feature B, weld anomaly, manufacturing anomaly, etc.). Subject to operator correlation.

— Crack ILI-reported indications (as called-out) that would otherwise be classified as Likely Cracks except that the operator has extensive crack inspection experience and has not found this type of indication on the line segment or similar segment (e.g. a "crack field" call-out on a pipe segment with no observed or reasonably suspected environmental cracking threat).

— Crack ILI-reported indications from an experimental tool run or new ILI technology under prove-up where previous cracks have been found on the line segment with proven technologies.

— *Unlikely Crack*—A crack ILI-reported indication that, in the operator's previous experience, has a high certainty to correlate to a non-crack-like feature or imperfection. Also, crack ILI-reported indications that, after data integration, indicate a strong likelihood that no cracks exist or that the indications are other types of defects such as notches, ERW trim anomalies, etc. Examples include the following.

  — Crack ILI-reported indications reported to have characteristics of a crack that are almost always confirmed to be non-cracks such as notch-like, weld anomalies, or mill defects, and when correlated to a crack-like feature, the feature has been verified as non-injurious.

  — Crack ILI-reported indications that have been found to be Likely Cracks on other pipeline segments, but the operator has extensive crack ILI experience on the pipeline segment in question and has not found crack-like features.

  — Crack ILI-reported indications that would otherwise be classified as Likely Cracks except that data integration, operator experience, and industry experience indicate that these types of cracks are highly unlikely or not known to occur (e.g. a "crack field" call-out in FBE-coated pipe).

  — Crack ILI-reported indications from an experimental tool run or new ILI technology under field trials in a operating pipeline where no cracks have been found on the line segment with proven technologies.



### 11.6.5 Determining Growth Mechanism and Time Dependency

Part of the data integration and analysis used to determine the likelihood that a set of indications are cracks involves understanding of the types of cracks that can be present and, therefore, the likely growth to failure mechanisms for those cracks. From an understanding of these mechanisms, operators can determine if the failure mode of these cracks have a factor of time dependency or in response to specific events or pipeline change could eventually become time-dependent. This understanding is critical in determining if a response is needed and when it should be made. For the purposes of determining the proper response criteria, three levels of failure mechanism time dependency have been identified as follows.

— *Time-dependent*—An imperfection identified by a crack ILI tool whose characteristics suggest a high likelihood of correlating to a time-dependent defect whose predicted failure pressure is possibly actively declining due to environmental and/or operational factors.

— *Potentially Time-dependent*—An imperfection identified by a crack ILI tool and correlated to a feature that is typically stable; however, it remains possible to transition into a time-dependent defect; e.g. a lack-of-fusion or hook crack feature in post-1970 HF-ERW pipe with reliable material properties.

— *Non-time-dependent*—An indication that can be identified by a crack ILI tool that can be reliably correlated to a stable feature or imperfection that is unaffected by environment or segment operations; e.g. a notch-like indication in seamless pipe in noncyclic service.

For those indications determined to be time-dependent, the operator should understand the method of growth for the potential crack so that a response can be properly scheduled. Also, for indications that are considered potentially time-dependent, operators should identify conditions (or changes in conditions) that can cause the indication to become time-dependent. For a detailed discussion on failure mechanisms, crack growth rates, or changes in conditions that could lead to a change in time dependency, refer to specific threat discussions included throughout this document.

### 11.6.6 Excavation and Characterization of Defects

The ILI process should be validated by examining detected anomalies on the pipe whether they are excavated or available on aboveground piping. It is critical that the characterization of the defect be made by the appropriate NDE technology and that it includes measurements of length, depth, profile where possible, other required parameters, and includes a determination of the type of cracking. Detailed descriptions of some of the relevant NDE technologies for the characterizations of cracks can be found in Section 14.

The validation of POD is important to understand the inspection results. However, POD is a not a number but rather a function of many independent variables. Often, the data necessary to determine a complete POD surface require the presence of numerous cracks of a wide variety of sizes that have been detected by an ILI tools and a similar number that have been not been detected; many pipelines do not have sufficient cracks to generate a full POD curve. As a place to start, a simple qualitative measure of POD defined in Equation (6) can be useful:

$$\text{qualitative POD} = \frac{\#\text{ by ILI}}{\#\text{ by ILI} + \#\text{ by other}} \tag{6}$$

where

# by ILI is the number of confirmed cracks identified by ILI;

# by other is the number of cracks found by other methods that have sufficient size to be detect by the ILI tool.



This qualitative measure is useful in assessing relative ILI tool performance. To support validation of any measure of the POD, consider extending the excavation and ITD examination upstream and downstream per 11.5.1 to an extent that is practical to identify unreported cracks that exceed the detection threshold of the ILI.

The quality of the ITD NDE is an important factor in verification of ILI results. For body cracks, grinding has been one of the most reliable verification methods. For verification of seam cracks, the results of ITD should be considered to have wide uncertainty until proven by destructive assessment. When verifying crack ILI results for crack length, operators should note that some ILI-based UT technologies have limited ability to measure cracks in the very outer layer [1 mm (0.040 in.) or so] of the pipe wall. If a crack ILI inspection is consistently under-calling crack length when compared to ITD NDE, operators should consider either removing this outer “layer” before measuring length or asking the ITD NDE technician to report the crack length at the depth at or just below this “layer.”

A pipeline operator should also anticipate some frequency of false calls or benign defects. This reality is expected to persist for some ILI technologies until more inspections, tool enhancements, field validations, and software algorithm improvements are made over the coming years. For further guidance on calibration and verification, refer to API 1163.

### 11.6.7 Analysis of Results

Once defects have been characterized in the field, the results should be fed back into the data integration and analysis process and both qualitatively (defect type) and quantitatively (defect sizing) compared to the expected values. Two important analyses are needed. The first analysis is to compare the defect characterization results against the crack ILI tool results. Making this comparison requires thorough knowledge of an ILI tool POD and POI to know if the tool results are valid. Negative results from this comparison can result in the need for an inspection re-grade, re-run of the same technology, or the use of an alternate crack ILI technology.

The second important analysis is to compare the characterized defects with their expected likelihood classifications and types. Negative results from this analysis require that the operator perform another iteration of the data integration and analysis process, likelihood classification process, and ultimately, characterize more defects in the ditch. A well-developed approach may include several iterations of the methodology.

It can also be valuable to provide defect characterization results to the ILI service providers for a possible re-grade of an individual assessment or for the service provider to use in grading algorithm improvements.

#### 11.6.8 Classification Methodology Validation

As the previous sections indicate, the ILI results can vary from detection of many anomalies, some of which could be cracks, to accurate detection with identification of anomaly types and sizing. The wide range of results depends on steel properties, pipe fabrication variables, inspection tool technology, tool performance, and data interpretation. While ILI providers specify the performance of specific technology, this is a general set of performance measures. Under optimal conditions, the ILI tools can perform much better than specification; under suboptimal conditions, performance can fail to meet the specification. It should be noted if an ILI tool fails to meet specification and impacts the integrity of the pipeline, the operator may use additional means such as additional digs or additional engineering data analysis.

The range of steel properties, fabrication variables, and operating conditions make it difficult to generalize ILI tool performance. Furthermore, many variables are associated with the specific inspection, including tool setup, product flow, and data analysis (a fairly manual process). Therefore, it is necessary to validate results for each pipeline inspection.

Operators should validate that the sizing of cracks is accurate within specification. Operators should also validate that the classification methodology correctly identifies cracks and other features. This validation can be conducted through a sample set of excavations or comparison of ILI results against well-characterized defects known to exist in the pipeline. Regardless of the source of initial validation data, operators must strive to have some representative data for all classifications of indications (Likely Crack, Possible Crack, and Unlikely Crack) so that the operator can have high confidence that these classifications have correctly been assigned and negatives can be confirmed. If initial data do not support how the classifications have been assigned, multiple iterations of validation could be necessary. It should be noted that ITD NDE results used to verify tool performance (Section 14) can also be used to validate the classification methodology. Examples of validation activities could include the following.



— *Validation by Past ILI*—Investigate and/or correlate with historic investigations a statistical sample of Possible and Unlikely Crack anomalies.

— *Validation by Defect Characterization*—Investigate and/or correlate with historic investigations a statistical sample of potentially time-dependent and non-time-dependent features.

When an operator lacks sufficient data points for validation or the above methods for validating the classification results do not provide adequate confidence, operators should consider additional validation through destructive testing via hydrostatic testing or defect cutout and follow-up metallurgical analysis. Data from these activities can be used for both tool performance verification and for validating classification decisions.

If the correlation efforts above are based on historic data, a sample of new investigations should be considered to confirm that conditions on the segment have not changed since prior assessment.

Operators should develop a minimum number of data points needed for validation of each response classification and should provide justification for when the selected number is not representative of the overall defect population. Operators with extensive experience with a specific crack ILI technology on a set of similar pipelines can leverage this experience when validating a specific tool run and response determination. Also, past history for the segment in question can be used. The required sample size to validate each classification set could be different. Thorough knowledge of an ILI tool potential and actual POD and POI is critical when validating indication classification with a lesser number of validation points. Acceptable validation of the likelihood classifications should be achieved within 365 days of final report receipt. It is recognized that achieving higher levels of validation, such as obtaining cutout samples of features, can extend beyond 365 days.

#### 11.6.9 Estimation of Remaining Crack Size

An estimate of the largest crack remaining in the pipeline should be determined and used in the FFS calculations (Section 7) and the remaining life analysis (Section 8). Data that can be used to determine the remaining defect population and size include:

— ILI results; both current and previous results,

— ITD inspection results, including both ILI-reported and unreported cracks found in the ditch,

— cutouts and other destructive testing,

— other information, such as results of a previous hydrostatic test.

When ILI and ITD results do not correlate, statistical methods can be helpful in reconciling conflicting data. ILI tool detection threshold is one approach used to establish the largest remaining crack dimensions, when only a few cracks are detected and verified and once all necessary repairs have been completed.

### 11.7 Crack ILI Response Criteria

#### 11.7.1 General

Whether an indication requires response or not is often determined by the application of one or more specific FFS analyses. From an FFS analysis, predicted burst pressure, also referred to as estimated rupture pressure (ERP), can be calculated and compared to operating pressures in order to understand the factor of safety. A variety of FFS analysis techniques are available and operators should understand which FFS analysis is most appropriate for each type of potential crack defect and corresponding failure mechanism. When performing FFS analyses, operators should consider the accuracy of the ILI inspection, stated and known (actual) tool tolerances, and other situation-dependent factors when determining safety factors. Examples of the different types of FFS analyses to use can be found in Section 7. An important aspect of determining severity is having a comprehensive understanding of the potential growth mechanism for the indication and when the indication could grow to an injurious size. An operator can either select which indications to remediate, thereby setting the reassessment interval, or can select the reassessment interval, thereby setting which indications to schedule for remediation. A discussion of the applicability of response criteria when hydrostatic testing as part of the assessment is also included.

The comparison of ERP to operating pressure is called the failure pressure ratio (FPR). The FPR is defined as the ERP divided by either the predicted transient (surge) pressure or the current established MOP/MAOP at the crack location. The intent is that the operator may choose which of these pressures to use for the FPR comparison, not to require the operator to compare to both and respond if either comparison fails. When deciding to use transient pressures or MOP/MAOP, operators should consider the availability and accuracy of transient calculations, accuracy of data to support such calculations, and other operational factors.

#### 11.7.2 Immediate Response Conditions

Immediate response conditions describe anomalies or conditions that could potentially represent severe and immediate threats to pipeline integrity. They require prompt action by an operator regardless of whether they are found within a segment of pipeline that could potentially impact a critical area. Prompt action usually consists of excavation and repair and/or restriction in operating pressures to maintain safety margins. These criteria are not intended to include tool tolerance in depth comparisons or ERP calculations.

Criteria for immediate conditions are as follows:

— a Likely Crack whose predicted depth is greater than 70 % of nominal pipe wall OR the maximum depth sizing capabilities of the tool, as stated by the vendor's performance specification, where the depth cannot otherwise be established through correlation with previous ILI runs;

— a Likely Crack with an FPR less than 1.1;

— a Likely Crack or Possible Crack indication predicted to interact with a dent.

### 11.7.3 365-day Conditions

The following conditions describe anomalies that could, if left unaddressed over long time periods, represent eventual threats to pipeline integrity. Action usually consists of excavation and repair and/or restriction in operating pressures to maintain safety margins. Operators should understand the growth mechanism for each defect considered for the 365-day condition criteria and verify that the time to failure (including appropriate safety factors) of these defects is not less than 365 days. Indications that are predicted to fail within this period should be scheduled for remediation prior to their projected failure date. These criteria are not intended to include tool tolerance in depth comparisons or ERP calculations.

Criteria for 365-day conditions are as follows:

— a crack ILI indication whose predicted depth is greater than 50 % of nominal pipe wall that has been determined to be one of the following:

  — a Likely Crack that is time-dependent or potentially time-dependent,



  — a Possible Crack that is time-dependent;

— a crack ILI indication with an FPR less than 1.25 that has been determined to be one of the following:

  — a Likely Crack that is time-dependent or potentially time-dependent,

  — a Possible Crack that is time-dependent;

— if not already available through previous correlation data or required excavations, a representative sample of the crack ILI indications that considers both the likelihood and time-dependency characterizations identified by the operator.

Once enough of these indications have been excavated and evaluated to validate the classification process, the remaining Indications will be re-analyzed and re-classified as scheduled or monitored indications.

### 11.7.4 Scheduled Conditions

When determining the schedule for conditions that include Likely Cracks, the operating pressure of the pipeline and the estimated number of pressure cycles should be considered and/or other time-dependent growth mechanisms. Investigations should be scheduled to be completed before anomalies are predicted to elevate to a more serious criterion. If the schedule is longer than a subsequent reassessment, then the reassessment data should be used to adjust the schedule accordingly. This analysis could result in features that require a response on a schedule that could be less than 365 days. As such, all Likely Cracks that meet criteria for 365-day conditions must be included in this analysis to confirm whether repair schedules for those conditions should be accelerated. This analysis must include anomalies with repair schedules beyond a subsequent reassessment, and operators must meet all repair schedules until "discovery" is met on a subsequent reassessment.

It is acceptable to implement a reduced operating pressure that will result in extended repair schedules for Likely Cracks or Possible Cracks. Changes in operation that result in more aggressive pressure cycling should be flagged as needed, and the pressure data should be used to confirm whether associated repair schedules are still acceptable.

Two options are presented for selecting criteria for determining scheduled conditions. The options are presented so that operators can achieve an equivalent level of safety despite having varying levels of ILI experience, confidence in the cracking threat, and detailed understanding of local operating pressures at the indication locations. Operators need not select the most conservative option. Operators may choose an option on an indication-by-indication basis. Operators should choose the option that best fits their knowledge of their pipeline and of the cracking threat present.

Criteria for scheduled conditions are as follows.

— *OPTION 1*

When a time-to-failure analysis of a crack ILI indication that DOES include tool tolerances reaches an FPR less than 1.1 or reaches a depth of 70 %, is determined to be time-dependent, and is a Likely Crack or Possible Crack.

— *OPTION 2*

When the half-life of a time-to-failure analysis of a crack ILI indication that DOES include tool tolerances that reaches an FPR of 1.0, is determined to be time-dependent, and is a Likely Crack or Possible Crack.

The operator may establish tool tolerances as specified above by using vendor-specified ILI tool tolerances and/or the tolerance of the individual ILI assessment as established by ITD confirmations, failure history, and/or cutouts.

#### 11.7.5 Monitored Conditions



An operator does not have to schedule the following conditions for remediation but should record and monitor the conditions during subsequent integrity assessments for any change that could require attention:

— all remaining crack ILI indications that were determined to be time-dependent but whose schedule exceeds the reassessment interval (regardless of likelihood classification);

— all remaining crack ILI indications that were determined to be potentially time-dependent (regardless of likelihood classification).

#### 11.7.6 Applicability of Response Conditions when Also Hydrostatically Testing

When an operator conducts both hydrostatic testing and crack ILI, not all of the listed response criteria need be followed. If the hydrostatic test pressure-to-operating pressure ratio exceeds the response criteria, excavations may not be required.

This approach does not remove the need to validate the accuracy of the ILI inspection if the reassessment interval is to be based on ILI. Otherwise, the reassessment interval should be calculated using the hydrostatic test.

Excavations may be done before or after the hydrostatic test, but responding to some of the conditions before the test, particularly any immediate conditions, can prevent costly hydrostatic test failures.

## 12 Hydrostatic Testing

### 12.1 General

Hydrostatic testing [4] is a widely used method of establishing or revalidating the integrity of a pipeline. It is required almost universally to validate the serviceability of a newly constructed pipeline, and it can be used to revalidate the integrity of an existing pipeline after it has been in service for a period of time. Its value as an integrity assessment technique is embodied in the probability that the increasing of test pressure beyond the operating pressure will cause defects that are critical at the test pressure to fail and thereby eliminating the possibility that the defects could fail at the operating pressure. Additionally, the ratio of the hydrostatic test pressure to MOP/MAOP quantifies the safety factor with respect to failure.

A hydrostatic test can be used instead of ILI where ILI is not an option or where inspection tools might be incapable of detecting the threat identified on the pipeline; hydrostatic testing can also be used to validate the results of inspection tools.

Hydrostatic testing to a level in excess of the MOP/MAOP provides a positive verification of the ability of a pipeline to be operated safely at the MOP/MAOP. The margin of safety is embodied in the ratio of test pressure to operating pressure and not the maximum test pressure alone or some fixed percent of SMYS. The higher the test pressure-to-operating pressure ratio, the larger will be the margin of safety. Rather than determining a test pressure based on a fixed percent of SMYS, the operator should determine a test pressure level by evaluating data such as the previous test pressure levels, the age of the pipeline, the cause of any previous test or service failures, the current MOP/MAOP, and the remaining life associated with the test pressure.

Hydrostatic testing is suitable for assessing anomalies associated with time-dependent and stable threats. Specific threats need to be matched with the integrity assessment options. Where it is an appropriate assessment method, however, a test either eliminates defects that have failure pressures less than the test pressure or it shows that any surviving defects have failure pressures at or above the test pressure (except for the possibility of a pressure reversal as explained below).

Hydrostatic testing has some technical limitations. First, the only anomalies identified by a hydrostatic test are those that fail during the test. Anomalies having failure pressures above the test pressure will not be discovered. This means that short, deep anomalies (that have inherently high failure pressures) could go undetected. Moreover, the operator gains no knowledge of the numbers and locations of anomalies that have survived the test. A further difficulty with establishing a maximum flaw size with hydrostatic testing is the necessity to make assumptions regarding material properties in calculating critical defect size. As noted earlier, for the purpose of establishing a flaw size for fatigue crack growth analysis, the assumption of upper bound toughness and/or yield strength is necessary to ensure conservatism. Therefore, in establishing the time for the next integrity assessment by testing, the operator should assume that the failure pressure of the most severe remaining anomaly is no higher than the test pressure and that the anomaly could be located anywhere within the segment. Unless a large number of defects fail during the test, the pipeline operator learns little or nothing about the locations of potential anomalies and time-dependent threats where phenomena such as SCC or pressure-cycle-induced fatigue may be taking place.



The successive cycles of test pressure may cause other anomalies to grow such that successive failures can occur at pressure levels below that of a prior pressurization (see pressure reversals in 12.5).

Cumulative damage evaluations should consider the effects of stress cycles associated with hydrostatic testing over the life of the pipeline.

Initial hydrostatic test failures should be examined to determine the cause of failure in sufficient detail to inform the crack management process. Details on data gathering during a hydrostatic test, required documentation procedures, and analysis of the results can be found in API 1110.

## 12.2 Minimum Test Pressure-to-Operating Pressure Ratio

Typical strength test levels are a minimum of 1.25 × MOP/MAOP and leak test levels of 1.10 × MOP/MAOP. If the test pressure is expected to approach SMYS, a yield plot should be performed to mitigate the potential for plastic yielding of the pipe wall.

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[4] Hydrostatic testing usually refers to pressure tests conducted with water as the pressurizing fluid. The use of the term hydrostatic in this document does not preclude pneumatic testing where permitted by standards or regulations.

## 12.3 Minimum Hold Time

Holding the test pressure at a constant level for a period of time is an appropriate method to detect leaks. Beyond the regulatory requirements, the length of hold time employed to look for leaks should be based on the volume of water in the test section: the larger the volume, the longer holding at constant pressure is required to detect a leak of a given size. It should be noted that the value of hold time is solely that of establishing that the test segment is free of leaks. It does not add to the value of the test with respect to the margin of safety. Defects that are on the verge of failure at the test pressure can continue to grow during the hold period. If a growing defect fails, it is eliminated and the hold period should be restarted. If no failure occurs during the hold period, but one or more defects grow without failing, the hold time has potentially made the defects worse. Since there is no way to determine the status of defects that survive the hold period, the test pressure is the sole measure of the effectiveness of the test with respect to the margin of safety for operating the pipeline at its MOP/MAOP.

## 12.4 Spike Testing

### 12.4.1 General

A hydrostatic spike pressure test is one that is conducted initially at a high pressure or hoop stress level, relative to the operating pressure, held for a short time, followed by an extended hold period at a lower pressure level. The spike portion of the test could exceed the mill pressure test or a hoop stress equal to SMYS of the pipe, or not, depending on the purpose of the test and the characteristics of the pipe.

It is only necessary to achieve and hold the high pressure for a short time to establish the integrity of the pipeline. The spike portion of the test is held for a long enough time to assure that the pipeline has experienced a continuous pressure at or above the target level, and to cause defects that are near critical (near the point of failure) to fail, but not so long as to cause additional crack growth in defects that are too small to be near the failure point (referred to as subcritical). Consistent with that objective, ASME B31.8S recommends a minimum period of 10 minutes [ASME B31.8S-2012, Paragraph A-3.4.2(b)]. The effectiveness and value of the spike portion of the test is not improved by a longer period and extended hold periods at near-failure levels can be counterproductive.



The spike test is a variant of the hydrostatic proof test. Its purpose is two-fold: the spike portion of the test will induce failure in the pipe where significant defects are present, while the subsequent relaxation of pressure allows any surviving cracks to stabilize and avoids subcritical crack growth during the hold period to detect leaks.

### 12.4.2 Suitability

#### 12.4.2.1 General

Three categories are identified for the suitability of a spike test, as follows:

1) advisable,

2) discretionary, and

3) inadvisable.

#### 12.4.2.2 Advisable

Spike testing is beneficial and therefore recommended in these specific circumstances:

a) where crack-like defects such as SCC, selective corrosion of ERW seams, bondline defects in older vintage ERW seams, and seam fatigue cracks are expected to exist based on evidence from inspections, failures, or consideration of pipeline integrity threats;

b) where it is desired to increase the reassessment interval for time-dependent flaws, particularly in high-stress pipelines;

c) where documentation or empirical observations are unable to confirm the attributes of the pipe relevant to establishing susceptibility to cracking mechanisms (e.g. wall thickness, grade, seam type, cause of the prior seam ruptures) or is unable to confirm that a prior hydrostatic test has occurred.

#### 12.4.2.3 Discretionary

Spike testing may not be necessary in the following situations:

a) where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present;

b) where the proposed test pressure to operating pressure ratio is at least 1.4 (because pressure reversals larger than 40 % of the test pressure are highly unlikely);

c) where the operating stress is below 40 % of SMYS in natural gas pipelines designed in accordance with Class 3 or Class 4 requirements;

d) where the pipe being tested is new and of known good quality.

#### 12.4.2.4 Inadvisable

Spike testing to higher than the standard test level would be inadvisable in a limited set of specific circumstances, including the following:



a) where the spike test pressure would damage the pipe, particularly pipe susceptible to manufacturing defects in seams that would not otherwise fail without a spike test;

b) where the spike test pressure would exceed the recommended maximum test pressure of components such as flanges or valves;

c) where the strength margin above the spike test pressure could be insufficient to prevent excessive stress due to fluid thermal expansion effects during the test;

d) where accommodation of large elevation changes is necessary during testing;

e) where pneumatic testing is practiced.

### 12.5 Pressure Reversals

Pressure reversals refer to occurrences of failures during a hydrostatic test or during the process of entering service after a test at a pressure lower than a previously experienced pressure level. Experimental tests [37] determined that pressure reversals occur as a result of subcritical crack growth of defects that were near failure during the previous test cycle but that did not fail before the pressure was reduced, either because another defect failed or the test was concluded without failure. In addition, damage from compressive yielding at the crack tip and exhaustion of ductility are contributing factors.

Additional tests performed in similar material to the test described above demonstrated that the failure pressure of a defect held to near the point of failure decreases the longer it is held at that point. The relative damaging effect of hold time was shown to be greater with more severe defects and greater with proximity of the hold level to the immediately critical stress level. [37]

The operator cannot know from the pressure test alone about defects that do not fail during the test. Therefore, the operator cannot be certain that at the successful conclusion of a pressure test that there is not a defect present that was near failure at the time that the test was terminated. This would be the case irrespective of the test level or the test duration. Holding the pipe at its maximum test level potentially leaves the pipe in worse condition than would a shorter duration hold at the same maximum test level.

Pressure reversals can happen during hydrostatic tests of pipeline segments that contain families of defects having similar failure pressures. The likelihood of a pressure reversal of a given size can be calculated based on the type of frequency distribution that best fits the pressure reversal data. The analysis using this approach was demonstrated in Task 1.5 of the PHMSA ERW study and showed that the probability of pressure reversal occurring at a size that would threaten the integrity of the pipeline at its operating pressure is negligible after a successful hydrostatic test.

## 13 Stress Corrosion Cracking Direct Assessment

Direct assessment (DA) is a methodical process for identifying and investigating locations on buried pipelines where corrosion has or could potentially occur. The process has been adapted to address external corrosion, internal corrosion, and SCC. The stress corrosion cracking direct assessment (SCCDA) process is described fully in NACE SP0204.

The SCCDA process consists of the following four steps: pre-assessment, indirect inspections, direct examinations, and post-assessment. These are described briefly below.

— *Pre-assessment*—Historic and currently available data are collected and analyzed to prioritize the segments within a pipeline system with respect to potential susceptibility to SCC and to select specific sites within those segments for direct examinations. The types of data to be collected are typically available from construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, and inspection reports from prior integrity evaluations or maintenance activities.



— *Indirect Inspections*—Additional data are collected to aid prioritization of segments and site selection. The type of indirect inspections necessary depends on the nature and extent of the data obtained from the pre-assessment. Typical data collected might include close-interval survey data, DC voltage gradient data, and information about terrain along the ROW.

— *Direct Examination*—Aboveground measurements and inspections are performed to field-verify the factors used to select the dig sites; e.g. the presence and severity of coating faults. If predictive models based on terrain conditions are used, the topography, drainage, and soil type require verification. The digs are then performed. The severity, extent, and type of SCC, if detected, at the individual dig sites are assessed. Data that can be used in post-assessment and predictive model development are collected.

— *Post-assessment*—Data from the previous steps are analyzed to determine whether SCC mitigation is required, and if so, to prioritize those actions, to define the interval to the next full integrity reassessment, and to evaluate the effectiveness of the SCCDA process.

Data identified to be of potential value for the management of SCC include parameters that can be used to conduct preliminary assessments of initiation susceptibility and for selection of excavation inspection sites. Depending on the volume of data collected, it might be possible to derive correlations for different aspects of crack development such as crack initiation, growth, or other significant processes.

In many cases, the data have been shown to have a relationship to some aspect of SCC. In other cases, operational experience and the results from research suggest some correlation, and the collection of these data is considered to have value in the context of continuous improvement of SCC management. The dataset proposed in this section should be used as a guideline only. Each operator should evaluate their system and decide whether additional parameters are valuable.

Data should be collected from all investigation activities such as ILI, validation digs, hydrostatic tests, repairs, failures, and opportunistic digs. However, data should be analyzed to support the choice of assessment method; e.g. data that need to support SCC DA can differ significantly from data that need to support ILI.

Implementation of a field excavation program provides the opportunity to record observations on several aspects of the pipe, including the terrain where the excavation is located, the performance of the materials of construction, the environment in contact with the pipe, and possibly characteristics of cracking or other pipe anomalies.

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

Data should be collected concerning the following categories:

— weld and pipe characteristics;

— terrain, including topography, stratigraphy, soil consistency, and drainage;

— buoyancy control;

— pipe-to-soil potentials;

— coating characterization and condition;

— undercoating liquids and corrosion products;

— SCC characterization, including dimensions, extent, type, and depth;



— other attributes such as toe cracks or mechanical damage.

The CEPA RP provides sample data collection tables, which can be useful for achieving complete and consistent data recording.

# 14 In-the-Ditch Assessment

## 14.1 General

In-the-ditch methods are used to detect, identify type, and size anomalies identified as possibly being cracks by ILI. These methods should also be used on pipelines to assess identified cracking threats at excavations that expose the pipe. The application of ITD inspection methods has more dependence on the inspector in both the way they are applied and results that are achieved. The operator should have written procedures for information collection associated with each inspection method. Inspectors should have certifications of proficiency in the inspection modality used; one such certification is a Level II or III certification from the American Society for Nondestructive Testing (ASNT). Operators can request inspectors have additional performance demonstrations for specific technologies or crack types. Procedures and recorded data should be consistent from one year to the next for comparison of results and detection of changes. For inspector safety, pipeline pressures should be evaluated and often lowered. Guidance can be found in ASME B31.4. Many ITD tests require the coatings to be removed and the pipe to be cleaned. General guidelines are given in the following sections and additional details are provided in Annex K.

## 14.2 Assessment of SCC and Other Pipe Body Cracks

### 14.2.1 General

When potential body cracks such as SCC are identified by ILI and excavation sited are selected, soil condition assessment, electrolyte sampling, and coating evaluation should be made at some of the excavation sites. General soil condition assessment and electrolyte sampling during excavation should be considered to the extent needed to assess the environmental conditions that could lead to this crack type. Similarly, measurement of the extent of the disbond of the coating and general photographic documentation during excavation should be considered at some of the excavation sites to the extent needed to assess the general coating conditions on the pipeline. Soil condition assessment, electrolyte sampling, and coating condition evaluation does not need to be performed at every excavation site.

Then the entire circumference of pipe exposed to the facilitating environment should be inspected using MPI or comparable method. Blasting media should be chosen to minimize alteration of the crack opening that could limit crack detection by inspection methods. Examples of soft abrasive media include walnut shells, plastic abrasives, and sodium bicarbonate. The MPI method is an efficient screening tool with the inspection of a standard pipe joint taking less than an hour; the documentation time is proportional to the number of anomalies detected. A photograph of crack indications should be provided in the inspection report. For daylight inspection, the most common approach for pipelines, a very thin white layer of paint is applied to the pipe and black particles are used to detect cracks as illustrated in Figure 12.



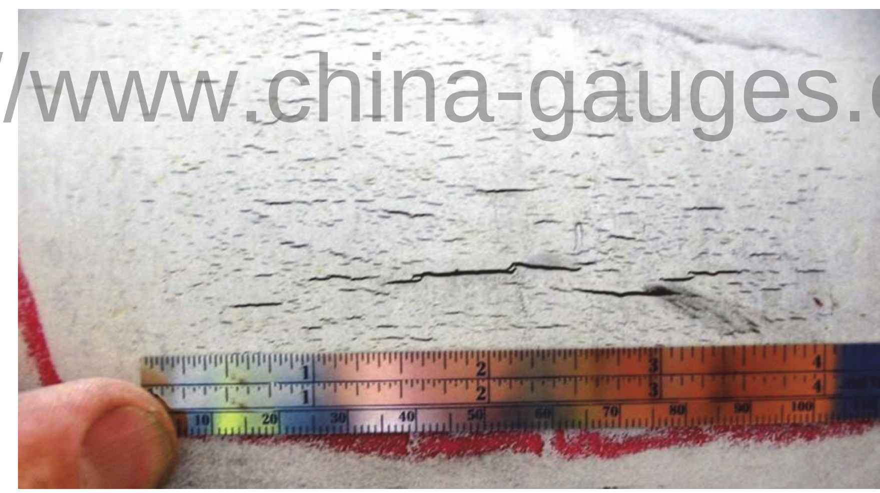


**Figure 12—Result of a Magnetic Particle Inspection for Stress Corrosion Cracking**

The length of the crack is visually determined using MPI, with experience needed to apply sufficient particles to enhance the ends of the crack. An experienced technician should analyze the MPI results and/or the resulting photograph and determine the maximum interlinking length of the colony. MPI method is not generally used to determine the depth of crack since the amount of particles that accumulate at narrow crack-like anomalies is related to the width of the crack as well as the depth. Both NDE and grinding methods are used to determine depth of body cracks.

### 14.2.2 NDE Methods for SCC Depth Assessment

Many ultrasonic and electromagnetic methods are available for sizing cracks in the ditch. These methods are most accurate when cracks are more isolated, and the accuracy is significantly compromised if the most significant crack is in the middle of a large colony with many nearby cracks. Ultrasonic methods include classic shear wave, time-of-flight diffraction (TOFD), and phased array. Eddy current sensor systems are also available.

The accuracy of these methods varies with some results showing accuracies in the range of 10 % of wall thickness under ideal conditions, while some blind tests show minimal correlation with depth as determined by metallurgical sectioning. The skill and training of the inspector are significant factors in the quality of results that are achieved. While absolute depth sizing of cracks can have inaccuracies, the methods can typically determine relative size cracks throughout a pipeline. Calibration of ITD methods for cracks removed from service can be used to improve results. The length as determined by ITD and ILI are often different as ITD methods such as MPI include very shallow portions of crack that are below the detection threshold of the ILI tool.

#### 14.2.3 Grinding for Crack Depth Assessment

The length and depth of axially oriented cracks such SCC and fatigue cracks can be determined through the iterative process of buffing, MPI, and measurement of remaining wall thickness. Operators typically permit buffing as a method of defect repair up to a depth of 20 % to 40 % of nominal wall thickness. If SCC indications remain beyond the buffing limit, a sleeve suitable for repairing cracks could be required. Additional information can be found in Section 15.

Additional engineering considerations should be made for buffing performed under any of the following circumstances:

— SCC is circumferentially oriented (because these are formed by bending stresses that are not reduced by lowering the line pressure),

— SCC located inside a dent or coincident with any deformation,

— SCC near the seam is dependent on seam type and material properties. Some operators restrict grinding on LF-ERW (pre-1970) pipe or any pipe with seam welds that are more brittle than the base material.



### 14.3 Assessment of Longitudinal Seam Cracks

#### 14.3.1 General

ITD methods for seam weld inspection are used to provide more information on anomalies detected by ILI tools. These methods can also be used to inspect any pipe that has been excavated; this is a practice more often performed when the pipeline has had a history of cracking problems and when the weld seam is of specific fabrication method and vintage to assess the potential for future problems. The ERW inspection process involves detecting the weld, screening the weld, and detailed sizing. The details of the common methods used are outlined below.

#### 14.3.2 Identifying the Seam Location

The first step in assessing the ERW seam weld is identifying the location of the seam. For an ERW seam that is smoothly trimmed, the seam can be difficult to detect. Depending on the manufacturer, the ERW seam is sometimes detectable by excess metal, electrode markings, or other production features. If there are no external markings, the next step is to check the seam weld for a slight wall thickness variation due to over-trimming at production. Experienced inspectors can often find hard to detect the welds by lightly gliding their fingertips around the circumference of the pipe. A more quantitative approach to identify the long seam uses ultrasonic equipment to measure changes in wall thickness due to trim variation. Another NDE method to locate the seam is ultrasonic shear wave inspection to detect ID trim variation.

While trim variation is a general identifier of seam location, polishing and etching can be used to establish interface between the two edges of the skelp. One method to identify seam location is a 10 % nitric acid etch. Other etchants are possible. Electrochemical etching is possible using a salt water batch and a DC potential applied between the pipe (positive) and a copper electrode (negative). The etching can be performed by many NDE contractors using their procedures.

### 14.3.3 Screening for Seam Cracks

For seam welds, consideration should be given to inspecting the entire seam using MPI. The methodology is similar to SCC assessment. An example is shown in Figure 13; the black lines are potential linear indications in the HAZ of the seam weld. The linear indications need to be quantified by other methods to assess anomaly type depth and relationship to the bondline.

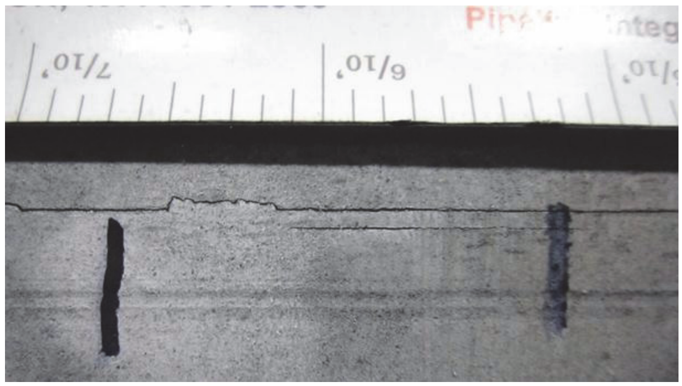


**Figure 13—Result of a Magnetic Particle Inspection of Seam Crack**

Magnetic particle inspection detects most OD surface breaking flaws. On occasion, subsurface flaws can be detected; the ability to detect subsurface flaws depends on the proximity to the surface, the width, the area of the discontinuity, and pipe surface condition such as smoothness and pitting. The length of the anomaly is visually determined, with experience needed to apply sufficient particles to enhance the ends of the anomaly. ID and midwall cracks are detected using ultrasonic methods, including angled beam inspection, TOFD, and phased array. For screening, automated scanning system systems that record data for a long portion of the seam are beneficial.



### 14.3.4 Assessing Detected Seam Cracks

For detected cracks in seam welds, many ultrasonic methods are used to quantify seam anomalies including TOFD and phased array along with propriety shear wave methods. For verification of seam cracks, the estimates of depth should be considered with conservatism until proven by destructive assessment.

## 14.4 Assessment of Surface Breaking Laminations

### 14.4.1 General

Where a lamination has turned through-wall and breaks to the ID or OD surface, it can be assumed the ligament of steel between the planar lamination and the pipe surface no longer shares any load, leaving the remaining ligament susceptible to plastic collapse. The remaining ligament can be assessed as a metal loss feature. Alternatively, guidance provided within API 579-1/ASME FFS-1 would have the operator assess the through-wall component of the lamination as a crack (i.e. it presumes the presence of crack tip stress intensification in the remaining ligament). A key consideration in this approach is delineating the extent of the lamination that has turned through-wall and only assessing that portion as a crack since the purely planar portion of the lamination is non-injurious.

### 14.4.2 NDE Methods for Surface Breaking Laminations

The extent of the planar lamination can determined with compressive wave ultrasonic techniques. The perimeter of the planar lamination can be inspected with classic shear wave ultrasonic techniques using various angles of incidence (e.g. 45, 60, and 70) to delineate the portion of the lamination edge that has turned through-wall and would be assessed as a crack.

#### 14.4.3 Grinding for Assessment

Grinding can be useful where the apparent surface breaking portion of a lamination is just a surficial scab that coincides with it. However, surface blistering could be indicative that hydrogen charging has created the lamination and the potential presence of hydrogen induced cracking.

# 15 Repair Methods

## 15.1 General

Anomalies found to be injurious to pipeline integrity on the basis of engineering critical assessments (ECAs) should be repaired by an acceptable repair method to a qualified written procedure. Acceptable repair methods for a wide variety of defects are described in the current editions of ASME B31.4 and ASME B31.8. Both safety codes require that cracks be repaired. Cracks are generally considered to be more severe than blunt defects because they tend to fail in a toughness dependent mode rather than plastic collapse.

Table 2 below lists acceptable repair methods for various categories of defects. The defect categories were selected because they are types of cracks or defects that could contain cracks. The defect types or categories are defined throughout this document. See API 1160 for acceptable repair strategies. For safety considerations during repairs, additional guidance can be found in API 2200.

The repair methods can be considered to be of two types: repairs for cracks and repairs for metal loss after cracks have been removed. An appropriate repair strategy would be removal of cracks by grinding, assessment of the metal loss by an acceptable ECA method, and repair of the metal loss if required. Alternatively, the pieces of pipe containing injurious defects may be cut out and replaced with previously hydrostatically tested pipe. If pipe replacement is the chosen repair method, the replacement pipe should meet the design criteria of the pipeline and should have been tested prior to commissioning to a level of at least 1.25 times the MOP/MAOP, and the tie-in welds should be radiographed. As a temporary mitigative measure or to protect personnel conducting a repair, the operator may choose to reduce the operating pressure of the pipeline. When a pressure reduction is employed to mitigate the effects of an anomaly, the time limit before a permanent repair should be made should be calculated in accordance with the method shown in API 1160, Annex C. Acceptable repair methods include but are not necessarily limited to the following:



- replace as cylinder,
- grinding,
- deposition of weld metal,
- full encirclement sleeves,
  - reinforcing (Type A),
  - pressure containing (Type B),
- composite sleeves,
- compression sleeves,
- mechanical bolt-on clamps,
- hot tapping.

## 15.2 Replace as Cylinder

Cracks may be removed by cutting out the affected section of pipe as a cylinder and replacing it with a section of pipe with an equal or greater design pressure. The replacement pipe must meet the design requirements for the full MOP/MAOP of the pipeline. Where possible, the replacement section should have a length no less than one-half the pipe diameter or not less than 76.2 mm (3 in.), whichever is greater.

## 15.3 Grinding

Cracks may be removed by grinding within the limits stated below. Grinding by hand filing or power disc buffing is widely accepted for repairing superficial and some more significant defects such as gouges or cracks. Prior to grinding, limits on grinding imposed by the operating pressure, the remaining wall thickness, and the proximity of defects should be considered. Grinding is permitted to a depth of 10 % of the nominal pipe wall thickness with no limit on length. Grinding is permitted up to a depth of 40 % of the wall thickness provided the length of the grind repair does not exceed the allowable length based on ASME B31G (2009 or later), Modified B31G, RSTRENG, or ASME B31.8-2012 §841.4.2(3). This 40 % limit does not apply where an additional external repair will be applied. The grinding must produce a smooth contour in the pipe wall. The remaining wall thickness must be verified by UT. In the case of arc burns, the surface should also be inspected with an etchant to ensure complete removal of affected microstructures. If any portion of the crack remains, the pipe must be repaired by another method.

## 15.4 Deposition of Weld Metal

Weld metal deposition repairs involve depositing weld metal over a defect to replace missing metal. The technique is applicable only to metal loss defects or areas where any other type of defect has been removed by grinding to create an open pit-like area for deposition of weld metal. Associated with the technique is the inherent risk of burning through the remaining wall thickness. Any live-line welding should be conducted based on a qualified procedure.



## 15.5 Full Encirclement Sleeves

Repairs may be made by the installation of full encirclement welded split sleeves as follows.

— Reinforcing full encirclement (Type A) sleeves are comprised of two half-sleeves joined by means of an axial weld on both sides. The ends of the sleeve are not welded to the pipe; hence, a Type A sleeve may not be used to repair a leak. A crack must be entirely removed without penetrating more than 40 % of the wall thickness. These sleeves function as reinforcement to a defective pipe, and they do not need to carry much of the hoop stress to be effective. It is essential to have the sleeve in intimate contact with the pipe at the area of the defect to prevent it from bulging outward and perhaps failing. Any gap that exists at that location should be filled with a hardenable filler of appropriate compressive strength, such as epoxy or polyester material.

— Pressure-containing full encirclement (Type B) sleeves are comprised of two half-sleeves joined by an axial weld on both sides. The ends of the sleeve are fillet welded to the pipe so as to make the sleeve capable of containing the pressure in the event the defect leaks. These sleeves should be designed to carry the full MOP/MAOP of the pipeline. The side seams should be full penetration butt welds.

Both Type A and Type B sleeves should be sized so that they extend a minimum distance of 50 mm (2 in.) beyond the ends of the defect being repaired.

## 15.6 Composite Sleeves

Composite sleeves consist of a fiber-reinforced matrix and come in a variety of forms and are comprised of a variety of materials. All are patented devices offered by vendors who may perform the installations or provide training for the operator's personnel to install the sleeves. The known types of fibers used are carbon fibers and glass fibers. The matrix materials are usually either a polyester material or an epoxy material. One style of wrap consists of a preformed composite. Layers of the composite are successively wrapped around the pipe as they are coated with an adhesive to create a solid composite sleeve upon curing. Another style of sleeve consists of laying up the composite in a “wet” matrix so that the final sleeve becomes a solid composite upon curing.

Composite sleeve repairs reinforce a defective pipe in much the same manner as a Type A steel sleeve. Therefore, using a hardenable filler to achieve continuity at the defect is necessary. Composite sleeve repairs cannot be used to repair leaking defects or cracks, unless the crack has been completely removed by grinding. Some composite wrap materials can be incompatible with all environments (such as contaminated soil). Operators should carefully follow the manufacturer's instructions during installation.

### 15.7 Compression Sleeves

Compression reinforcing sleeves are an application of steel reinforcing full encirclement sleeves, but where the sleeve is designed and installed in a manner that results in the transfer of all hoop stress from the carrier pipe to the sleeve. The sleeves are installed while hot so that when cooled to ambient temperature the shrinkage of the steel sleeve creates a state of net compression in the carrier pipe. The hoop stress in the sleeves should not exceed the maximum design stress of the sleeve material. Testing of compression sleeves removed from service has shown that they have been successful in preventing growth of the pipe defects. Compression sleeves have been in use since the late 1990s and have no reported history of failure. A commentary on steel compression sleeves is given in CSA Z662 standard.

Because the hoop stress in the carrier pipe is relieved by the installation of the compression sleeve, it is unnecessary to remove the stress concentrator in the carrier pipe by grinding prior to the repair. Like Type A reinforcing full encirclement steel sleeves, compression sleeves are not designed to carry any axial loads and therefore are unsuitable repairs for circumferentially oriented defects whether in the carrier pipe or girth welds.



### 15.8 Mechanical Bolt-on Clamps

Mechanical bolt-on clamps consist of two half-circumference steel forgings that are placed around a defective segment of pipe and bolted together via axial flanges on both sides. The clamp halves are equipped with elastomeric seals along the sides and at both ends, which upon tightening of the bolts, seal the internal annular space between the pipe and the clamp. The clamp is capable of carrying the full MOP/MAOP of the pipeline. The compatibility of this seal material should be checked against the product within the pipeline. Before installation, seal materials should be inspected as some of them have limited shelf lives.

### 15.9 Hot Tapping

Cracks or other defects may be removed by hot tapping. The defect should be completely contained within the coupon removed through the hot tap fitting.

### 15.10 Fittings

The use of fittings to repair cracks is not recommended.

The applicability of each of these repair methods to various types of anomalies is shown in Table 2.

## 16 Preventive and Mitigative

### 16.1 Mitigating Transit Fatigue

An operator ordering new pipe can mitigate a transit fatigue concern by requiring manufacturers or stockpilers of line pipe to observe API 5L1 when loading pipe onto rail cars or API 5LW when loading pipe onto a marine vessel.

## 16.2 Reevaluation of Pressure Data

Pressure data that are used for determining relative aggressiveness and/or remaining lives should be reevaluated annually, every 3 years, or every 5 years in accordance with Annex B to determine that no appreciable change in operations has occurred. A pipeline that changes from a relatively nonaggressive mode of operation into an aggressive mode of operation could require additional assessments.

Additionally, remaining life calculations assume that a set of current operation pressure cycles will be representative of future operation. If a pipeline changes in its cyclic operations, a predicted remaining life may be reduced (or increased) and the reassessment interval should be adjusted accordingly. When a pipeline has significant operational cyclic changes during a reassessment interval, two-staged growth calculations can be performed to capture both modes of operation and to provide the most accurate remaining life.

## 16.3 Managing of Pressure Cycles

While operational pressure cycles are generally inherent in a hazardous liquid pipeline, some measures could be possible to reduce the number of pressure cycles. Both the size of pressure cycles (maximum to minimum pressure) and the number of cycles contribute to degradation. While these methods might not be possible on all systems, some operators have been successful at reducing the number and intensity of pressure cycles as follows:

— reducing shutdowns,

— holding backpressure,

— using friction-reducing additives,

— modifying product batching and delivery and receipt schedules,



— minimizing pump starts and stops.

## 16.4 Stress Corrosion Cracking

Some possible preventive measures include the following:

— repair all SCC discovered in the field or indicated by ILI,

— improve or upgrade CP for lines not coated with PE tape or PE heat shrink sleeves,

— perform hydrostatic pressure spike test to eliminate significant SCC and extend time to failure,

— perform ILI on accelerated schedule,

— reduce operating temperatures (where high-pH SCC is the concern),

— reduce MOP/MAOP to less than a threshold stress (at the crack tip $\Delta K$) for the worst SCC feature expected to remain in place after integrity assessment and remediation,

— reduce severity of pressure cycling.

Some possible mitigating measures include the following:

— apply conservative repair criterion such that any failure could only occur as a leak,

— install leak detection system in populated or environmentally sensitive areas,

— recoat or replace segments of PE tape coated pipe.

## Table 2—Acceptable Crack Repair Methods

| Type of Anomaly | Repair Methods | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 1 Replace as Cylinder | 2 Removal by Grinding | 3 Deposition of Weld Metal | 4a Reinforcing Full Encirclement Sleeve (Type A) | 4b Pressure-containing Full Encirclement Sleeve (Type B) | 4c Compression Sleeves | 5 Composite Sleeve | 6 Mechanical Bolt-on Clamp | 7 Hot Tap |
| Selective seam corrosion, LF-ERW or DC-ERW or EFW [a] | Yes [b] | Yes [a] | No | No | Yes | Yes | No | Yes | Yes [c] |
| Any leaking defect [a e] | Yes [b] | No | No | No | Yes [d] | No | No | Yes | No |
| Crack in dents < 6 % of the diameter [a] | Yes [b] | Yes [e] | No | Yes [e] | Yes | Yes [j] | Yes [e] | Yes | No |
| Crack in dents > 6 % of the diameter | Yes [b] | No | No | No | Yes | No | No | Yes | No |
| Crack in girth weld | Yes [b] | Yes [f] | Yes [g] | No | Yes | No | No | Yes | No |
| SCC—axial | Yes [b] | Yes [e] | Yes [g] | Yes [e] | Yes | Yes | Yes [e] | Yes | Yes [c] |
| SCC—circumferential | Yes [b] | Yes [e] | Yes [g] | No | Yes | No | No | Yes | Yes [c] |
| Cracks in ERW seam—DC-or LF-ERW or unknown ductility | Yes [b] | Yes [h] | No | No | Yes | Yes | No | Yes | No |
| Cracks in ERW seam—HF-ERW known to be ductile | Yes [b] | Yes [e] | No | Yes [e] | Yes | Yes | Yes [e] | Yes | Yes [c] |
| Cracks in prior repairs—puddle welds | Yes [b] | Yes [f] | Yes [g] | Yes [e] | Yes | Yes [i] | Yes [e] | Yes | Yes [c] |
| Cracks in prior repairs—Type B sleeves | Yes [b] | Yes [e] | Yes [g] | No | Yes | No | No | Yes | No |
| Cracks in buckles/wrinkles | Yes [b] | No | No | No | Yes | No | No | Yes | No |
| Cracks in hard spots | Yes [b] | No | No | No | Yes | Yes | No | Yes | No |

[a] Note 1—from ASME B31.4-2012.

[b] Replacement pipe should have a minimum length of one-half of its diameter or 76.2 mm (3 in.), whichever is greater, and shall meet or exceed the same design requirements as those of the carrier pipe.

[c] Crack must be contained entirely within the area of the largest possible coupon of material that can be removed through the hot tap fitting.

[d] Leaking defects should be stopped before attempting a repair by use of a Type B sleeve.

[e] Crack or other defect must be entirely removed and removal should be verified by visual and magnetic particle or dye-penetrant inspection. Grinding is permitted to a depth of 10 % of the nominal wall thickness with no limit on length. Grinding is permitted to a depth of 40 % of the nominal wall thickness provided the length of the grind repair does not exceed the allowable length based on ASME B31G (2009 or later), Modified B31G, RSTRENG, as referenced in ASME B31.4-2012 Paragraph 451.6.2.2(b) or ASME B31.8-2012 Paragraph 851.4.2(c)(3). This 40 % limit does not apply where an additional external repair will be applied. Use filler material with steel and composite sleeves to fill the void between the pipe and the sleeve.

[f] Grinding should not reduce the thickness of the weld below the wall thickness of the mating pipe.

[g] Crack or must be completely removed by grinding and removal verified by visual and magnetic particle or dye-penetrant inspection. The welding procedure specification shall define minimum remaining wall thickness in the area to be repaired and maximum level of internal pressure during repair. Low-hydrogen welding process must be used.

[h] May be used only if crack, stress riser, or other defect is entirely removed, removal is verified by visual and magnetic particle or dye-penetrant inspection (plus etchant in the case of arc burns), and the remaining wall thickness is not less than 87.5 % of the nominal wall thickness of the pipe.

[i] Surface of welds should be ground flush with pipe surface to ensure tight fit.

[j] Use filler material to fill annular space.

# 17 Crack Management Performance Measures

## 17.1 General

A key component to evaluating crack management performance is to measure the effectiveness of the integrity assessments at removing critically sized flaws from the pipeline. For ILI, detection and accurate sizing of flaws are essential to allow operators to respond appropriately.

## 17.2 Performance Measures by Crack Threat

Crack threat (integrity threats that can lead to cracks) performance measures should consider the activities performed to identify and assess the integrity threat, the operational factors that affect the integrity of the pipeline related to the threat, and integrity measures used to mitigate the threat. These performance areas are referred to as process measures (also called activity measures), operational measures, and integrity measures.

Operators should select as many performance measures as required based on their system. The time period over which performance is measured can vary because it could take years rather than weeks or months to achieve a meaningful measurement of the effectiveness of some integrity assessment, mitigation, and preventive measures. Yearly performance measures are not limited to the list below, but these are provided as some examples:

— planned hydrostatic tests versus hydrostatic tests completed,

— planned crack ILI versus crack ILI completed,

— miles of crack ILI versus number of SCC anomalies detected,



— miles of crack ILI versus number of seam like cracks detected,

— excavations performed versus excavations performed using magnetic particle testing,

— excavations performed using magnetic particle testing versus excavations performed where SCC was identified,

— excavations performed using magnetic particle testing versus excavations performed where hook cracks were identified.

## 17.3 Performance Measures by Crack Assessment Method

### 17.3.1 General

The performance of each crack assessment method should be evaluated. Crack assessment methods currently include hydrostatic testing, certain ILI technologies, and various types of DA methods. The different aspects of performance include the following:

— performance of the integrity management process,

— operational integrity management activities,

— improvement achieved as a result of the integrity assessment, remediation, and mitigation activities.

### 17.3.2 In-line Inspection

In-line inspection is used to detect and characterize flaws so that the operator can assess the severity of the flaws and remediate appropriately. ILI technologies respond differently to different types of flaws and cracks. Flaw orientation, position in the pipe, and proximity to other features (such as longitudinal seam welds, dents, or other features) can affect the performance of the ILI tool with respect to detection or characterization or both. The selection of an ILI technology should consider the type(s) of flaws and cracks that are to be assessed.

The performance of the tool is affected by how it is run in the pipeline. The cleanliness of the pipeline, elevations, and the pressure differentials and speed of the tool can all affect the performance of the tool.

Validation digs are routinely performed to evaluate the tool performance at specific locations. These data are collected and displayed in unity plots to assess the tool performance in a broader sense. Sizing error will affect the assessment of the severity of the features called out and thus affects the effectiveness of the integrity assessment.

Examination of the pipe adjacent to ILI call-outs can sometimes uncover flaws not reported by the ILI vendor or not detected by the ILI tool. The more adjacent pipe that is inspected, the larger is the sample size. Each instance of the tool having missed a significant flaw should be discussed with the ILI vendor to attempt to determine that factor(s) that could have caused it to be missed.

Some ILI performance measures include the following:

— number of successful versus unsuccessful runs;

— types of cracks found by the ILI technology;

— number of miles inspected, the number of cracks called out, and the number of cracks investigated;

— evaluation of vendor's stated accuracy with a unity plot of crack depths (predicted depth from the ILI tool versus actual depth measured in the field);



— number of cracks found (within detection limits) that were not reported by the tool;

— number of cracks called out but not found on the pipeline (false calls);

— POD;

— probability of characterization;

— sizing accuracy.

### 17.3.3 Hydrostatic Testing

Hydrostatic retesting is used to identify due to a test failure critically sized flaws from the pipeline before they can fail in service. The effectiveness of the test [5] is related to the margin between the hydrostatic test pressure level and the MOP/MAOP level. The greater the margin, the more effective is the test and the greater the safety factor.

The hold time of the test affects the ability to detect small leaks that could be present in the pipeline during the test, but it does not significantly impact the effectiveness of the test with respect to defect removal. Shorter test section lengths of smaller diameter pipelines are more sensitive to small leaks than are longer test sections of larger diameter pipelines.

Hydrostatic test failures, leaks, and ruptures should be examined to determine the cause. The identification of defects during a hydrostatic test should be incorporated into the operator's integrity management program. Other useful information that can be gained from examination of hydrostatic breaks is the relative size of the defect during the test

[5] Note that at low MOP/MAOP levels, the effectiveness of the test is reduced with respect to time-dependent degradation, because relatively large flaws can survive the test and remain in the pipeline. The growth rate, particularly with pressure-cycle induced fatigue crack growth, of these large flaws can be significant.

versus the size of the defect that would be expected to fail at the operating pressure. Particular attention should be paid to flaws that fail at a pressure level lower than either a previous hydrostatic test or the mill test pressure. These occurrences imply that the flaw has grown larger over time while in service.

Some hydrostatic test performance measures may include:

— margin between test pressure and operating pressure levels;

— number of test failures from cracks, leaks, or ruptures;

— pressure levels at which failures occur;

— sizes of defects that could have just survived the hydrostatic test.

### 17.3.4 Direct Assessment (DA) Methodologies

Direct Assessment (DA) methods generally involve collecting, organizing, and assessing indirect measurements or data to identify locations with a relatively higher likelihood of containing a flaw. SCCDA is the one DA method that involves cracks. It relies on data evaluation to locate areas where SCC is possible or likely and excavations in those areas to look for the presence of SCC on the pipeline.

The effectiveness of an SCCDA program is related to the number and severity of SCC colonies found at SCCDA excavation sites and other excavation sites. The size of the overall SCC colony as well as the severity of the SCC should be documented.

Some SCCDA performance measures include the following:



— number of SCC colonies found and severity of SCC in SCCDA excavations as well as other excavations,

— environmental conditions at SCCDA excavation sites.

# Annex A
(normative)

# SCC Additional Information

## A.1 SCC Monitoring and Assessment

If a segment of pipe is determined to be susceptible based on the aforementioned criteria, the operator should perform opportunistic MPIs of the pipe surface where the coating is disbonded at all excavations if possible. These results should be assessed against an understanding of the susceptibility factors to ensure the excavations are representative of susceptible sites, as is generally the case for sites targeting external corrosion. A formalization of this investigative screening process is encompassed by NACE SP0204. The more rigorous SCCDA approach is merited where the risk is elevated or in response to prescriptive requirement (typically associated with elevated consequences). Although the different approaches for the detection and assessment of SCC leverage data integration to varying degrees, it is particularly important in regards to SCCDA.

However, since it has been observed that SCC can be superficial (the occurrence of shallow, nonpropagating cracks), the designation of "noteworthy" SCC should be used to clearly communicate the threshold for moving from a nominal monitoring phase into an active assessment/mitigation phase regarding the SCC threat on a particular pipeline asset. "Noteworthy," as defined in ASME STP-PT-011 with the inclusion of a criterion based solely on depth, represents an enhancement of the term "significant" that was originally defined by CEPA in regards to SCC and then adopted in NACE SP0204. The importance of the depth-dependent criterion is that it encompasses the potential for short deep cracks associated with high-pH SCC. Both ASME STP-PT-011 and CEPA's *Stress Corrosion Cracking Recommended Practices* provide a further delineation of the crack severity into a ranking scheme, with the ASME criterion providing more clarity through its unequivocal reference to failure pressure. Although it is implicit, in the event of a segment sustaining an in-service or hydrostatic test failure where SCC is identified as the cause, one would proceed to active assessment for and mitigation of the SCC threat.



The effective management of noteworthy SCC requires an operator to develop a program in consideration of the specifics of the pipeline and the limitations of the assessment techniques and technologies as applied. The effective management of noteworthy SCC typically requires periodic assessment via hydrostatic testing or ILI using a crack-detection tool.

## A.2 SCC Susceptibility Conditions

### A.2.1 General

External SCC in pipelines occurs in two modes: "classical" or high-pH SCC and near-neutral pH SCC. The two modes are associated with separate, specific, and mutually exclusive conditions. Despite this apparent specificity, whether SCC will actually occur or should ever be expected to occur has a degree of uncertainty, because whether those conditions are actually present, or always present, or the degree to which they could be present, cannot always be determined with certainty. Consequently, SCC is discussed in terms of "susceptibility" as a function of the presence of certain causal factors or supporting conditions known to promote the occurrence of SCC. The more causal factors present, or the more often they are present, then the higher the likelihood that SCC could be present now or could occur eventually. The importance of individual factors on susceptibility is rated as "low," "medium," or "high." Expectations for SCC occurrence will be substantially informed by prior discovery of SCC in the same pipeline or in another pipeline under the same or similar conditions.

### A.2.2 Materials

In general, all line pipe materials, base metals, weld metals, seam types, grades, and vintages are susceptible. Certain pipe vintages (1950s through 1970s) are more frequently associated with SCC, primarily because they make up a significant proportion of total mileage and certain susceptibility factors were prevalent with pipelines of those periods of construction. Operation of natural gas compressor stations without aftercooling was common in systems constructed in the 1940s and 1950s, while the usage of field-applied plastic tape as the primary coating was prevalent in the 1960s through 1980s.

No specific pipe grade or pipe produced by specific manufacturers is either immune or preferentially susceptible to SCC. However, an operator's experience may indicate higher or lower rates of occurrence of SCC affecting pipe from specific sources. Reasons for this could include the following:

a) manufacturer-specific pipe forming processes that result in high residual stresses, or

b) coating processes used with pipe from a specific source or by a specific contractor on a given project or spread.

Reason a) is not typical but has been observed occasionally. Reason b) represents a circumstance in which pipe from one source may have been prepared and coated differently (or to a different level of quality) in one project or one spread within a project than pipe from another source used in another project or spread. In that case, the pipe manufacturer is a false susceptibility factor.

Pipe diameter is not a strong influencing factor. SCC has been identified on pipe ranging from DN 20 to DN 1200 [nominal pipe size (NPS) 3/4 to NPS 48]. Larger diameters can be more affected by shear stresses at the pipe-soil interface that can wrinkle or disbond some coatings. Small diameter pipe is more likely to develop axial stresses due to soil movement or external forces that are much greater than hoop stresses due to internal pressure, affecting the orientation of cracking.

### A.2.3 Stress Level



Most pipelines operate at some stress level by design, often at moderate to high stress levels, and therefore possess this causal factor unavoidably. A lower-bound threshold of stress below which SCC cannot occur has not been defined, but the severity of SCC in terms of growth rates or density of cracking within colonies has been observed to increase with increasing stress levels above 60 % SMYS. Approximately 85 % of reported occurrences of SCC have been above this threshold. The crack driving force for SCC is most often the hoop stress due to internal pressure. This suggests that the segments of pipe closest to the discharge of pump stations or compressor stations have the highest susceptibility, all other conditions being equal. This is often observed to be the case but has not precluded SCC occurring at points closer to the suction end of a pipeline segment.

Where the highest stress component is longitudinal, due typically to a soil movement phenomenon, the hoop stress level is not a factor. In fact, circumferential SCC has been observed in pipe operating at very low levels of hoop stress.

### A.2.4 Stress Cycling

Cyclical stresses have an influence on the rate of stress-corrosion crack growth, as well as provide the potential for crack growth by fatigue under the influence of stress cycles of sufficient frequency and magnitude.

In the case of high-pH SCC, a thin $Fe_3O_4$ passivating layer forms on the steel surface. If this film remains intact, no crack growth occurs. If the steel is strained sufficiently, the brittle oxide film cracks, exposing the pipe surface to conditions that could promote crack initiation or advancement. The oxide film reforms over newly exposed surfaces at the crack tip and is again ruptured by a subsequent application of sufficient plastic strain. Cyclic loads thus lead to repeated cycles of exposure, crack advancement, and redevelopment of the oxide film.

In near-neutral pH environments, crack growth is driven interactively by dissolution and hydrogen. Atomic hydrogen is generated by corrosion reactions at the crack tip, on the crack walls, and on the disbonded pipe surface. Some of this hydrogen diffuses into the steel and is transported to the high stress zones at and near the crack tip, embrittling the area. The presence of hydrogen weakens interatomic bonds and promotes brittle crack growth. Alternatively, in the high triaxial stress zone ahead of the crack tip, it can promote the flow of dislocations along slip planes, localizing strain and enhancing the coalescence of microvoids, potentially leading to the formation of a microcrack. In the case of blunt dormant cracks, the formation of a microcrack ahead of the crack tip can turn the blunt crack into a sharp crack when the microcrack propagates back to the blunt crack tip. The majority of cracks in the field are dormant, which is supported by laboratory results where dormancy was observed at large R-ratios and low cycle frequencies. However, infrequent unload-reload events (e.g. a depressurization cycle) were sufficient to either increase crack velocities or reinitiate dormant SCC. Also, the magnitude of moderate stress cycles and the consequent influence on SCC growth is enhanced by local stress-concentrating features such as seam weld toes, manufacturing grooves, and mechanical surface damage.

Circumferential SCC has occurred in pipelines operating at low hoop stresses due to pressure but subjected to large axial stresses due to external loadings, typically related to soil movement or installation practices. In some cases, the pressures were so low that no effective cycling could be attributed to pressure. At buried pipeline depth, temperatures are typically moderated so thermal stress cycles are likewise small. Thus, stress cycles cannot often be implicated. However, monotonic (intermittent, seasonal, or continual) increase in external load can provide the mechanism for film rupture that facilitates SCC activation or growth.

### A.2.5 Environment

Environment is a primary differentiator between high and low susceptibility circumstances as well as which mode of SCC might occur. However the "environment" encompasses the aggregate or combined effect of a number of operational contributors such as temperature and pressure cycling and external factors related to CP, soil characteristics, drainage patterns, and coating characteristics. Therefore, these factors will be discussed separately in terms of their relationships that promote conducive conditions.

### A.2.6 Electrochemical Conditions



Near-neutral pH SCC occurs at free corrosion electrochemical potentials of –760 mV to –790 mV (copper-copper sulfate) corresponding to an absence of cathodic current at the pipe surface. This is particularly prevalent with disbonded and shielding coatings (e.g. PE tape) and to a lesser extent with older coal tar or asphalt coatings.

High-pH SCC occurs at electrochemical potentials of –600 mV to –750 mV (copper-copper sulfate) corresponding to some cathodic current reaching the pipe. This occurs with mildly shielding coatings such as older coal tar or asphalt or where external conditions contribute to shielding such as rock in contact with the pipe.

The potential levels described above are undercoating conditions that might not be reflected by what is measured as a potential at the ground surface.

### A.2.7 Undercoating Chemistry

Undercoating liquids associated with near-neutral pH SCC are dilute bicarbonate solutions with pH in the range of 5.5 to 7.5. Conditions at the pipe surface are anaerobic but the bulk soil could be aerobic or anaerobic.

Undercoating liquids associated with high-pH SCC are concentrated carbonate-bicarbonate solutions with pH above 9.3. Chlorides might be present. Aerobic conditions are not specific. Coating and cathodic conditions interact to produce these conditions.

### A.2.8 Temperature

Near-neutral pH SCC is nonspecific as to operating temperatures or climatic temperatures. It has been found at all latitudes in North America. High-pH SCC is typically specific to operating temperatures above 32 °C (90 °F). Such temperatures have been associated with the first 30 km (20 miles) downstream of natural gas compressor facilities not equipped with aftercooling (primarily older vintage facilities). It can also occur in liquid lines where increases in throughput result in elevated temperatures, or where soil temperatures are high. Increasing temperature increases the rate of crack growth.

### A.2.9 Coating and Soil

Coating type, in conjunction with soil characteristics consisting of formation attributes (mode of deposition and texture), topography patterns and landscape position in association with drainage conditions, constitutes one of the most important integrated factors to assist in determining SCC susceptibility, particularly for near-neutral pH SCC. These integrated soil characteristics are known within the industry as terrain conditions. The deterministic multi-parameter interaction of coating type and soil characteristics through industry experiences reinforces the difficulty and noncorrelation history of single soil factors between coatings and SCC susceptibility.

Most coatings, such as field-applied plastic or PE tape coatings, heat shrink PE sleeves, asphalt, coal tars, and waxes, when improperly applied during construction or degraded over time can become disbonded, which potentially shield the pipe electrically from the protective nature of the CP system, thus increasing SCC susceptibility. If conditions at the time of installation are nonoptimal, coatings can wrinkle, suffer stone penetration, or simply not adhere to the pipe surface leading to expedited coating deterioration and increased SCC susceptibility.

Double-wrapped PE tape is significantly less susceptible to wrinkling or disbondment than a single wrap. Extruded PE, while inherently shielding of cathodic current from the pipe surface, is generally resistant to disbondment or stone penetration due to its good mechanical toughness and good adherence to the pipe surface. Thus, extruded PE coated pipe is not considered to be susceptible unless tape or shrink sleeves are applied at the girth weld locations. Wax coatings that contain a cellophane backing exhibit shielding tendencies similar to PE coatings and shrink sleeves.

Asphalt and coal tar enamel coatings can partially shield the pipe from CP, but not to the extent of disbonded tape and shrink sleeves. Beyond FBE coating being well adhered to the pipe surface, resistant to mechanical penetration and inherently nonshielding in terms of CP current, the prerequisite abrasive blasting leaves the pipe surface in a state of residual compressive stress. Therefore, FBE-coated surfaces are not susceptible. However, some FBE-coated pipelines have been installed using PE heat shrink wraps at girth welds made in the field, which can be susceptible to SCC. The performance attributes of FBE regarding SCC susceptibility largely apply to the other high integrity coatings such as paint/spray grade epoxies and urethanes.



The influence of terrain characteristics on coating disbondment that can increase SCC susceptibility is based on the integration of soil formation, texture (i.e. grain size), related drainage, and topography. Finer grained textures such as clays and silts in contact with the pipe can seasonally shrink or swell with changes in moisture content, which can contribute to wrinkling and increased disbondment over the lifetime of the pipeline asset. Operating temperatures can also accelerate disbondment and coating continuity (i.e. cracks in the coating) degradation in both coarser and finer grained textures. Another mode of coating deterioration is soils containing stones that can penetrate most coating types developing into either isolated or continuous disbondment patterns. Secondarily, most coatings are pervious to certain soil chemistry elements and gas components. This occurrence can lead to further secondary chemical reactions between the pipe surface and underside of the coating enhancing additional coating disbondment over time.

### A.2.10 Previous SCC

Prior discovery of SCC in a given pipeline segment is a strong indicator of susceptibility. The operator should consider the similarity of operating and environmental parameters, such as soil consistency and coating type, as well as the extent and severity of previously discovered SCC. However, no prior discovery of SCC in a segment of pipeline that otherwise exhibits strong presence of factors that promote susceptibility should not be construed to mean that susceptibility is, in fact, low.

### A.2.11 Presence of Corrosion

High pH is not associated with surface pitting due to the electrochemical potential being in the partially protected range. Near-neutral pH is associated with light surface corrosion due to the absence of cathodic current reaching the pipe surface. Once oxygen levels are consumed, conditions become anaerobic, which would not support significant metal loss due to pitting.

As a result of these traits, the absence of indications (e.g. from ILI) of significant pitting or metal loss due to corrosion, independent of other susceptibility-related data, cannot distinguish low or high susceptibility to SCC. Indications of significant metal loss are a contra-indicator of SCC susceptibility at least locally. However, it is noted that the presence of metal loss can be a useful indicator of the overall condition of the coating and CP in a segment of pipeline and can be useful in conjunction with other susceptibility factors. One situation in which near-neutral pH SCC is associated with pitting arises where the pitting is caused by microbial activity. The environmental conditions that promote near-neutral pH SCC overlap those that support some microbial activity, with the exception of sensitivity to stress level in the case of SCC. Near-neutral pH SCC has been identified in deep pits caused by microbial activity even in pipelines that nominally operate at low stress, where stress levels become elevated above the SCC threshold in the remaining ligament. Moreover, both conditions (MIC and near-neutral pH SCC) can be controllable if cathodic current reaches the pipe surface. Therefore, the occurrence of external MIC could indicate potential susceptibility to near-neutral pH SCC.

### A.2.12 Data

When assessing susceptibility, the operator should consider whether data concerning the factors discussed above are available and reliable. A more conservative approach to gauging susceptibility may be warranted where data are incomplete to offset the possibility that conditions are more adverse than they appear. However, the user is cautioned against making such conservative assumptions that false perceptions of risk are created. The scoring or ranking of susceptibility should be based on data concerning factors discussed above, considering data quality. Where data are incomplete or of questionable accuracy, a plan should be developed to obtain improved data.

NACE SP0204, a standard practice for the SCCDA methodology, Table A-1 therein, presents an extensive list of pipe-related, construction-related, environment-related, corrosion control-related, and operations-related factors. The table describes each factor's relevance to SCC, the use and interpretation of the information, and a subjective importance ranking factor. A simplified interpretation of the relative importance of the NACE ranking factors is reproduced in Table A.1 from Beavers [27]. The table is presented for illustrative purposes only. The interdependence of conditions or factors as they pertain to the attributes of a given pipeline segment should be considered when developing susceptibility scores.



**Table A.1—Simplified Stress Corrosion Cracking Susceptibility Ranking Factors—Illustrative Example (from Beavers [27])**

| Factor | Ranking | |
|---|---|---|
| | High-pH Stress Corrosion Cracking | Near-neutral pH Stress Corrosion Cracking |
| Pipe temperature | A | C |
| Pipeline age | A | A |
| Soil properties | B | A |
| Maximum stress | A | A |
| Stress fluctuations | B | A |
| Stress concentrators | B | A |
| Surface condition | A | A |
| Pipe coating | A | A |
| Girth weld coatings | A | A |
| Pipe manufacturer | C | B |
| Cathodic protection-related parameters | B | B |
| A" indicates a major influence, "B" indicates a factor having some effect, and "C" indicates a minor effect. | | |

Susceptibility scores can be useful for selecting segments for condition assessment based on where the operator believes SCC might be found. They can also be useful for interpreting ILI features and prioritizing excavations based on how likely the operator believes features to be SCC. The rankings should account for the timing of important changes in conditions or operation of the pipeline. For example, a section of line could have at one time been affected by one or more factors strongly indicating susceptibility, such as historic operation downstream of gas compressor facilities without aftercooling or operation for a time with minimal CP, but these SCC-conducive conditions were corrected by facility upgrades. Thus, one could expect to find evidence of old SCC that possibly is no longer active. Additionally, the discovery of no SCC where it was expected or noteworthy SCC where it was not expected should lead to reevaluation of the validity of the susceptibility model and reevaluation of previously ranked segments.

## A.3 Comparison of Reported Crack Growth Rates Obtained from Different Methods

### A.3.1 General

Empirically observed growth rates can provide a reliable method of estimating SCC growth rates. Empirical approaches that have been used to estimate SCC growth rates include laboratory testing under simulated conditions, fractographic examination of test failures or exemplar cutouts, field measurements, or multiple ILI run comparisons. The results from these approaches have been reported in the subject literature and are compared in Table A.2. The purpose of this table is to illustrate the wide range of values that could be inferred. The values presented herein are not purported to represent actual rates that could be effective in any particular situation. These data can enable an operator to evaluate whether his own observations of apparent SCC growth rates are realistic.

**Table A.2—Range of Reported Average Stress Corrosion Cracking Growth Rates**



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

### A.3.2 Laboratory Testing That Simulates Field Conditions

SCC growth rates measured in laboratory tests that attempt to simulate field operating conditions provide a distribution of growth rates ranging from approximately 0.2 e-8 mm/s (0.06 mm or 0.002 in. per year) to 2.8 e-8 mm/s (0.88 mm or 0.035 in. per year). Results from laboratory testing are typically overly conservative compared with apparent growth rates observed in the field. Due to uncertainty as to whether laboratory conditions simulate actual conditions affecting a pipeline site of interest, laboratory crack growth rates should only ever be applied with caution, if at all.

### A.3.3 Fractographic Analysis

The fracture surface of SCC features can be examined microscopically to identify and analyze features possibly tied to past events such as hydrostatic pressure tests that occurred after the SCC initiated. Specimens could be those from service or hydrostatic test failures or selected cutouts that are broken open for study.

Differences in the depth of “beach marks” on the fracture face of an SCC feature can provide an estimate of SCC growth. Beach marks are semielliptical features associated with an interruption of a steady crack-growth process, typically a past hydrostatic pressure test that would have induced crack tip blunting and/or residual stresses that would have temporarily halted the SCC growth process. Beach marks are seen as a bifurcation of the SCC tip in the axial direction.

Reported SCC growth rate measurements determined from operating failures to date relate primarily to depth-wise growth. To date, time-averaged growth rates due to an environmental mechanism observed on an NPS 36 pipeline were $1 \times 10^{-8}$ mm/s (0.3 mm or 0.012 in. per year) and $2 \times 10^{-8}$ mm/s (0.63 mm or 0.025 in. per year). SCC ruptures on NPS 8 and NPS 10 pipelines both resulted from a maximum time-averaged rate of $5 \times 10^{-9}$ mm/s (0.16 mm or 0.006 in. per year). SCC features adjacent to the failures grew at rates of $1 \times 10^{-9}$ mm/s (0.03 mm or 0.001 in. per year) to $4 \times 10^{-9}$ mm/s (0.13 mm or 0.005 in. per year).

### A.3.4 SCC Size Distributions Generated from Field Inspection Data

The largest dataset available to most operators is simply the lengths and depths of SCC detected and sized during pipeline excavations. Length and depth data can be produced by a combination of contrasting magnetic particle examination, advanced UT, and light surface buffing to depth. Accurate measurement of depth by magnetic particle testing alone is very difficult. Although the start point or incubation period is unknown, with sufficient data and growth periods extending into decades, the start point has a decreasing weighting in the calculation of growth. Nonetheless, some additional conservatism should be applied to account for the possibility of underestimating growth due to overestimating the growth period. Assuming the SCC started soon after the pipeline entered service can lead to an unconservatively low estimate of average growth rate. Typical field inspection data suggest average growth rates on of the order of $10^{-9}$ mm/s ($4 \times 10^{-7}$ mils/s). The user should recognize that actual growth rates can be expected to over time depending on its phase of growth as well as interaction with pressure cycles. One important advantage of field inspection data is that they can provide insight to operative rates specific to a pipeline segment or location.

### A.3.5 Multiple SCC ILI Inspections Separated by Several Years



In principle, consecutive ILIs for SCC can provide a large amount of data with respect to growth rates. An inherent limitation is that SCC growth rates can vary significantly over the SCC life cycle. One analysis method involves rigorously matching SCC features identified in repeat tool runs and determining the associated change in depth and length. This raises a second inherent limitation, which is the sizing accuracy of current ILI technology

A second method, which can provide a general understanding of where there is an increasing SCC threat, presents data graphically showing frequency distributions of indicated lengths and depths. By comparing depths or lengths of two inspection runs at the equivalent frequency, growth rate estimates can be estimated as a simple difference. As well, observations of where the growth occurs within the distribution can be made. Similar to hydrotesting, the consecutive ILI inspections must be separated by several years to achieve adequate resolution in growth. No growth rates have yet been published using this technique.

# Annex B
(normative)

## Prioritization for Threats Associated with ERW and EFW Pipe

A number of factors should be considered when prioritizing ERW and EFW pipe. A detailed flowchart is included that provides operators with a tool to conduct this prioritization, taking into account the following factors:

a) type of longitudinal seam,

b) year of manufacture,

c) service or hydrostatic test failure history related to grooving corrosion or fatigue,

d) operating stress level,

e) hydrostatic test pressure levels,

f) coating condition and CP effectiveness,

g) aggressiveness of operational pressure cycles (see TTO Number 5 for guidance on aggressiveness determination).

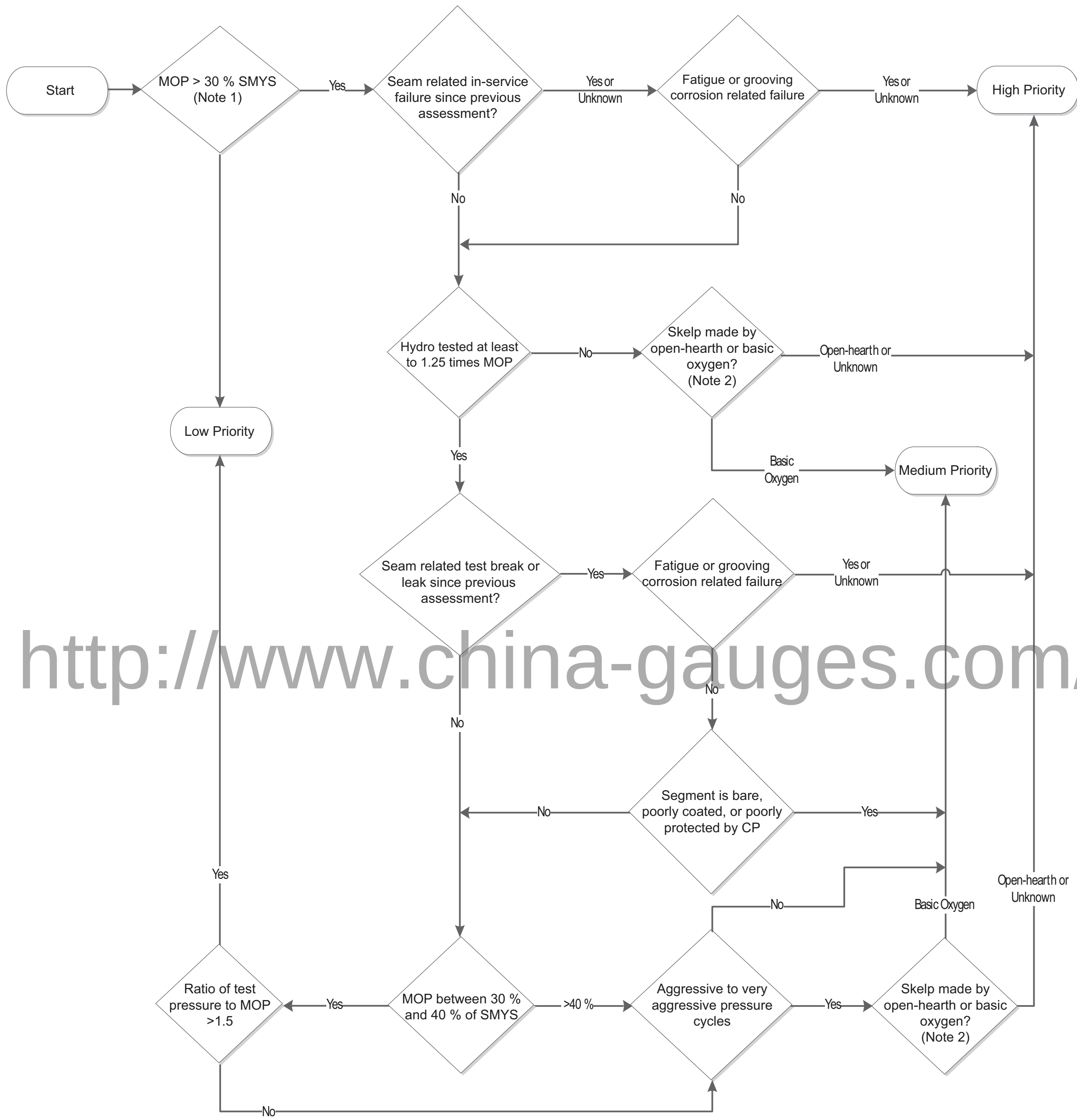
The flowchart (Figure B.1) below will determine a system prioritization of low, medium, or high. Each system is unique and the flowchart should be used to evaluate all risk factors and make integrity decisions accordingly. When significant operational changes occur, operators should reevaluate the prioritization. Additional knowledge on mill inspection requirements can also enable reprioritization. In addition, knowledge of the steel making process, either open-hearth or basic oxygen, can lower the prioritization level as the basic oxygen process reduced the quantities of impurities in the steel that could lead to manufacturing flaws. Historical information [38] is available that can aide in the determination of the steel making process. Guidelines an operator may follow are provided for the three classification levels.



a) *High Priority*—Pipelines where a time-dependent failure mechanism has caused service or test failures and a remaining life of 10 years or less. These are pipeline systems where a remaining life should be determined from ILI data or hydrostatic test pressure levels (see Sections 11 and 12, respectively). Review of inputs to the flowchart and the remaining life calculations should occur at least annually to determine if reassessment decisions require updating.

b) *Medium Priority*—Pipelines where a time-dependent failure mechanism has not been observed but other conditions exist that make a future seam integrity issue more likely. This can be the existence of LF-ERW pipe with no PWHT, or a system that does not have a ratio of test pressure to operating pressure above 1.25. A remaining life should be determined from ILI data or hydrostatic test pressure levels to determine an appropriate reassessment interval (see Section 8). Review of inputs to the flowchart and the remaining life calculations should be done at least every 3 years to determine if reassessment decisions require updating.

c) *Low Priority*—Pipelines where a time-dependent failure mechanism has not been observed and the other conditions are such that a future seam integrity issue is unlikely. Rarely, fatigue crack growth has been documented in a few cases where the pipeline was operating at a low stress level and remaining life calculations have shown that a short life is possible for systems not tested to a very high percent of SMYS. Therefore, it is prudent to evaluate previous ILI or hydrostatic test data and determine a remaining life for systems with a low pressure test. Review of inputs to the flowchart and the remaining life calculations should be done at least every 5 years to determine if reassessment decisions require updating.






NOTE 1 MOP/MAOP greater than 30 % SMYS applies for ductile material or the consideration is for systems operating to pressures that induce a hoop stress greater than 7 ksi for brittle material.

NOTE 2 A basic oxygen process is where excess carbon and other impurities are burnt out of pig iron to produce steel. Compared to previous processes (i.e. open-hearth), its main advantages were that it did not expose the steel to excessive nitrogen, which would cause the steel to become brittle. The process used may be determined from historical records on pipe manufacturers (Kiefner, J.F., and Clark, E.B., "History of Line Pipe Manufacturing in North America," an ASME Research Report, CRTD-Vol. 43, Copyright 1996).

**Figure B.1—System Prioritization Flowchart**

# Annex C
(normative)

## Assessment Methods for Crack-like Flaws

### C.1 General

This annex provides a brief overview of the most common methods for evaluating the FFS of flaws in pipeline long seam welds. Details on these methods are available in the references cited. There are a number of ways in which crack-like flaws can be evaluated, with varying degrees of complexity. It is the responsibility of the analyst to ensure that the methods used are appropriate for the application. It is also important that the assumptions made for critical input parameters are relevant to the pipeline and provide an adequate margin of safety.

### C.2 Battelle Model (Log-secant)

The Battelle model [36], commonly referred to as either the "log-secant" approach or NG-18 equation, is a semi-empirical model developed to predict the burst pressure of longitudinally seam welded pipe with axial oriented surface flaws. It is based on the Dugdale strip-yield model for a through-wall crack and was empirically fit to experimental burst tests.

The common form of the toughness equation [Equation (C.1)] is written in the following manner:

$$\frac{K_c{}^2\pi}{8c\sigma_{\text{flow}}^2} = \frac{(\text{CVN}/A_c)E\pi}{8c\sigma_{\text{flow}}^2} = \ln\left[\sec\left(\frac{\pi M_s\sigma_F}{2\sigma_{\text{flow}}}\right)\right] \tag{C.1}$$



where

$K_c$ is material toughness;

CVN is Charpy impact energy;

$A_c$ is area of Charpy specimen;

$\sigma_F$ is failure stress;

$M_s$ is Folias surface correction factor;

$\sigma_{\text{flow}}$ is flow stress defined as the average of the yield strength and tensile strength;

$c$ is crack length;

$E$ is Young's modulus.

The log-secant equation [Equation (C.2)] can be rearranged to solve for the burst pressure as follows:

$$P_F = \frac{4t\sigma_{\text{flow}}}{\pi D M_s}\cos^{-1}\left[\exp\left(-\frac{(\text{CVN}/A_c)E\pi}{8c\sigma_{\text{flow}}^2}\right)\right] \tag{C.2}$$

where

$t$ is pipe wall thickness;

$D$ is pipe diameter.

This model has been widely applied since its original development in the 1970s. In many cases, it has been found to provide reasonably good predictions of burst pressure when failure is controlled by plastic collapse. In some instances, however, the model has been found to be overly conservative in predicting burst pressure, particularly for long shallow flaws. A modification of the original model [40] was developed to account for this, having the following form to calculate burst pressure [Equation (C.3)]:

$$P_{\mathrm{F}} = \frac{4t\sigma_{\mathrm{flow}}}{\pi D M_{\mathrm{s}}} \frac{\cos^{-1}[\exp(-X)]}{\cos^{-1}[\exp(-Y)]} \tag{C.3}$$

where

$$X = \frac{(\mathrm{CVN}/A_{\mathrm{c}})E\pi}{8c\sigma_{\mathrm{flow}}^{2}}$$

$$Y = X[1-(d/t)^{0.8}]^{-1}$$

This modified form of the log-secant model addresses some of the limitations of the original equation and generally provides a closer correlation to burst test data where the failure mode is controlled by plastic collapse. However, the model might not be appropriate for all circumstances and in some cases can provide nonconservative results, particularly for pipe with CVN values less than 10 J (15 ft-lb).

## C.3 CorLAS™ Model

A number of proprietary tools have been applied to the assessment of crack-like flaws in pipelines. The most widely used tool is known as CorLAS™. This approach incorporates a "two criteria" model for flaw assessment that considers both a flow-strength criterion for plastic collapse as well as a toughness criterion. The CorLAS™ model written in terms of burst pressure [Equation (C.4)] is as follows:



$$P_{\mathrm{F}} = \sigma_{\mathrm{crit}}\left[\frac{1-\frac{\pi a}{4t}}{1-\frac{\pi a}{4tM}}\right] \tag{C.4}$$

where

$a$ is the crack depth;

$t$ is the wall thickness;

$M$ is the Folias factor;

$\sigma_{\mathrm{crit}} = \min(\sigma_{\mathrm{flow}}\sigma_{\mathrm{T}})$.

where

$\sigma_{\mathrm{flow}}$ is the flow stress defined as the average of the yield strength and tensile strength;

$\sigma_{\mathrm{T}}$ is the failure stress defined using a toughness criterion (references).

To determine $\sigma_{\mathrm{T}}$, the driving force for fracture is calculated based on elastic-plastic fracture mechanics concepts using the $J$ integral. This driving force is then compared with the critical toughness value defined by $J_{\mathrm{IC}}$ for the pipe, where $J_{IC}$ represents the onset of stable crack growth as determined from a fracture mechanics test. The $J$ integral is calculated as the sum of elastic ($J_e$) and plastic ($J_p$) components [Equation (C.5)]:

$$J = J_e + J_p \tag{C.5}$$

where

$$J_e = \frac{Q_f F_{sf} a \sigma^2 \pi}{E}$$

$$J_p = Q_f F_{sf} a f_3(n) \varepsilon_p \sigma$$

The terms are defined as follows:

$Q_f$ is a flaw shape factor;

$F_{sf}$ is a free surface correction factor;

$a$ is the crack depth;

$f_3(n)$ is a factor accounting for strain hardening;

$\varepsilon_p$ is the local plastic strain;

$E$ is the modulus of elasticity;

$\sigma$ is the local stress that includes the Folias factor.



Ideally, the calculated value of $J$ (driving force) would be compared to an experimentally determined value for $J_{IC}$. However, as data for $J_{IC}$ are typically not available, it is can be estimated using a suitable correlation to Charpy data.

## C.4 API 579-1/ASME FFS-1

API 579-1/ASME FFS-1, Part 9 provides approaches to assessing crack-like flaws in pressure-containing equipment using a FAD. It provides three levels of assessment. Level 1 requires minimal data and is designed to be conservative, useful for screening purposes. The Level 2 assessment provides somewhat less conservatism, but involves some analysis as well as more detailed information about materials properties and flaw characteristics. In most cases, the Level 2 approach is the most appropriate approach for pipeline applications. The Level 3 procedure is the least conservative and uses advanced analysis techniques and models, as well as detailed information on materials properties and flaw characterization. This advanced Level is generally applicable for evaluation of flaws associated with complex stress patterns, e.g. near nozzles or other geometric discontinuities.

The FAD is used in API 579-1/ASME FFS-1 to evaluate the stability of flaws with failure modes that range from brittle fracture to plastic collapse, as well as behavior between these two extremes. The FAD defines the failure condition in terms of a toughness ratio ($K_r$) and load ratio ($L_r$) as shown in Figure C.1. The boundary condition is defined by a relationship between $K_r$ and $L_r$, derived such that the dependency on flaw geometry is eliminated. Assessment points that lie inside the curve are considered acceptable, while points that lie outside the curve are considered unacceptable.

The toughness ratio is defined as [Equation (C.6)]:

$$K_r = \frac{K_I}{K_{mat}} \tag{C.6}$$

where

$K_I$ is the applied stress intensity factor;

$K_{mat}$ is the material toughness.

The load ratio is defined as [Equation (C.7)]:

$$L_r = \frac{\sigma_{ref}}{\sigma_y} \tag{C.7}$$

where

$\sigma_{ref}$ is the reference stress;

$\sigma_y$ is the yield strength of the material.

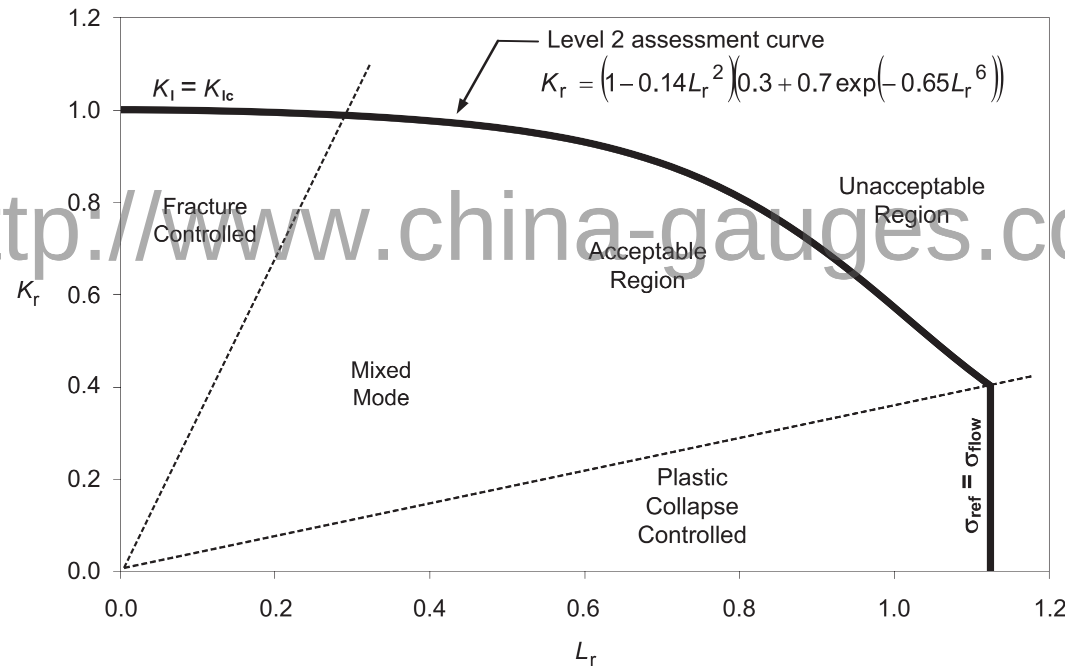




**Figure C.1—Definition of Failure Condition in Terms of Toughness Ratio ($K_r$) and Load Ratio ($L_r$)**

For the given application, values for $K_r$ and $L_r$ are calculated and plotted on the FAD to determine if the flaw is acceptable. The safety margin associated with the result can be estimated in a straightforward manner by observing the proximity of the plotted point to the FAD boundary.

Stress is the final input parameter required for a FFS assessment. As noted above, stress due to operating pressure acting on an axially oriented flaw (hoop stress) is straightforward to calculate. For flaws located within close proximity to some structural discontinuity, a detailed analysis could be required. Another final consideration in estimating the stress acting on a flaw is the effects of welding. Generally, pipe that has been fabricated using autogenous welding process (e.g. ERW) and has been heat treated following fabrication or has been cold expanded will have low residual welding stress that does not need to be accounted for in an analysis. In absence of these, assuming a nominal value of approximately 35 MPa (5 ksi) in these cases can be appropriate for calculation of the stress intensity. Pipeline welds made with filler metal (e.g. SAW, DSAW, etc.) can produce higher residual stresses if they have not been heat treated. Guidance for estimating weld residual stress for heat treated as well as non-heat-treated welds is provided in some FFS standards such as API 579-1/ASME FFS-1, Annex E or BS 7910, Annex Q. A final consideration is the effect of residual stress created during the manufacturing process associated with forming (rolling) the plate into a cylinder and clamping in place prior to welding. This effect can usually be ignored unless some evidence of springback has been observed during maintenance work involving sectioning the line or following a failure where significant displacement has been observed between the crack faces. In these cases, assuming a secondary stress in the range of about 100 MPa (15 ksi) can be appropriate.

## C.5 Validation of Methods for Evaluation of SCC

A recent compilation of burst test data from SCC defects [32] (JIP2 study) provided the opportunity to compare the abilities of the various relationships for critical defect size to predict the failure pressure of affected pipe.

Overall, 86 test cases were available: 15 in-service failures, 47 hydrostatic test failures, and 24 pipe burst tests. Of these, 38 had enough detail about the shape of the crack and the mechanical properties of the pipe to be used for this analysis. Within the database, the failure-initiating SCC flaws had widely differing crack profiles. Some single flaws closely resembled an elliptical profile, whereas other single flaws had double or multiple peaks. Other flaws consisted of two or more separate individual cracks, either on a single radial-axial plane or on multiple radial-axial planes within a three-dimensional cluster.

Failure pressures for each well-documented case were calculated using three widely used methods for assessing axial flaws: the Modified Ln-secant method, CorLAS™, and API 579-1/ASME FFS-1, Level 2. All the methods gave broadly similar results for single flaws with simple profiles. However, the scatter in predicted failure pressure increased when single flaws had a complex profile and increased even further for flaws containing closely spaced pairs or clusters of cracks. All the methods generally gave rise to conservative predictions; methods that simply used maximum flaw depth and overall flaw length were the most conservative, sometimes excessively so, for the flaws with most complex shape. The Ln-secant and CorLAS™ methods seemed to be better overall than API 579-1/ASME FFS-1, Level 2. Conservatism could in part be a result of residual strength in narrow ligaments between closely adjacent but unconnected individual cracks within the complex crack arrays, an affect not accounted for in the models.



Independent of the JIP2 study, the same data were evaluated by combining an effective area approach (similar to what is employed with the Effective Area Method or "RSTRENG Method" for evaluating complex corrosion metal-loss profiles) with the Modified Ln-secant equation. This approach produced slightly better correlation and reduced scatter relative to the basic methods described above. Such an approach might offer benefit where ILI or NDE data are capable of indicating complex depth profiles.

# Annex D
(informative)

# Yield Strength and Tensile Strength

Pipe material properties can be determined from MTRs where available. MTRs typically report transverse and/or longitudinal yield strength and tensile strength for pipe body and seam, Charpy impact absorbed energy and shear appearance (SA), one or more test temperatures, and chemistry, on a per heat basis. The MTR can also report supplementary data not required by the pipe product specification for information.

MTRs might not be available for some pipelines of interest. In lieu of such data, the values reported in Table D.1 and Figure D.1 for yield strengths and Table D.2 and Figure D.2 for ultimate tensile strengths may be used. These values are based on several hundred tests performed on material samples covering a broad range of grades, vintages, and sources. Alternatively, a user may refer to another database that is applicable to the pipe of interest. An operator may also use sample testing to confirm properties; however, a limited sample size might not be adequate to establish the full range of values.

**Table D.1—Database Yield Strength (YS) Properties by Grade**

| **Grade** | **SMYS** lb/in.$^2$ (MPa) | **Mean YS** lb/in.$^2$ (MPa) | **StdDev** lb/in.$^2$ (MPa) | **SD/Mean** | **U95 YS = AvgYS+1.64sd** lb/in.$^2$ (MPa) | **L5 S = AvgYS–1.64sd** lb/in.$^2$ (MPa) |
|---|---|---|---|---|---|---|
| A/Bsmr/OH | 30,000 (210) [a] | 39,997 (275.77) | 4,535 (31.267) | 0.113 | 47,434 (327.04) | 32,560 (224.49) |
| B | 35,000 (245) | 48,641 (335.37) | 7,795 (53.744) | 0.160 | 61,425 (423.51) | 35,857 (247.22) |
| X42 | 42,000 (290) | 52,228 (360.1) | 6,396 (44.09) | 0.122 | 62,717 (432.42) | 41,739 (287.78) |
| X46 | 46,000 (320) | 53,723 (301.46) | 5,963 (39.25) | 0.111 | 63,502 (437.83) | 43,944 (302.98) |
| X52 | 52,000 (360) | 59,192 (408.11) | 5,983 (41.25) | 0.101 | 69,004 (475.77) | 49,380 (340.46) |
| X56 | 56,000 (390) | 62,833 (433.22) | 8,704 (60.01) | 0.139 | 77,108 (531.64) | 48,558 (334.79) |
| X60 | 60,000 (415) | 68,660 (473.39) | 5,390 (37.16) | 0.079 | 77,500 (534.34) | 59,820 (412.44) |
| X65 | 65,000 (450) | 72,003 (496.44) | 2,884 (19.88) | 0.040 | 76,733 (592.05) | 67,273 (463.83) |
| X70 | 70,000 (485) | 80,438 (554.60) | 4,996 (34.45) | 0.062 | 88,631 (611.09) | 72,245 (498.11) |

[a] Actual range was YS = 25 ksi to 30 ksi (172 MPa to 207 MPa), UTS = 45 ksi to 50 ksi (210 MPa to 345 MPa).



Figure D.1 presents results from Table D.1.

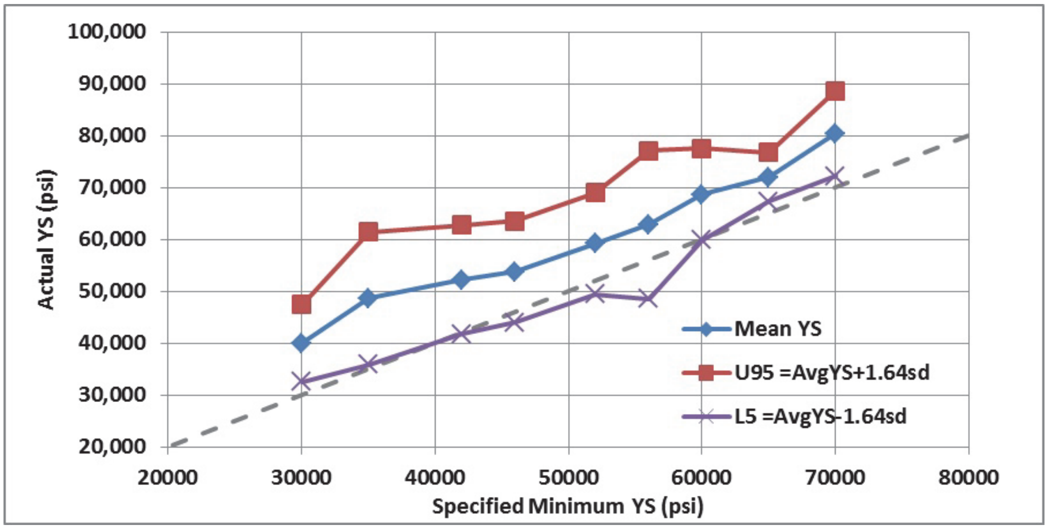



**Figure D.1—Database Yield Strength Properties by Grade**

**Table D.2—Database Tensile Strength (TS) Properties by Grade**

| **Grade** | **SMTS** lb/in.$^2$ (MPa) | **Mean** lb/in.$^2$ (MPa) | **StdDev** lb/in.$^2$ (MPa) | **SD/Mean** | **U95 TS = AvgTS+1.64sd** lb/in.$^2$ (MPa) | **L5 TS = AvgTS–1.64sd** lb/in.$^2$ (MPa) |
|---|---|---|---|---|---|---|
| A/Bsmr/OH | 50,000 (345) | 55,711 (384.11) | 5,266 (36.31) | 0.095 | 64,347 (443.66) | 47,075 (324.57) |
| B | 60,000 (415) | 68,551 (472.64) | 7,062 (48.69) | 0.103 | 80,133 (552.50) | 56,969 (392.79) |
| X42 | 60,000 (415) | 70,533 (486.31) | 5,091 (35.10) | 0.072 | 78,882 (543.87) | 62,184 (428.74) |
| X46 | 63,000 (435) | 73,117 (504.12) | 6,312 (43.52) | 0.086 | 83,469 (575.50) | 62,765 (432.75) |
| X52 | 66,000 (460) | 78,688 (542.53) | 8,698 (59.97) | 0.111 | 92,953 (640.89) | 64,423 (444.18) |
| X56 | 71,000 (490) | 85,083 (586.62) | 7,304 (50.36) | 0.086 | 97,062 (669.22) | 73,104 (504.03) |
| X60 | 75,000 (520) | 86,598 (597.07) | 6,644 (45.81) | 0.077 | 97,494 (672.20) | 75,702 (521.95) |
| X65 | 77,000 (535) | 89,424 (616.56) | 5,915 (40.78) | 0.066 | 99,125 (683.44) | 79,723 (549.67) |
| X70 | 82,000 (570) | 96,125 (628.28) | 5,786 (39.89) | 0.060 | 105,614 (728.18) | 86,636 (597.33) |



Figure D.2 presents the results from Table D.2.

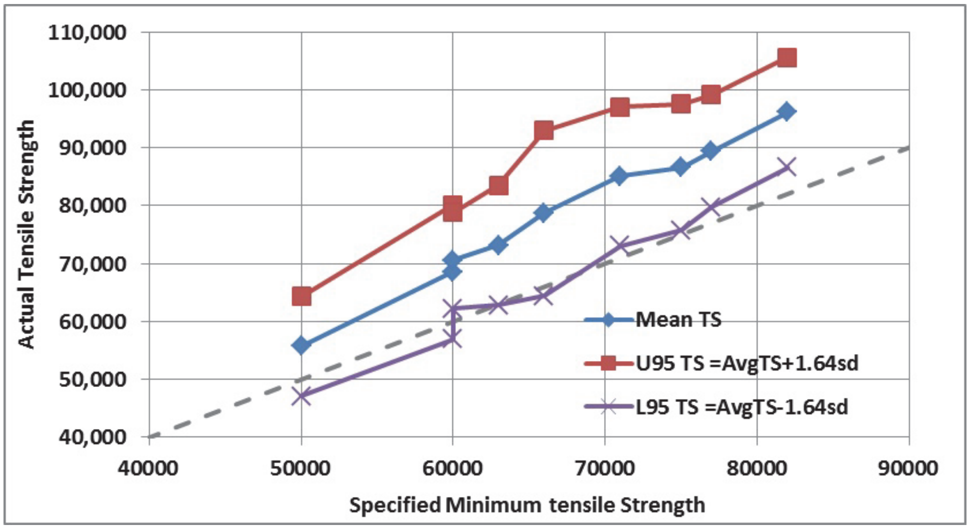



**Figure D.2—Tensile Strength Properties by Grade**

# Annex E
(informative)

# Toughness

## E.1 Toughness Properties for Vintage ERW Pipe

This section provides an overview of toughness data for use in an analysis as well as guidance for how it is used in a seam crack assessment.

Where specific toughness data are not available, the values in Figure E.1 may be used in the analysis. They are derived from a rather extensive dataset developed as part of a PHMSA study [14]. The dataset provided a wide range of CVN transition curves taken from vintage ERW pipelines, many associated with the bondline and weld HAZ region. The data were analyzed statistically to derive a probability plot based on a Wiebull distribution that can be used to identify a toughness value at a target probability level.

The Charpy values are converted to toughness using a typical transition region equation (Sailors-Corten) and then plotted as a three parameter Weibull distribution (procedure outline by Anderson and Stienstra [23]) with a shape factor of 4. The threshold or lower shelf toughness of about 22 MPa $(m)^{0.5}$ [20 ksi $(in.)^{0.5}$] or about 2.7 J to 4 J (2 ft-lb to 3 ft-lb) was used for $\theta_0$, and a value of 41 J (30 ft-lb) was used for $\theta_K$ (red curve). The value for $\theta_K$ was inferred from the Charpy data at 50 °F from the transition curves, which showed an average value of about 13.5 J to 16.2 J (10 ft-lb to 12 ft-lb) or 989 MPa $(m)^{0.5}$ [45 ksi $(in.)^{0.5}$]. This toughness roughly falls at about a probability of 0.5 in the plot when using these assumptions. Various sensitivity cases for $\theta_K$ are shown in the chart. $K_{1c}$ is the critical stress intensity for fracture for mode I loading.



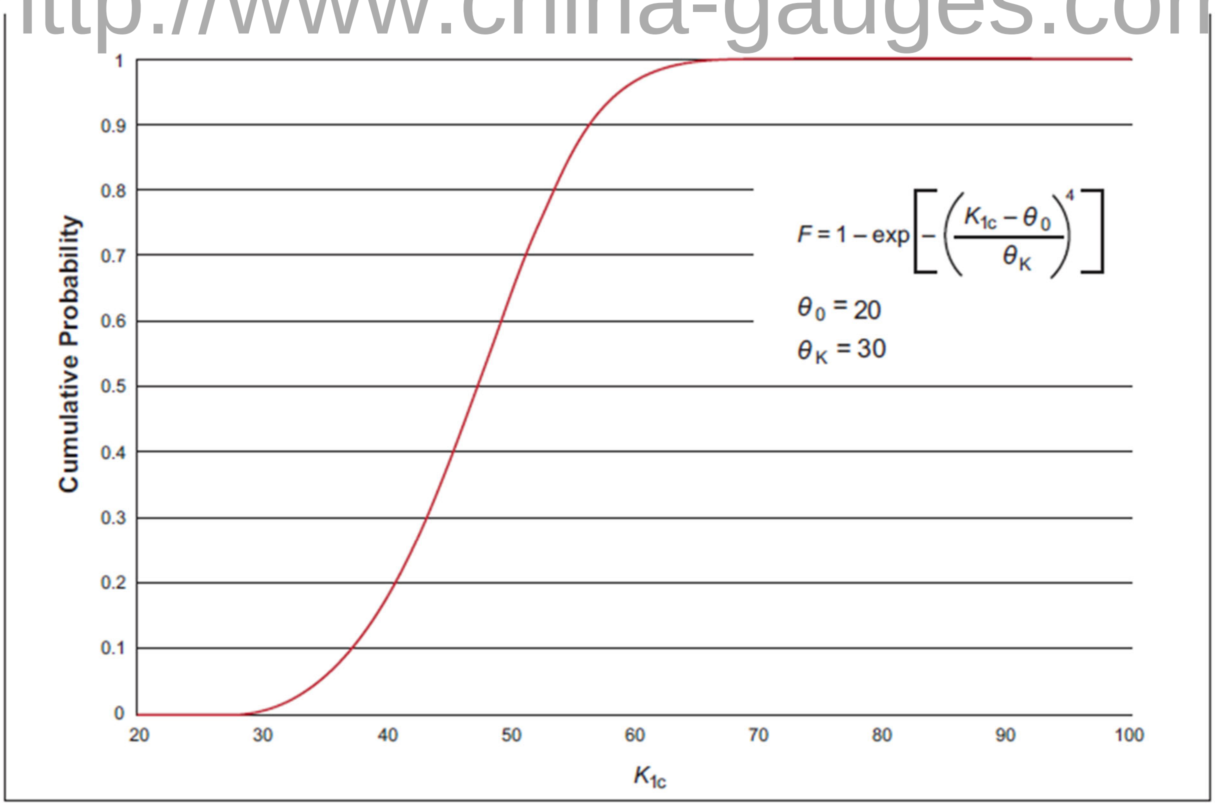



**Figure E.1—Toughness Properties for Vintage Electric Resistance Welding Pipe**

## E.2 Toughness Correlation to Charpy V-notch Impact Data

In most cases, toughness data are not be available on a given pipe. However, in many cases, CVN data are available either from the line in question or historical information about anticipated CVN values available in the literature. To make fracture mechanics calculations regarding tolerable flaw sizes, actual toughness values in the form of $K_{mat}$ are needed. There are a number of correlations that exist to convert CVN data to toughness, often associated with a specific region of the Charpy transition curve; i.e. lower shelf, transition region, and upper shelf. Many of these correlations can be found in API 579-1/ASME FFS-1, Annex F.

## E.3 Toughness and Charpy V-notch Impact Testing

Toughness is a property that quantifies the material's resistance to failure in the presence of a crack or crack-like imperfection when subject to an external load. The Charpy test is a dynamic experiment and as such measured the energy required to fracture a specimen at very high strain rate. A true fracture toughness test, on the other hand, is typically loaded in a quasi-static manner at a low strain rate and provides a measure of the materials resistance to stable crack propagation as a function of applied load. Even though the two test methods are quite different, it is possible to use CVN test data to provide a rough estimate of fracture toughness. The topic of fracture toughness is quite complicated, and not within the scope of this RP.

In general, measurement of fracture toughness from pipe samples provides the best data as input for a FFS assessment. Nevertheless, due to the thin wall thickness and in some cases small pipe diameter, it is necessary to extract nonstandard dimensions compared with the ASTM test requirements. Specimen geometries must be designed with some care to measure toughness properties indicative of the bondline and HAZ of an ERW weld. In particular, orientation of the specimen and placement of the notch is critical in this regard, and special procedures are often required. This holds true for CVN specimens as well. Therefore, when planning mechanical tests on ERW pipe, detailed guidance is required for machining and preparing the specimens as well as steps such as etching test specimens to ensure the notch location is placed in the desired orientation.



Table E.1 shows the typical ASTM tests used to measure both Charpy and fracture toughness.

**Table E.1—Basic Fracture Toughness Properties and Tests**

| Mode | Test | Standards | Property | Application |
|---|---|---|---|---|
| Static | J-resistance (J-R) curve | ASTM E1820<br>ASTM E813<br>ASTM E1737 | Elastic-plastic fracture toughness $J_{IC}$ | Failure assessment diagram (FAD) per API 579-1/ASME FFS-1 |
| | Crack tip opening displacement (CTOD) | ASTM E1820<br>ASTM E1290<br>BS 7448<br>ISO 15653 | Fracture initiation resistance, ductility | Girth weld engineering critical assessment (ECA) per API 1104, Annex A |
| Dynamic | Charpy V-notch impact (CVN) | ASTM A370<br>ASTM E23<br>ISO 148-1 | Fracture propagation resistance; absorbed impact energy and fracture surface shear appearance | Pipe manufacturing quality control per API 5L; fracture control plan, critical flaw size evaluation |
| | Drop weight tear test (DWT) | ASTM E436<br>API 5L3 | Full-scale transition temperature, ductility based on fracture surface shear appearance | Fracture control plan |

## E.4 Transition Behavior

All varieties and grades of carbon steel and high-strength low-alloy (HSLA) steel used in line pipe exhibit a variation in toughness with temperature. If the toughness of a given material is tested over a wide range of temperature, the toughness will be seen to be low at relatively cold temperatures and increase to a plateau value at relatively warm temperatures. Low-toughness conditions are characterized by predominately brittle or cleavage modes of fracture, which propagate with relatively little energy. High-toughness conditions are characterized by predominately ductile shear or tearing modes of fracture, which require higher amounts of energy to propagate through the material. Figure E.2 illustrates these effects.

The transition temperature and the maximum toughness attainable by the material when it is fully ductile are both determined primarily by microstructure, which is itself a product of steel chemistry, thermal processing, and strain history. Generally, a low transition temperature and high ductile toughness are desirable, but material performance requirements are not the same for all pipelines due to differing operating stress levels and operating temperatures. Most line pipe steels manufactured before the 1970s and even for some time afterward did not consider fracture toughness properties in the material specifications. Factors that promote favorable toughness properties are listed in Table E.2. The process route for steel production and the subsequent skelp or slab rolling schedule greatly influence the nature of these factors in any particular pipe.

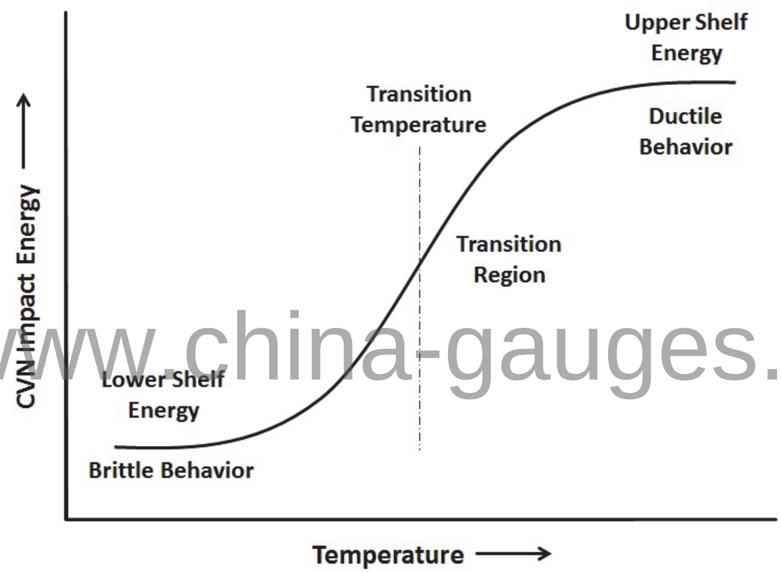





**Figure E.2—Schematic Toughness Transition Curve (from Rolfe and Barsom, 1977)**

As implied by Figure E.2 the transition occurs over a temperature range and is not a distinct value. Several conventions exist for defining the transition temperature. One is the shear appearance transition temperature (SATT) which is the temperature corresponding to 50 % SA in a CVN impact test. Another definition is the temperature corresponding to 85 % SA in the DWT test, which corresponds approximately to the lowest temperature at which full ductile fracture propagation resistance occurs. Specifying this to be below the lowest operating temperature is a modern pipeline design target.

**Table E.2—Factors Promoting Favorable Toughness Properties in Steel Line Pipe**

| Factors Promoting Higher Toughness | Factors Promoting Lower Transition Temperature |
|---|---|
| Fine grained ferrite-pearlite microstructure | Fine grained ferrite-pearlite microstructure |
| Absence of hard microstructure phases | Low carbon content (<0.15 %) |
| Very low sulfur or phosphorus content (<0.015 %) | Low nitrogen and silicon content |
| Low oxide and sulphide inclusion content | Subgrain structure and texture |

## E.5 Initiation versus Propagation

The transition temperature is strongly affected by strain rate. Fracture resistance measured at low strain rates will exhibit a significantly lower transition temperature than fracture properties measured at high strain rates. This effect is indicated in Figure E.3. Strain rates above 10/s are considered dynamic; strain rates on the order of $10^{-3}$/s are considered intermediate; and strain rates below $10^{-5}$/s are considered slow or quasi-static. [27]

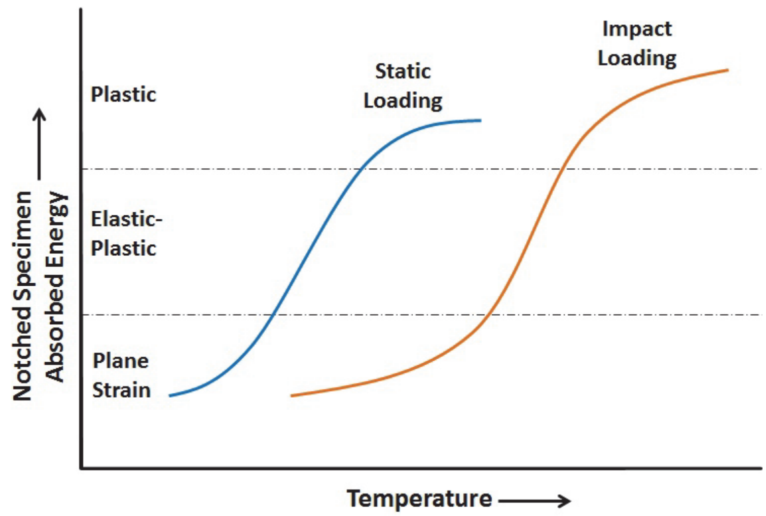



**Figure E.3—Shift in Transition Temperature with Strain Rate**



When a surface defect in a pressurized pipe fails, the fracture extends radially in a quasi-static manner until the remaining ligament fails, resulting in a through-wall defect. The initiation process is governed by the fracture characteristics associated with slow loading. The resulting through-wall crack begins to extend lengthwise at an accelerating rate under the applied pressure or other loading and propagates along the pipe at the acoustic velocity of the steel. The final fracture and subsequent propagation occurs at a high strain rate and is governed by the fracture characteristics associated with dynamic loading.

The shift in transition temperature between initiation and propagation has been observed to be at least 15 °C (60 °F) [42] and could exceed 93 °C (200 °F). [54] [55] Lower strength materials exhibit the widest spread between fracture initiation and propagation transition temperatures. This spread between the fracture initiation transition temperature (FITT) and fracture propagation transition temperature (FPTT) can be approximated on average from the yield strength as $\Delta T$ = 215 – 1.5(SY) in units of degrees Fahrenheit and yield strength in ksi. [45] The significance of this behavior is that pipe having a FPTT well above the operating temperature as indicated by the CVN impact test can still initiate a fracture in a ductile manner. However, once the fracture becomes through-wall and the length extends dynamically under the influence of hoop stress, its propagation could occur in a brittle manner. In fact, with only a few specific exceptions, the ductile upper shelf toughness should typically be used with integrity assessments. The exceptions are as follows:

— older vintage LF-ERW seams that have not been PWHT, which are generally limited to pipe produced before API 5L required PWHT to eliminate hard microstructures in 1964;

— casing or tubular goods used as line pipe, an outmoded practice limited to early decades of the pipeline industry;

— pipe affected by unique environmental mechanisms of embrittlement such as hard spots in the body of some types of pipe manufactured in the 1950s.

In the case of a longitudinal fracture in a pressurized pipeline, if the material has high resistance to fracture propagation, it will absorb energy through tearing and slow the fracture velocity to less than the velocity of the decompression wave in the pressurized fluid, and the fracture will arrest in a short distance. [42] If the resistance to fracture propagation is low, the fracture could extend quite far depending on the depressurization characteristics of the contained fluid. Pressurized gases release significant stored energy upon decompression as do supercritical fluids [e.g. carbon dioxide ($CO_2$)] or high vapor pressure liquids upon changing phase due to depressurization. The decompression velocity of such products could be well below the acoustic velocity of the steel, such that a high pressure could persist at the tip of the propagating longitudinal fracture. Pipelines transporting such products require high material toughness to arrest a fracture. Pressurized liquids release little energy upon decompression and generally exhibit high decompression velocities. Thus, pipelines transporting petroleum or liquid refined products usually require relatively modest toughness.

## E.6 Measuring Toughness

Several measures of fracture toughness exist. Each measure is suited for differing purposes and falls into two main groups: static or dynamic. The most commonly performed tests are listed in Table E.2 and are discussed briefly below.

The property $J_{IC}$ is a critical value of the material J-integral fracture toughness. It characterizes the elastic-plastic fracture toughness at the onset of crack growth prior to the onset of significant stable crack extension by ductile tearing. It is measured using one of several configurations of compact tension (CT) coupon containing a fatigue pre-cracked notch. The critical value of J-integral toughness is determined from a graphical analysis of the J-resistance or J-R curve, which is a plot of crack extension resistance as a function of stable crack extension measured from the CT specimen under quasi-static loading. The units for $J$ are energy/area, e.g. in.-lb/in.$^2$ or kJ/m$^2$.

The crack tip opening displacement ($\delta$ or CTOD) is a measure of resistance to crack initiation, determined at or near the onset of stable or unstable crack extension. The CTOD can be determined using a CT coupon similar to what is used to develop the J-R curve; however, for girth weld ECA in accordance with API 1104, Annex A, the coupon is a notched and fatigue pre-cracked bar loaded in three-point bending under quasi-static conditions. The CTOD is measured as the displacement at the mouth of the notch and is related geometrically to the opening at the tip of the crack. This type of test is used with girth weld fracture mechanics analysis because girth welds are most susceptible to failure due to high axial loadings acting on welding workmanship flaws, and such loadings are generally static. The units for $\delta$ are inches or millimeters.



The CVN absorbed impact energy is a measure of resistance to fracture propagation and, when used in a relationship between flaw size and failure stress in a pressurized pipe, fracture initiation as well. Fracture propagation is a dynamic condition and must be measured by a dynamic test; e.g. impact testing. The standard full-size coupon is a rectangular bar 10 mm × 10 mm (0.39 in. × 0.39 in.) in cross section with a 2 mm (78 mil) deep notch. If the pipe wall is not of sufficient thickness to prepare a standard full-size coupon, standard subsized coupons having narrower width can be used. The CVN coupon is impact loaded in three-point bending on the side opposite the notch by a calibrated mass on a swing arm imparting up to 300 J (220 ft-lb) impact capacity. The impact toughness is measured by the amount of kinetic energy absorbed in breaking the coupon, which is indicated from the angle of follow-through of the swing arm after impact. The fracture surfaces of the broken coupon are also examined to determine the ductility as indicated by the percentage shear appearance (% SA) on the fracture surface. The % SA value increases in almost direct proportion with the increase in absorbed energy relative to the upper shelf. The CVN test is perhaps the most common toughness test performed. Its low cost and convenience compared with other toughness test methods lends it to production-scale testing for product quality control at the pipe mill, as well as routine testing in any materials testing service.

The DWT test is a large flattened transverse bar of thickness equal to the full pipe wall thickness and having a pressed or machined notch of straight or chevron profile. The coupon is impacted at the specified minimum operating temperature so as to initiate tearing from the notch. The DWT test is used to confirm the ductility based on % SA in the full-scale material thickness, in order to avoid the specimen size effect that can occur with CVN specimens that are smaller than approximately two-thirds of the pipe metal thickness (discussed below).

## E.7 Specimen Size Effects in CVN Testing

The standard full-size CVN specimen is 10 mm (0.394 in.) wide. Line pipe is often thinner-wall than this dimension, for which standard subsized CVN specimens must be used. A half-size specimen has a width of 5 mm (0.2 in.), for example. The CVN specimen size affects the test result in two ways. One is that it takes less energy to break a smaller specimen. The upper-shelf (upper plateau) impact energy is directly proportional to the specimen width, so 27 J (20 ft-lb) absorbed energy from a two-third-size (6.67 mm) specimen is equivalent to 40 J (30 ft-lb) absorbed energy from a full-size specimen. This is indicated schematically in Figure E.4.

A second, more subtle effect of specimen size is that it affects ductility, which manifests itself as a shift in transition temperature. Specifically, subsize specimens will exhibit a lower transition temperature than full-size specimens; similarly, any size specimen can exhibit a lower transition temperature than the full-scale metal thickness if there is a significant disparity in thickness. The reason for this is constrained plasticity at the tip of the V-notch. A bar of uniform thickness, when strained axially, will contract laterally uniformly in accordance with the Poisson effect. If the bar is notched, the axial strain will localize at the notch; however, Poisson contraction will be constrained due to the thicker, lower-strained material adjacent to the notch. The constrained plastic flow causes the material to exhibit lower ductility. Extending this condition to the CVN, the material at the tip of the notch at mid-thickness is closer to a free surface where plastic flow can occur if the CVN coupon is a thin subsize specimen than if it is a standard full-size coupon. Thus, the thinner specimen will exhibit ductility at lower temperatures than a larger specimen. This effect is also indicated in Figure E.2. The significance of this phenomenon is that if the CVN coupon is smaller than approximately two-thirds of the full-scale pipe wall thickness, it will produce misleading results about the material ductility in the full scale, specifically by indicating better low-temperature ductility than the pipe.

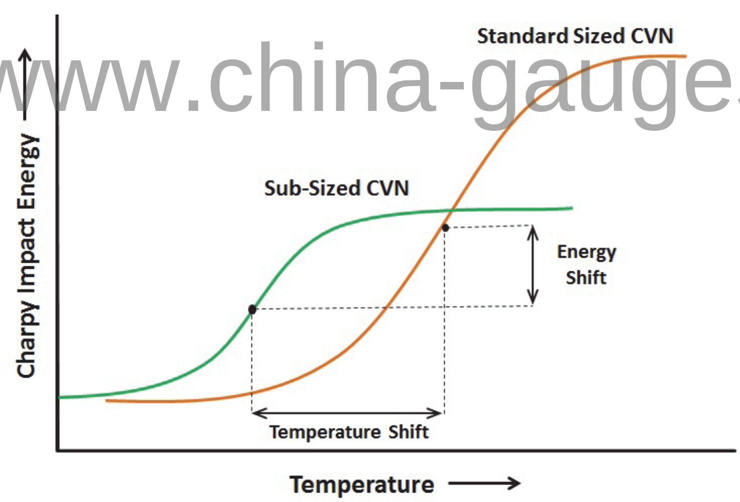





**Figure E.4—Effect of Charpy V-notch Specimen Size on Toughness Transition Curve**

One way to deal with this circumstance is to perform the CVN specimen for measuring the upper shelf only, which can be correlated to the fracture arrest criterion, and perform DWT testing to determine the ductility at the lowest operating temperature. The DWT specimen is not affected by a “size effect” because the coupon thickness is the full-scale pipe wall thickness.

The alternative is to apply one of several empirical relationships that account for the size effect to adjust transition temperatures obtained from CVN specimens smaller than approximately two-thirds of the pipe wall thickness so as to estimate realistic full-scale transition temperature. One simple adjustment is given as follows [46]:

$$T_D = T_C + \Delta T_{size},\ \Delta T_{size} = 66(t_w)^{0.55}/(t_{CVN})^{0.7} \quad \text{(E.1)}$$

where

$T_D$ is the minimum design temperature in °F;

$T_C$ is the transition temperature indicated by the CVN test in °F;

$\Delta T_{size}$ indicates the shift in transition temperature due to the specimen size effect in °F;

$t_w$ is the pipe wall thickness in inches;

$t_{CVN}$ is the CVN coupon width in inches.

One restriction is the $\Delta T_{size}$ less than or equal to 0. This empirical expression was based on observed behavior from testing of line pipe. [43] Other methods for accounting for the specimen size effect are also available. [26]

## E.8 Optimal Toughness

Fracture mechanics assessment relationships between flaw size and failure stress level in pressurized pipe, including API 579-1/ASME FFS-1 FAD, NG-18 Ln-secant and Modified Ln-secant equations, and CorLAS™, generally indicate that a limiting toughness level is reached beyond which no further improvement in failure pressure occurs with increased toughness level. This level is the "optimal toughness." If the actual toughness exceeds the optimal toughness level, the failure is controlled by the material ductile strength; e.g. the flow stress [6] or perhaps the ultimate strength. The optimal toughness often falls in the range of 27 J to 81 J (20 ft-lb to 60 ft-lb), depending on pipe size and operating stress.

## E.9 Sampling and Scatter



The transition curves presented schematically imply smoothly varying behavior, which is not usually the case with any fracture toughness properties testing. All toughness test methods exhibit considerable scatter, particularly in the transitional zone between nearly fully brittle and nearly fully ductile. Many applicable testing standards require three tests for each test temperature or test coupon location around the pipe. Curve fitting could involve statistical best-fit procedures.

Obtaining representative toughness tests for the bondline of older vintage ERW seams can be a challenge due to the extreme narrowness of the bondline. Several test attempts might be necessary. It is not uncommon to observe high or low absorbed energy outliers due to sensitivity to notch placement with respect to the bondline in older vintage ERW pipe if the bondline is inherently low toughness.

[6] The flow stress is a notional stress at the tip of a crack in a ductile material capable of strain hardening at the point of failure. It is often estimated as the average of yield and ultimate strengths.

# Annex F
(informative)

## Hydrogen Effects

Hydrogen can affect both the toughness as well as the crack growth rate of steel under cycle loading. Where hydrogen effects are suspected, lower bound toughness might be appropriate. Additionally, higher fatigue crack growth rates are observed for steel that is charged with hydrogen due to applied CP potential or corrosion related to sour service.

The potential for hydrogen effects can be factor if all of the following conditions exist:

— coating is suspected to have failed or to be in poor condition,

— water is present for a majority of the year,

— CP potentials are sufficiently high to produce adverse effects from atomic hydrogen, such as the formation of hydrogen blisters or cracking in hard microstructures,

— high hardness has been measured on the pipe,

— higher crack growth due to fatigue has been observed.

Where these factors are not present, hydrogen effects are not likely.

# Annex G
(informative)

# Fatigue $C$ and $m$ Values

A survey was performed of reported fatigue crack growth parameters determined from testing of line pipe materials. Results were also provided by a pipeline operator of samples of older vintage line pipe from three manufacturers. The results are summarized in Table G.1 and Figures G.1 and G.2 below.

**Table G.1—Survey Sampling of Line Pipe Fatigue Crack Growth Parameters**

| Source | Application | $C$ ksi (in.)$^{0.5}$ | $C$ Pa (m)$^{0.5}$ | $m$ |
|---|---|---|---|---|
| API 579-1 | Welds | 8.61E-10 | 1.65E-08 | 3.00 |
| Barsom and Rolfe | "Typical," ferrite-pearlite steels | 3.60E-10 | 6.89E-09 | 3.00 |
| Vosikovsky[50] | X65, in aqueous environments | 5.20E-10 | 9.59E-09 | 2.82 |
| Vosikovsky[51] | X65 in air, $\Delta K$ < 18 ksi (in.)$^{0.5}$ [20 MPa (m)$^{0.5}$] | 6.8E-11 | 1.3E-09 | 3.5 |
| | X65 in air, $\Delta K$ > 18 ksi (in.)$^{0.5}$ [20 MPa (m)$^{0.5}$] | 2.7E-09 | 5.2E-08 | 2.5 |
| | X65, sweet crude, $\Delta K$ < 31 ksi (in.)$^{0.5}$ [34 MPa (m)$^{0.5}$] | 1.4E-12 | 2.7E-11 | 4.8 |
| | X65, sweet crude, $\Delta K$ > 31 ksi (in.)$^{0.5}$ [34 MPa (m)$^{0.5}$] | 3.8E-08 | 7.3E-07 | 1.9 |
| | X65, sour crude, $\Delta K$ < 23 ksi (in.)$^{0.5}$ [25 MPa (m)$^{0.5}$] | 7.3E-14 | 1.4E-12 | 6.4 |
| | X65, sour crude, $\Delta K$ > 23 ksi (in.)$^{0.5}$ [25 MPa (m)$^{0.5}$] | 8.9E-9 | 1.7E-07 | 2.7 |
| Andreason and Vitovec | Grade B | 2.15E-13 | 4.12E-14 | 5.40 |
| Keller et al. (DOE) | X52 | 4.30E-11 | 8.24E-10 | 3.77 |
| San Marchi et al./ Stahlheim et al. | TMCP | 1.34E-13 | 2.56E-12 | 3.50 |
| Vintage line pipe, early 1950s | Youngstown DC-ERW | 1.12E-10 | 2.14E-09 | 3.31 |
| | Kaiser SSAW | 1.51E-11 | 2.89E-10 | 4.01 |
| | A.O. Smith EFW | 2.33E-11 | 4.46E-10 | 3.89 |
| Lambert et al. | X60, fatigue component of SCC lab testing with SCC crack growth rate of 0.0927 mm/yr (0.00365 in./yr) | 1.53e-14 | 2.92E-13 | 3.97 |
| Maxey | 10-in. and 12-in. OD X52 ERW (in air) | 2.12E-11 | 4.06E-10 | 4.00 |
| Maxey | 10-in. and 12-in. OD X52 ERW pipes (NaCl environment at free corrosion potential) | 8.33E-11 | 1.59E-09 | 3.60 |



The various rates listed above are compared in Figures G.1 and G.2, below. It is noted that the API 579-1 rate is an upper bound to the other reported values except at very high levels of applied $\Delta K$. Generally, values for $\Delta K$ will rarely exceed 50 ksi (in.)$^{0.5}$ ([55 MPa (in.)$^{0.5}$] in fatigue analyses. The data presented here are intended to indicate the potential range of values and not meant to imply that these values apply specifically to any particular pipe of pipe.

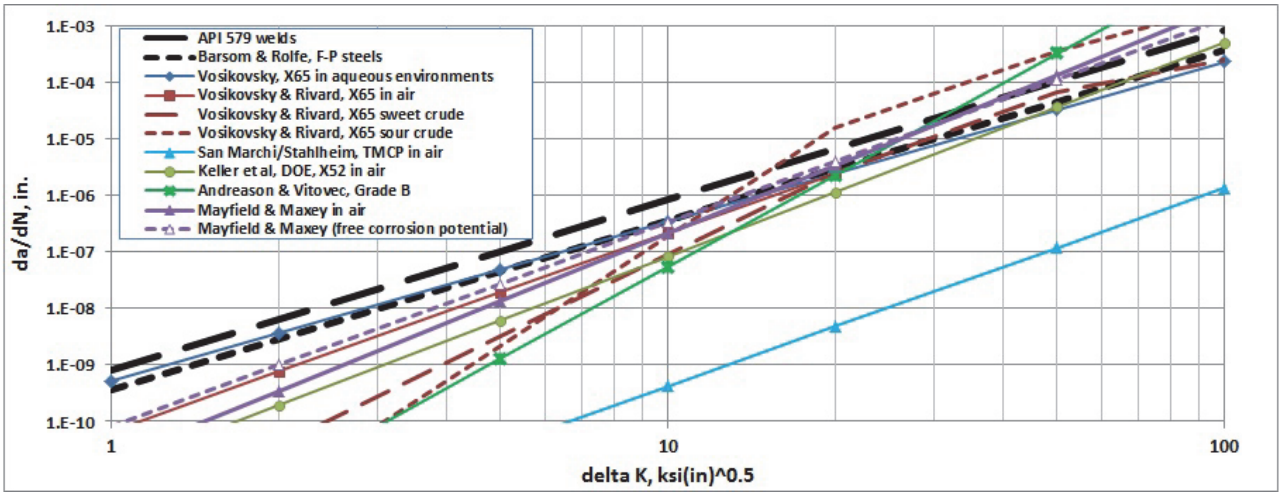



**Figure G.1—Fatigue Crack Growth Rate Parameters for Line Pipe, Various Sources**

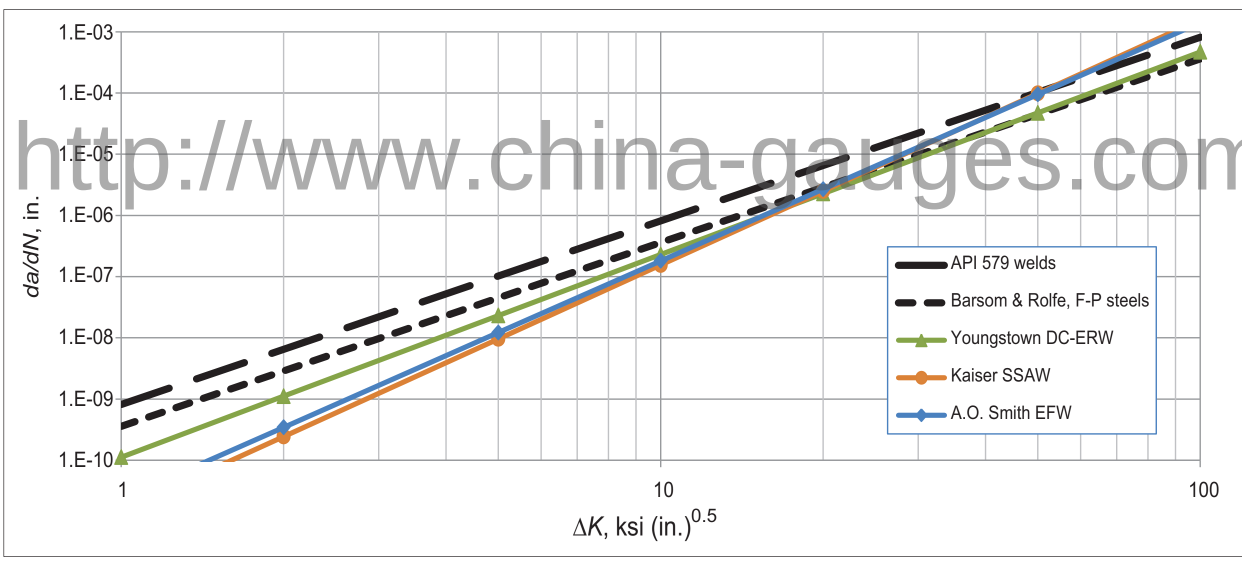





**Figure G.2—Fatigue Crack Growth Rate Parameters, Vintage Line Pipe Specimens**

# Annex H
(normative)

# Prediction of Crack Growth with Consideration of Variable Loading Conditions on Oil and Gas Pipelines in Near-neutral pH Environments

## H.1 Type of Pressure Fluctuations

Pipelines experience variable operating pressure fluctuations, which can be categorized as:

a) underload (Type I),

b) mean load (Type II),

c) overload (Type III) pressure fluctuations.

*Type I—Underload Pressure Fluctuations:* Figure H.1 shows typical underload pressure fluctuations for an oil and a gas pipeline. Type I is typically seen downstream of compressor or pump stations and is the harshest pressure fluctuation spectrum in terms of the crack growth rate. The maximum pressure of the Type I pressure fluctuation spectrum is often controlled to be at or close to the design limit, allowing fluctuations only to a level lower than the design limit. The spectrum consists of so-called underload cycles, which are large fluctuation cycles with low R-ratios (minimum pressure/maximum pressure), and minor pressure fluctuations with very high R-ratios, also known as ripple loads. Underload cycles in oil pipelines often have lower R-ratios, higher number of occurrences, and faster rate of pressure changes, as compared with underload cycles in gas pipelines. Ripple load cycles, also called minor cycles, are a main feature of gas pipelines.



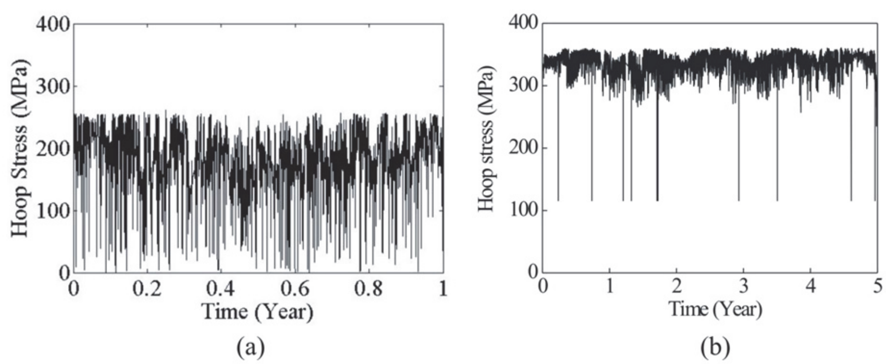



**Figure H.1—Type I—Underload Pressure Fluctuations for a) an Oil Pipeline and for b) a Gas Pipeline**

*Type II—Mean Load Pressure Fluctuations*: Figure H.2 shows Type II pressure fluctuations for an oil and a gas pipeline. Typically observed further down from compressor and pump stations, the average pressure in the Type II pressure fluctuation spectrum is lower than that in Type I, and pressure spikes with a pressure level above the average pressure/mean pressure but below the design limit are frequently seen. The mean pressure is still not low enough to eliminate the underload fluctuations typically seen in Type I.

*Type III—Overload Pressure Fluctuations*: Figure H.3 shows Type III pressure fluctuations for an oil and a gas pipeline. Type III typically exists at or close to a suction site, where pressure spikes above the mean pressure, also referred to as overload cycles, become predominant, while the occurrence of underload cycles is minimized.

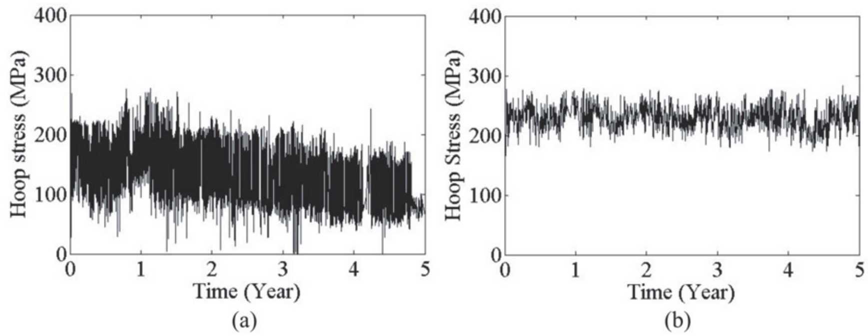



**Figure H.2—Type II—Mean Load Pressure Fluctuations for a) an Oil Pipeline and for b) a Gas Pipeline**

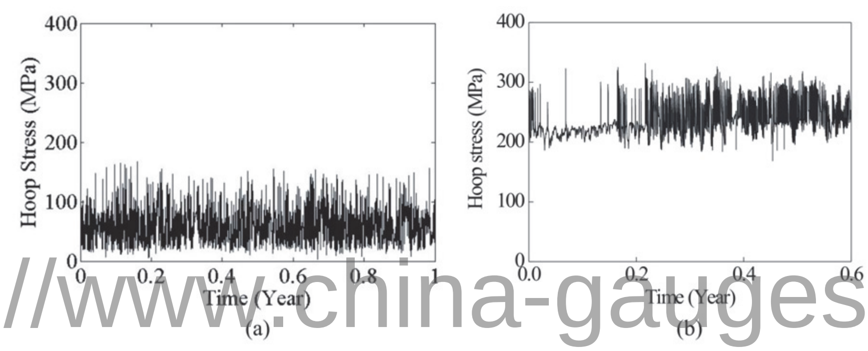





**Figure H.3—Type III—Overload Pressure Fluctuations for a) an Oil Pipeline and for b) a Gas Pipeline**

## H.2 Crack Growth Mechanisms

Figure H.4 is a three-stage bathtub model illustrating the various steps of crack growth in near-neutral pH environments. This is a revision of Parkins' 1987 bathtub model and is based on the latest understanding of crack initiation and growth of pipeline steels in near-neutral pH environments.

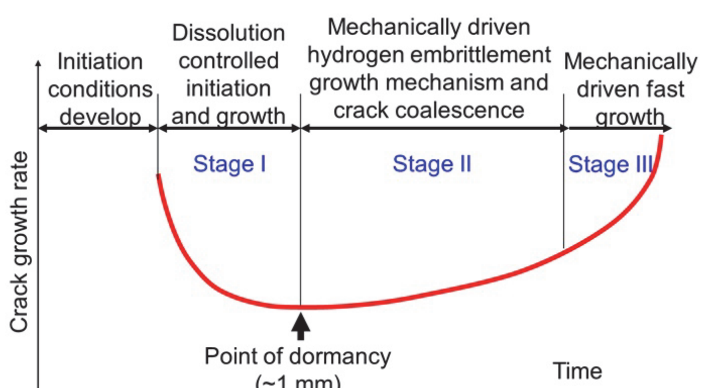



**Figure H.4—Revised Three-stage Bathtub for Crack Growth in Near-neutral pH Environments**

*Stage I—Dissolution Controlled Crack Initiation and Growth*: During this stage, the conditions for corrosion have been developed, such as coating damage, ground water in contact with the pipe surface, and lack of CP. Crack initiation results from localized corrosion at the pipe surface, resulting in crack-like defects. This stage is usually dependent on coating conditions, soil environments, and steel metallurgy. Mechanical driving forces such as operating pressure fluctuations are less important. The rate of dissolution reduces as crack depth increases and many cracks stop growing when reaching a crack depth of approximately 1 mm (0.039 in.), at which point the crack enters a state of dormancy. Stage I can be controlled through effective coatings and effective CP.

*Stage II—Mechanically Driven Crack Growth in the Presence of Hydrogen Embrittlement*: During this stage, the loading conditions, including loading history and loading frequencies, play a significant role in crack growth. The main loading considerations include the following.

a) Stress-dependent Loading Interactions—Previous cyclic loading with an R-ratio different from the current loading cycles can condition the crack tip mechanically to result in either an increase or decrease in the crack growth rate during current cycles and/or future cycles.

b) Loading Frequency—The variable rate of pressure fluctuations affect time-dependent contributions to crack growth, including the rate of corrosion, the rate of hydrogen diffusion and segregation to the crack tip, and the degree of crack tip blunting caused by low temperature creep and hydrogen facilitated local plasticity.

c) Stress-dependent loading interactions and loading frequency can also interactively affect crack growth; e.g. crack tip blunting as a result of low temperature creep would affect the stress state at the crack tip and thereby yield different stress-dependent loading interactions.

The above loading considerations are inherent of the mechanism of SCC of pipeline steels but are not considered in any existing crack growth models including the coupled SCC and fatigue analysis.



*Stage III—Mechanically Driven Fast Crack Growth*: During this stage, the mechanical driving force results in rapid crack growth of a sizable crack and failure is imminent. Integrity management measures should be taken prior to reaching this stage.

## H.3 Effect of Loading Interactions on Crack Growth Rate

It is well established in fracture mechanics that one underload cycle, as illustrated in Figure H.5, can cause mechanical damage to the crack tip such that subsequent minor cycles can either become propagating, despite being below the threshold for crack growth according to the Paris Law, or can propagate at a higher rate than the Paris Law would predict. On the other hand, one overload cycle, also shown in Figure H.5, can reduce the crack growth rate of subsequent cycles.

A simple comparison of crack growth rates under different loading scenarios (labeled as I, II, and III) is shown in Figure H.6. In this comparison, the underload cycles in all three cases have an R-ratio of 0.5 and the minor cycles in Scenario I have a ratio of 0.9. These minor cycles were determined to be nonpropagating based on the Paris Law but obviously lead to crack propagation when compared with the loading conditions of Scenario II, where crack growth was measured under constant amplitude loading conditions. In contrast, the crack growth rate was reduced when the minor cycles were replaced with a hold at the maximum load (Scenario III). This reflects the fact that crack growth proceeds by corrosion fatigue and the crack growth under constant load, a situation of SCC, can be negligible.

The loading frequency in Figure H.6 was kept the same in all three loading scenarios, reflecting the difference in crack growth rate caused by different stress-dependent loading interactions as defined previously. Figure H.7 shows the crack growth behavior over a wide range of loading frequency, reflecting the time-dependent loading interactions as

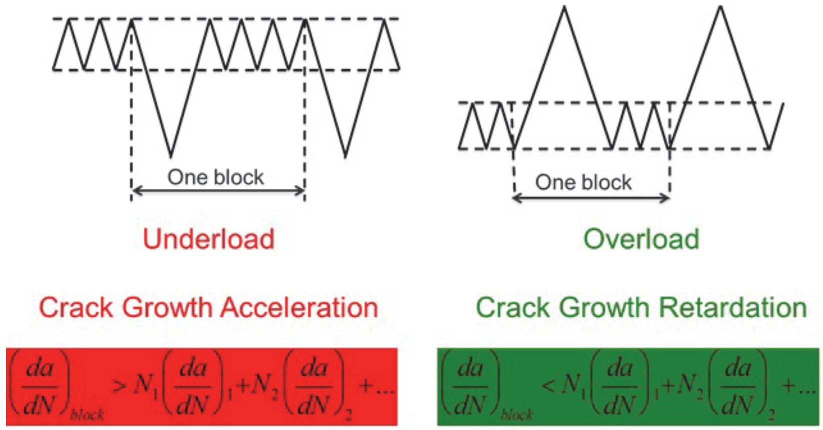



**Figure H.5—Effect of Loading Interactions on Crack Growth Rate**

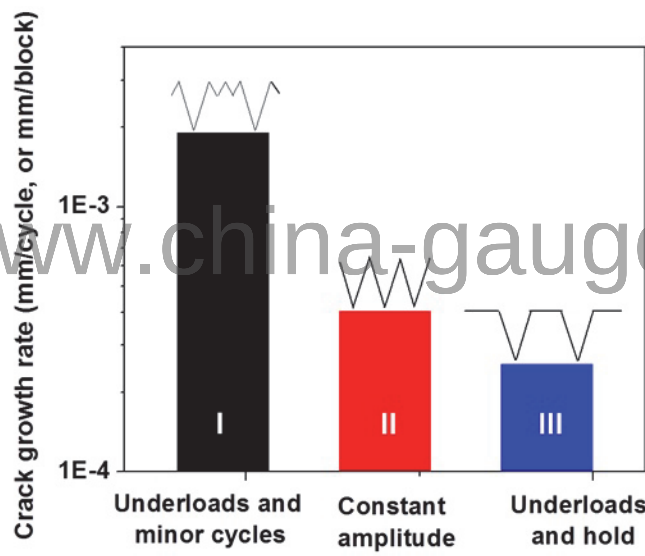





**Figure H.6—Comparison of Crack Growth Rates of the Same Pipeline Steel Tested Under Different Loading Scenarios**

described previously. As shown in Figure H.7, the dependence of crack growth on loading frequency can be divided into the following two frequency regimes:

a) HF regime, typically with a loading frequency higher than $10^{-3}$ Hz, where the crack growth rate increases as loading frequency decreases;

b) LF regime where the loading frequency is lower than $10^{-3}$ Hz and the crack growth rate is insensitive to the loading frequency under variable amplitude loading conditions, and a slight decrease of crack growth rate is observed under constant amplitude loading conditions.

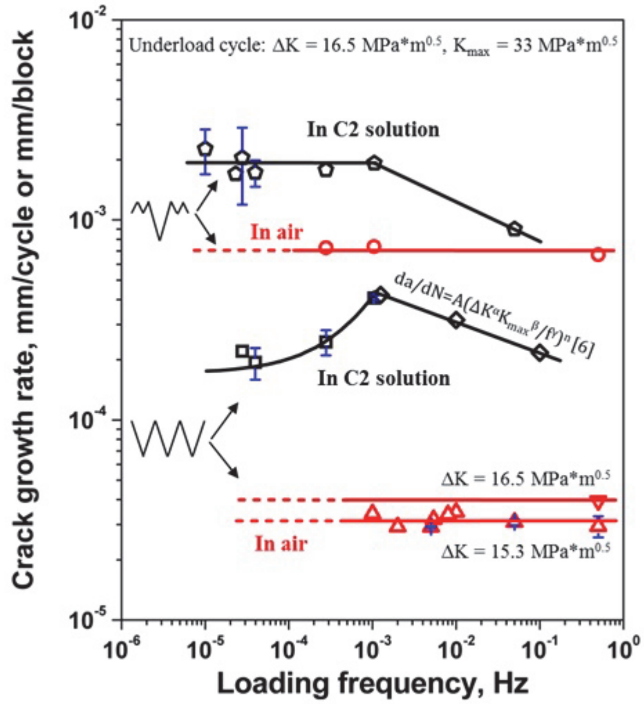



**Figure H.7—Effect of Loading Frequency on Crack Growth Rate Under Both Constant Amplitude Loading and Variable Amplitude Loading with Underloads and Minor Cycles**



The crack growth rate under constant amplitude loading can be described by the following equation:

$$\frac{da}{dN} = a\left(\frac{\Delta K^{\alpha} K_{max}^{\beta}}{f^{\gamma}}\right) + b \quad \text{(H.1)}$$

where

$a$, $n$ (= 2), $\alpha$ (= 0.67), $\beta$ (= 0.33), and $\gamma$ (= 0.033) are all constants;

$\alpha + \beta = 1$;

$b$ is the contribution of SCC, which was found to be about one order of magnitude lower than the first term in Stage II crack growth and can be ignored.

The overall power of the frequency, $f$, was found to be approximately –0.1, which is a factor representing the influence of the corrosion environment on the crack growth rate. The effect of corrosion is primarily achieved through hydrogen embrittlement, where hydrogen is generated in corrosion reactions. The transition of crack growth behavior from the HF regime to the LF regime is believed to be related to the saturation of hydrogen ahead of the crack tip at the peak stress of the loading cycle.

It has been experimentally determined that the crack growth threshold is significantly lower when loaded under variable amplitude loading. The critical R-ratio of minor cycles above which minor cycles will not contribute directly to crack growth is as high as 0.98.

Considering the contribution of minor cycles as well as loading interactions to crack growth, models that extract constant amplitude loading conditions from actual data of pressure fluctuations could significantly underestimate crack propagation in both oil and gas pipelines as these models do not consider crack growth acceleration caused by loading interactions.

# Annex I
(informative)

# UT and Magnetic ILI Technology

## I.1 General

Crack-detection ILI tools are evolving to meet the inspection challenges needed to ensure safe pipeline operation. There are two tool categories available for transmission pipelines: ultrasonic and magnetic. Ultrasonic tools detect all discontinuities, even the tightest cracks. Magnetic methods work best for volumetric anomalies, and a crack width or opening is an important parameter in detection. Other inspection technologies including eddy current, remote field eddy current, and radiography can detect cracks; however, no commercial tools are available for inspecting transmission pipelines at practical pigging speeds, conditions, and operational constraints.

## I.2 Ultrasonic

### I.2.1 General

The two categories of ultrasonic tools are classified by the methodology that the HF sound waves are coupled into the pipeline. The earliest commercial tools needed a liquid medium between the sound generator and the pipe. For pipelines that deliver a gaseous product, an electromagnetic method that directly produces the HF sound in the pipe is utilized, which does not require a coupling medium.

### I.2.2 Liquid-coupled Angle Beam Ultrasonic Testing



Angle beam ultrasonic inspection methods with the energy generated by piezoelectric transducers are commonly used in many industries for detecting cracks in metals. Implementations for ILI became commercial in the mid-1990s. These systems require the pipeline to contain liquid media for coupling the ultrasound from the transducer into the pipe; this complicates the utilization of this technology for natural gas pipelines.

Cracks have the potential to be detected using ultrasonic methods. This includes many of the cracks described in this document including:

— stress corrosion cracks (SCC);

— fatigue cracks;

— ERW bond line anomalies including lack-of-fusion, cold welds, penetrators;

— hook cracks in the HAZ.

The depth of crack-like features historically has been provided in bins, such as <1 mm, 1 mm to 2 mm, 2 mm to 4 mm, or >4 mm. As analysis methods, some newer systems provide crack depth measurements as a percentage of wall thickness or as a discrete depth. Using amplitude for sizing cracks is historically limited; many other methods such crack tip diffraction have been developed to overcome these limitations. Many factors influence amplitude reflected from a crack including variation from perpendicular, length, and branching. Detecting and sizing axial length and radial depth involves examining images of sensor output from both sides of the weld. The sizing method can work well for isolated planar radial cracks with a proven relationship between signal amplitude and depth. However, the configuration of natural cracks can reduce sizing accuracy. For example, multiple cracks in close circumferential proximity such as SCC colony can shadow some crack and cause multiple signals altering the signal amplitude. For seam weld, misaligned skelp and the complex shapes of some hook cracks can make sizing less accurate because the angle and curvatures can cause mode conversions that redirect ultrasonic energy.

The UT systems are sensitive to upset and trim associated with the fabrication of the weld, as well as inclusions and laminations that are often benign anomalies. Some of the same steel plate issues such as laminations and impurity segregation that lead to hook cracks also complicate the detection and sizing analysis. Distinguishing the fabrication and material variation from potentially significant weld seam anomalies requires examination of signals from multiple pairs of sensors and detailed analysis. These analysis methods are not always successful, and fabrication anomalies are falsely called as cracks and some cracks are dismissed as fabrication anomalies.

Multiple inspection vendors provide a configuration where each piezoelectric transducer is individually angled in the circumferential direction. The goal is to produce 45° ultrasonic angle shear waves in the pipe as shown in Figure I.1 for detection of an OD crack and Figure I.2 for an ID crack. The angle of the transducers in the product, defined by Snell's Law, depends on the speed of sound in the product relative to steel. The speed of sound is dependent on density and elastic constants. The range of angles is only a few degrees, but precise calibration of the product sound properties is important for an accurate inspection. Many vendors ask for a sample of the product. Product changes need to be anticipated as a recalibration might require rebuilding the sensor array.

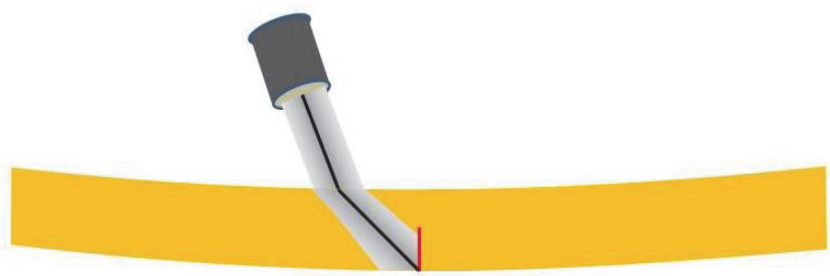




**Figure I.1—Outer Diameter Crack Detection Using a 45° Shear Wave (Referred to as Half Skip)**

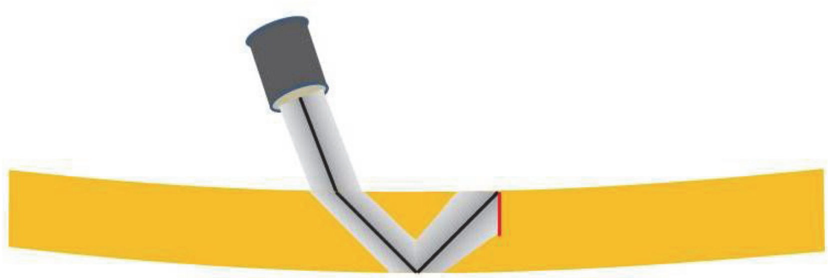
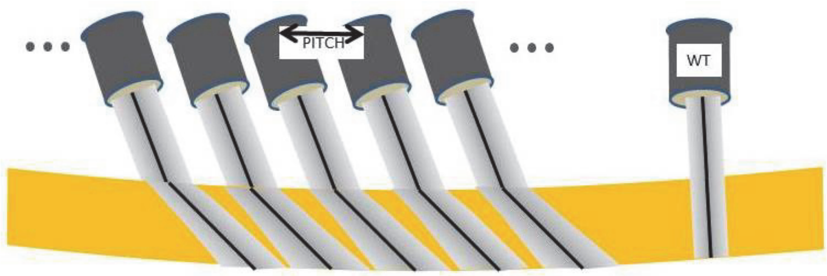


**Figure I.2—Inner Diameter Crack Detection Using a 45° Shear Wave (Referred to as Single or Full Skip)**

Sensors are spaced around the circumference to inspect the entire pipe as shown in Figure I.3. The sensor pitch around the circumference is fixed, typically on the order of 10 mm (0.4 in.). At discrete locations around the circumference are transducers aligned perpendicular to the pipe (called normal beam) to measure nominal wall thickness. The method can identify a crack's connection the ID or OD by measuring the wall thickness and signal arrival time.

The sensors are angled in both the CW and CCW direction as shown in Figure I.4. Therefore, the number of sensors is roughly the pipe internal circumference divided by the pitch times two (for CW and CCW configuration).

The 45° shear wave propagates back and forth through the pipe wall, skipping from the OD to the ID and back as shown in Figures I.5 and I.6. Under ideal conditions, four or more transducers will see a crack (e.g. for ID cracks: half skip, one and one-half skip CW and CCW).




A normal beam sensor (sensor marked WT) measure wall thickness at a few locations.

**Figure I.3—Sensors Spaced Around the Circumference to Achieve Full Coverage**

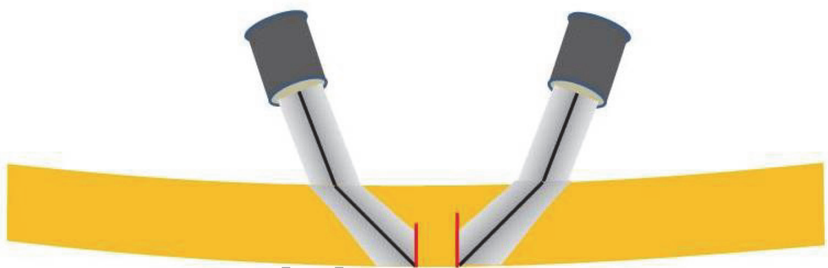




**Figure I.4—Sensors Are Angled in Both the Clockwise and Counterclockwise Direction**

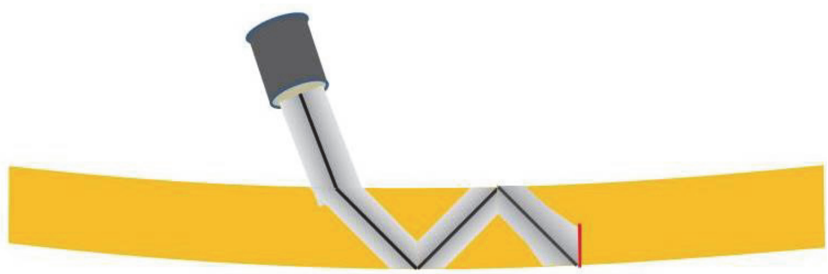


**Figure I.5—Outer Diameter Crack Detection Using a 45° Shear Wave (Referred to as One and One-half Skips)**

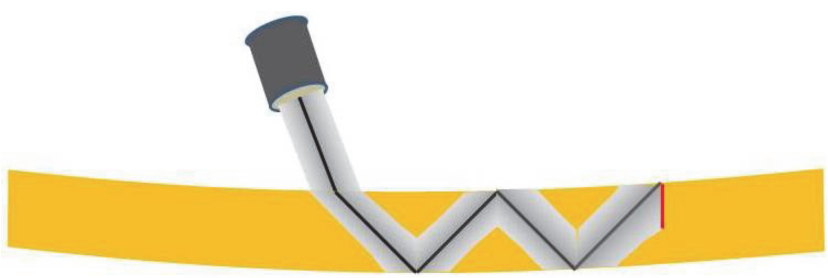


**Figure I.6—Inner Diameter Crack Detection Using a 45° Shear Wave (Referred to as Two Skips)**

For natural gas pipelines, the liquid-coupled technology is implemented by the process of filling part of the pipeline with liquid, a technique called batching. For many pipelines, the extent of the modifications that must be made to run liquid-coupled ILI tools can make a hydrostatic test an option that should be considered. For reliable crack detection, the crack orientation must be considered. For detection of axial cracks, the length must be nearly axial with angles up to 10° to 20° depending on tool type, and the crack depth should be radial with angles up to 45°. Crack sizing is also affected by angle. While the angle is dependent on many factors, for many cracks, the degradation in sizing accuracy begins at a degree or two. Branching and hooking also influence the sizing accuracy. As sizing technology is improving, vendors have begun to provide and will continue to refine crack profiles over the length of the crack.

These ILI tools have been reconfigured to detect circumferential cracking, with the sensors angled in the axial direction. Detection of girth weld anomalies and stress cracking due to bending has been detected. Again, for reliable crack detection, the crack orientation must be nearly axial within a few degrees.

### I.2.3 Phased Array ILI

Phased array is a different implementation of the liquid-coupled angle beam technique. Building on medical imaging technology, each sensor head contains hundreds of smaller piezoelectric elements. Using electronic timing, the beam can be steered to the proper angle. As shown in Figure I.7, the array elements can be fired to generate CW and CCW as well as listen for half skip through multiple skip return signals. Normal beam waves for wall thickness, midwall anomalies, and others can be generated by firing all the elements simultaneously illustrated in the right side of Figure I.7.



**Figure I.7—Phased Array Generation of 45° Ultrasonic Shear Waves in the Clockwise and Counterclockwise Direction as Well as Normal Beam for Wall Thickness**

As with the single piezoelectric transducer method, precise calibration of the product sound properties is important for an accurate inspection. However, product changes would only require changing the electronic timing used to set the beam. Another advantage is that circumferential resolution can be adjusted to as low as 3 mm (0.12 in.), although tool travel speed is limited with that tight of a resolution due to the data load.

### I.2.4 Electromagnetic Acoustic Transducers

EMAT based ILI is an ultrasonic method that does not require the liquid coupling needed for angle beam UT inspection. This evolving technology was first prototyped for pipelines in the 1980s, and functional commercial systems became available for pipeline inspection in 2000. Ultrasonic waves are generated directly in the pipe by an electromagnetic pulse from a coil in the presence of a strong magnet as illustrated in Figure I.8. These sensors can be configured to propagate in almost any direction including around the circumference of the pipe. While the method does not need a liquid for coupling the ultrasonic energy into the pipe, this method will work in a liquid pipeline. Unlike MFL where there are a few basic magnet configurations, a variety of EMAT configurations are possible. This technology is evolving with significant improvements and many configurations possible.

Compared to the angle beam ultrasonic systems, circumferentially guided ultrasonic waves that are generated by EMATs have significant differences, which lead to advantages and disadvantages. Unlike MFL, but like UT systems, EMAT methods are not significantly influenced by the crack opening. A primary difference is that the frequency of the EMAT-generated ultrasonic waves is an order of magnitude lower than liquid-coupled UT. Since frequency times the wavelength is equal to the sound propagation velocity, the lower frequency translates to a longer wavelength, which reduces the ability of resolve anomalies in close proximity. For example, an EMAT signal from an SCC colony

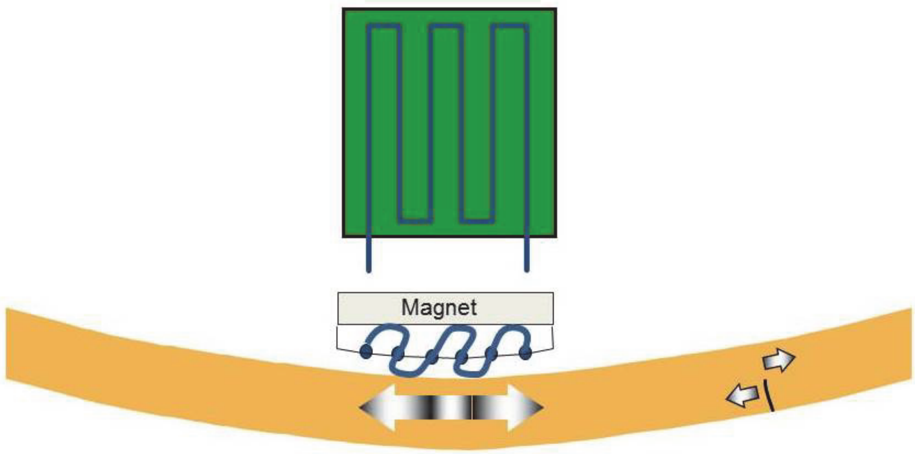



**Figure I.8—Electromagnetic Acoustic Transducer Ultrasonic Waves Generated Directly in the Pipe by Electromagnetic Pulse from a Coil in the Presence of a Strong Magnet**

typically appears a one larger signal; the individual cracks cannot be seen or sized. The EMAT-generated sound waves can detect upset and trim associated with the fabrication of the weld, but often propagate right past inclusions and laminations in the base metal. EMATs can be sensitive to the exterior coating adherence. Depending on the EMAT implementation, this can be a problem (cracks can be hard to detect in some coating types) or an attribute with coating information listed in the inspection results (such as discrimination between coating types and detection of coating disbondment).



EMAT systems have fewer larger sensors than angle beam ultrasonic systems; each sensor interrogates a larger volume of material than UT systems and combines the anomaly response over the aperture of the transducer. Since the EMAT sensors are up to an order of magnitude larger than UT sensors, these systems will have limits on detection of smaller anomalies and determining if anomalies are continuous or stitched. EMAT tools also can operate in both pulse echo and thru-transmission mode. The depth sizing is based on the signal from both sensor configurations where the angle beam method often uses multiple sensors to assess an anomaly. The longer wavelength and size of EMAT transducers currently challenges implementations for pipe smaller than about DN 300 (12 in. in diameter). It should also be noted that EMAT systems can be configured in many more ways than MFL or UT tools. This is due to the fact that there are many sensor configurations and the frequency of operation can be varied to control the wave type and mode of propagation. Hence, EMAT inspection tools from different ILI vendors can have more unique performance attributes and constraints than MFL or UT systems from different ILI vendors.

## I.3 Magnetic

MFL systems, regardless of configuration, can be designed to remain functional in an abusive pipeline environment for long distances at product flow speeds. The source of inspection energy (permanent magnets) requires no energy during an inspection and the sensors and data recorders require reasonably low power to operate. The magnetic flux naturally enters the pipe and distributes evenly to produce a full volumetric inspection. While the deficiencies of MFL systems are often highlighted, these attributes keep MFL at the forefront of pipeline inspection technologies.

Flux leakage methods systems have the potential to detect cracks, as evidenced by MPI that is a magnetic method that has been used for over a century. However, the detection of crack is best when the sensor is on the same side of the pipe as the crack that has broken the surface, since the flux leakage is the strongest. The width of the crack opening plays an important role in detecting these anomalies. Also, to be effective in detecting axially aligned features, the magnetization direction must be such that the magnetic field crosses the seam weld. The earliest approach is circumferential MFL, which is transverse to the more typical axial field used in the earlier MFL systems. The ILI tools have magnets in pairs, usually one pair 180° apart for small pipes and two pairs 90° apart for larger pipe. Arrays of the sensors between the poles around the pipe circumference are used to record defect signals. To ensure the full pipe circumference is inspected, a second magnetizer/sensor system follows the first, with sensors of the second module aligned with the magnetizer of the first module.

The number of sensors for a CMFL system is typically double the number used on a high-resolution MFL ILI tool for corrosion; the spacing between sensors is 2 mm to 5 mm (0.050 in. to 0.20 in.). This is needed because cracks produce narrow signals. The flux leakage is a vector quantity with flux moving along the pipe (axially) exiting the pipe (radially) and moving around the anomaly (circumferentially); hence, three components could be recorded. For CMFL, only one component is typically measured, mainly due to the higher sensor density and the physical size of commercially available sensors; the three component (axis) configurations are available from some vendors in only axial tools used more commonly for corrosion assessment.

Other implementations of circumferentially oriented MFL use a single helically shaped magnetizer. Some implementations use multiple short magnets; each magnet pair is offset around the circumference. For example, for a DN 150 (6-in.) line and 25-mm (1-in.) offset would require 20 magnet pairs to form one helix. The magnetizer does not have brushes; hard contact magnetizers are lower drag, but the ID roughness of the pipe and the root pass of the girth weld can cause reduced detection. Another implementation uses the same pole spacing as the common two module CMFL tool, with magnets indexed around the circumference in the form of a helix. This also uses brushes and overall length and is shorter for the same diameter pipe. The magnetization direction is not completely circumferential; the output is a combination of the axial and circumferential response. The performance specification of these helical implementations is comparable to CMFL systems; data that directly compare are not available.

## I.4 ILI Tools for Circumferential Cracking

### I.4.1 General



While a majority of cracks in pipelines are axial, either in the pipe body or seam weld, other crack orientations are possible. Circumferential cracks are possible in girth weld or in the pipe body when the pipe is under axial or bending loads. Both ultrasonic and magnetic tools are commercially available to detect circumferentially oriented crack-like anomalies.

### I.4.2 Reconfigured Liquid-coupled Angle Beam Ultrasonic

ILI tools with liquid-coupled angle beam ultrasonic inspection can be reconfigured for detection of circumferential cracks. The individual sensors in the sensor carrier would be angled to produce 45° ultrasonic angle shear waves with respect to the pipe axis. Since only the orientation is changed, the detection threshold and sizing capability is nominally similar to the more commonly used axial crack assessment systems. One exception is tool speed; at speeds above the maximum specified by inspection provider, the distance between measurements can increase. If this distance is too large, on the order of 13 mm (0.5 in.), circumferential cracks can be overlooked.

### I.4.3 Magnetic Flux Leakage

Axial MFL tools, the common implementation used to detect and size corrosion, can be used to detect circumferential cracks. The width of the crack opening plays an important role in detecting these anomalies. Since the cracks produce a short flux leakage signal, some inspection vendors acquire data at shorter intervals along the pipe. For example, a typical axial distance between successive readings is 2.5 mm (0.1 in.) for MFL tools configured to assess corrosion. For circumferential crack detection, the tools can be configured to acquire data every 1.25 mm (0.05 in.). This would double the amount of data, and the tool speed would have to be more closely controlled since excessive speed can prevent sampling at these fine increments. Smaller cracks can be detected in the pipe body than in the girth weld. For girth welds, there are three sources of signals; the amount of weld material, sensor lift off caused by the root pass penetrating beyond the ID of the pipe, and a crack signal can influence results. To detect girth weld cracks, these complex signals must be carefully analyzed. While most inspection vendors have reported detecting girth weld cracks, the method is most reliable for finding cracks that have a visible opening with more than a few inches of circumferential extent.

## I.5 Other Tool Types

### I.5.1 Liquid Wheel Ultrasonic

In the 1980s, one ILI company introduced a tool that could be run in both liquid and gas lines by sending ultrasound waves and detecting the wave reflections via transducers in a liquid-filled couplant wheel. This technology also has many historical runs including an extensive SCC inspection program by CEPA companies in the late 1990s. The tool has successfully detected SCC, long-seam defects, and other linear defects. To date, only large-diameter (>NPS 24) tools have been built.

Compared to traditional ultrasonic crack detection, liquid wheel ultrasonic (LWUT) is a lower resolution tool. The tool cannot reliably resolve subcritical defects and has discrimination issues when trying to characterize SCC and injurious cracks versus other benign reflectors. These problems are due to complex data-interpretation challenges and technology constraints and signal-noise issues. Some CEPA companies have found the best detection results are achieved by comparing multiple inspection runs. By overlaying and comparing the ILI data with a previous LWUT run, only the features that have changed over time are considered active cracks. Features that have not changed significantly over time are considered to be either benign reflectors or dormant cracks that are not an integrity concern. This data-interpretation approach can be used for most ILI technologies, but has shown promise of being especially effective at overcoming discrimination issues in the liquid wheel UT tool where discriminating growing SCC versus benign features is more of a challenge.

### I.5.2 Traditional Eddy Current Technology

#### I.5.2.1 General



Eddy current methods are used in other industries to detect cracks. Application of eddy current technology for pipeline inspection is limited by permeability of the steel, which reduces depth of penetration of the inspection energy by over an order of magnitude as compared to nonferromagnetic materials, such as aluminum, used for aircraft components. Eddy current methods are used for steel heat exchanger tubing where wall thicknesses are thinner and inspection speeds slower as compared to pipelines. Despite potential limitations, because of the opportunities for gas pipelines, eddy current methods have been developed for pipelines, and the development of new methods is possible.

#### I.5.2.2 Remote Field Eddy Current

This method is used in the water pipeline industry for inspection of mains as well as the tubing inspection. The excitation frequency of the inspection energy is on the order of 10s of Hz. The inspection speed is often limited to fractional feet per second to a maximum of 1 or 2, depending on the smallest anomaly targeted for detection. The speed restriction limits practical applicability in energy transmission pipelines.

#### I.5.2.3 Array Eddy Current Systems

Inspection systems that use an array of eddy current coils on flexible printed circuit material are being developed for pipeline inspection. Processing algorithms correct for the local variation of the pipe permeability and separation between the sensor and pipe (liftoff). Array for ITD assessment of cracks is showing promise. It is not known if array systems could be practical for detecting cracks on the outer surface from the inner surface because of the limited depth of penetration of eddy currents.

#### I.5.2.4 Specialized Electromagnetic Technology

The need to detect cracks in natural gas pipeline, where liquid coupling is rarely an option, prompts the continual development of unique electromagnetic inspection technologies. One major ILI vendor built a self-excited eddy current technology tool based on a permanent magnet system similar to a typical MFL tool. The technology showed promise for detection of SCC in both natural gas and liquid pipelines and does not require a liquid couplant to perform the inspection. Theoretically, this technology is not as sensitive to pipeline product speed and can collect optimum data at higher speeds, thereby lessening the operational and economic impacts of an SCC inspection run. This method has not become a commercial product.

PRCI is funding the development of an electromagnetic impedance measurement ILI prototype. The crack tool uses an array of electromagnetic sensors to identify defects and surface cracks on the internal surface of a pipeline.

# Annex J
(informative)

# Capabilities of In-line Inspection Tools for Specific Types of Axial Cracks and Anomalies

## J.1 Stress Corrosion Cracking

### J.1.1 Ultrasonic Methods for SCC

Ultrasonic methods are the most common inspection technology to detect SCC in pipelines. Liquid-coupled angle beam ultrasonic methods were the first reliable crack detection technology. EMAT technology is an emerging technology applied most commonly in natural gas pipelines.

The sizing of SCC by these methods is an area that most ILI vendors are continuing to improve. Historically, the tolerance associated with depth and length sizing, when taken into consideration, often results in excessive conservatism in integrity assessment and fatigue analysis calculations. Verification methods, such as ITD method or destructive assessment of pipes with cracks removed from service, can be used to improve results.

Verification can be challenging since field NDE and ILI do not make the same measurement. For example, MPI that can determine the surface length often includes portions of the crack that are below the level detectable by ILI. For depth, grinding determines when the deepest part of the crack disappears, while ILI measures the average depth over the aperture of the transducer.



### J.1.2 Magnetic Flux Leakage Methods for SCC

Typically, MFL methods are not specified to find SCC, though practitioners of this technology have examples where SCC has been found. The amount of flux leakage depends on crack depth, width, and length. The flux leakage on the ID surface of the pipe is much weaker and diffused as compared to the flux at the broken surface. The material property changes and ID surface condition produce comparable noise signals, making detection difficult and often unreliable for some pipes. Signal processing has proven useful for enhancing CMFL signals from cracks to detect some SCC, but performance is not proven and depth sizing is not available.

## J.2 Fatigue Cracks in Dents

### J.2.1 Ultrasonic Methods for Cracks in Dents

For liquid-coupled angle beam ultrasonic tools, the dent changes the angle needed to generate the 45° shear wave, so any energy that enters the pipe and reflects from an anomaly, would not reliably return to the sending sensor for detection, identification, and sizing. Therefore, the presence of a dent results in reduced crack POD below the vendor-published value. For EMAT systems, dents cause separation between the magnets and/or sensors. Sensor separation causes both loss of signal and complex signals. For some EMAT systems, one sensor interrogates a large portion of the circumference away from the sensor head. For this EMAT configuration, if the sensor is in an undented part of the pipe, the ultrasonic wave would propagate through the dent to the crack, and the EMAT receiver would detect the crack as if the dent was not there.

### J.2.2 Magnetic Flux Leakage Methods for Cracks in Dents

For MFL systems, dents cause separation between the magnets and/or sensors. Magnetizer separation reduces energy that enters the pipe. Sensor separation causes both loss of signal and complex signals. Therefore, the presence of a dent results in reduced crack POD below the vendor published value. The crack must be sufficiently open to produce an MFL signal per the specification of the ILI vendor. If a crack-like signal is found, then a crack could be present. The use of this technology for assessment of dents can help in the prioritization of dent anomalies by focusing repairs first on anomalies with potential crack indications. As with other applications for MFL for cracks, the crack must have some width, and the long dimension must be orthogonal to the magnetizing field; e.g. axial cracks are detected by circumferential MFL. Circumferential cracks in dents can be detected by axial MFL; the same configuration for general circumferential cracks applies including triaxial sensors and more dense data recording.

As indirect method for detecting susceptibility of fatigue cracks in dents formed by mechanical equipment, an alternate implementation of flux leakage is becoming available to identify cold working associated gouging process. This method uses high and low magnetic field differences to determine whether a region has a higher potential for cracking due to reduced ductility from cold working. While not directly identifying cracking, this method can help identify dents with corrosion from dents with excavator damage.

## J.3 Edge Mismatch in Autogenous Welded Pipe

Edge mismatch occurs in autogenous welded pipes during the fabrication process when the plates are misaligned when forced together. The result is a notch anomaly on one surface and normal looking weld on the other. Mismatched edges are more commonly found on the ID of the pipe with the extra base metal on the OD scarfed away. OD mismatches are less common as they can be visually detected at the mill. This anomaly is detected by both ultrasonic and magnetic methods. For ultrasonic tools, the notch anomaly is a good reflector of ultrasonic energy. Flux leakage methods can detect this anomaly since it appears as a metal loss anomaly. Fatigue cracks can initiate and grow from the step anomaly.

## J.4 Hook Cracks

### J.4.1 Ultrasonic Methods for Hook Cracks



Hook cracks can be curved and are not always perpendicular to the pipe surface; the complex geometry is augmented by fatigue cracks that grow radially in the remaining ligament. For ultrasonic ILI, the return echo from a hook crack will be higher or lower depending on whether the ultrasonic energy imping on the concave or convex side of the crack. A fatigue crack can return a second ultrasonic echo, which could align with the hook crack echo or not. Therefore, while detectable, the nature of echoes from hook cracks can reduce the depth accuracy. For liquid-coupled ultrasonic systems, the crack sound energy is directed from both sides of the crack and sizing models use both datasets. Operators have less experience with EMAT sizing of hook cracks, and the effect of the curved and angled nature is not known.

### J.4.2 Magnetic Flux Leakage Methods for Hook Cracks

Circumferential MFL methods can be more applicable for hook cracks than other crack types since many of these surface breaking crack-like features have width. The amplitude of the flux leakage signal is a strong function of crack width along with length and depth. Some hook cracks are more open than others at formation; internal pressure can increase this opening. The flux leakage on the ID of the pipe from an ID hook crack is much stronger than the flux leakage from the same size hook crack on the OD surface. Therefore, detection of hook cracks depends on whether the crack is on the ID or OD and the crack width when the hook crack formed along with the pressure, depth, length, and the wall thickness. The sizing of the depth and length of hook cracks also depends on these same variables and has not been proven to be accurate.

## J.5 Selective Seam Weld Corrosion

While not a crack as defined in this RP, SSWC produces responses that are similar to cracks.

## J.6 Bondline Anomalies

### J.6.1 General

A bondline anomaly, sometimes called a lack-of-fusion, is a tight planar discontinuity with a thin layer of oxide. The width of these defects is negligible. Therefore, these anomalies are not reliably seen with flux leakage methods. Below are comments on specific types of bondline anomalies that can be detected by ultrasonic methods.

### J.6.2 Lack-of-Fusion (Cold Weld)

The longer nature of lack-of-fusion can be detected with angle beam ultrasonic and EMAT tools as long as the depth exceeds the published threshold, typically 0.39 in. or 0.79 in. (1 mm or 2 mm), and the length exceeds 1 in. to 2 in. (25 mm to 50 mm). Slower tool speeds and a shorter distance between data recording locations can improve detection of shorter lack-of-fusions. For example, common detection schemes to identify cracks after 5 to 10 successive signals are detected. Therefore, at 0.12 in. (3 mm) between successive points, the cracks have to be 0.59 in. to 1.19 in. (15 mm to 30 mm long) to be detected; at 0.079 in. (2 mm) between successive points, the cracks have to be 0.39 in. to 0.79 in. (10 mm to 20 mm) long to be detected.

### J.6.3 Penetrators

Penetrators typically have a length of less than a 6 mm (0.25 in.), which is below the length threshold for current angle beam ultrasonic tools. Under certain circumstances, groups of penetrators in a short distance can be detected by EMATS and, to a lesser extent, angle beam ultrasonic tools.

### J.6.4 Stitching



The longer nature of stitching can be detected with angle beam ultrasonic tools as long as the average depth of the intermittent pattern exceeds the published threshold, typically 0.39 in. or 0.79 in. (1 mm or 2 mm).

## J.7 Fatigue Enlargement of Cracks

### J.7.1 Ultrasonic Methods for Fatigue Enlargement

Fatigue cracks are detectable using ultrasonic methods. Cracks that have extended by fatigue will reflect more of the incident ultrasonic energy and therefore should be identified as growing in repeated ILI inspection. However, some cracks that are extended by fatigue (such as hook cracks) have complex geometries that can make detection of the extension and sizing difficult. Not all extensions of the crack will be detectable beyond the originally detected anomaly.

### J.7.2 Magnetic Flux Leakage Methods for Fatigue Enlargement

While flux leakage method has the ability to detect some seam anomalies that can grow due to fatigue, the tight nature of fatigue cracks makes detection crack growth improbable.

## J.8 Cracks in Hard Spots

The most common approach for assessment of cracking in hard spots is a two-step approach using ILI and in the ditch assessment. Since the 1990s, common axial MFL tools have been reconfigured to detect hard spots. Since hard spots have different magnetic properties than the surrounding pipeline steel, the reconfigured tools can detect hard spots by measuring changes in the residual magnetic field or the magnetic permeability. A more recent approach, some newer MFL tools have a second low field magnetizer to detect gouging in dents; this low field can also detect hard spots. The benefit of this approach is better characterization of dents with a hard spot assessment. Both liquid-coupled ultrasonic tools and EMATs can detect cracks in hard spots, but this approach is not commonly used.

When hard spots are detected with an MFL approach, ITD assessment for cracking would be used on a few selected anomalies. This includes magnetic particle testing (MT) and hardness testing. If cracks are not found in the selected hard spot anomalies, it can be assumed that the condition needed to produce cracks in hard spots is not present, and that the cracking threat is addressed.

## J.9 DSAW and SSAW Cracking

### J.9.1 General

Cracks can occur in submerged arc seam welds, either single (SSAW) or double (DSAW), including toe cracks at the weld, shrinkage cracks in the filler area, lack-of-penetration, and lack-of-fusion.

### J.9.2 Ultrasonic Methods for Assessing DSAW and SSAW Cracking

The cracks that form in submerged arc seam welds reflect ultrasonic energy. However, the deposited metal in the caps and roots on SSAW and DSAW also reflect ultrasonic energy that mix with potential crack signals. The separation of the seam weld indications from crack anomaly signals is a labor-intensive process that can decrease POD of seam cracks. EMATs also detect both the cracks and deposited metal; the long wave length nature of these tools cannot distinguish between the two reflections.

### J.9.3 MFL Methods for Assessing DSAW and SSAW Cracking

CMFL methods can be applicable for SSAW and DSAW anomalies since many of these features have width. The amplitude of the flux leakage signal is a strong function of crack width along with length and depth. Some lack-of-penetration cracks are more open than others at formation. The flux leakage on the ID of the pipe from an ID crack is much stronger than the flux leakage from the same size crack on the OD surface. Therefore, detection of SAW toe cracks and other anomalies depends on whether the crack is on the ID or OD and the crack width when the crack formed along with the pressure, depth, length, and the wall thickness. The sizing of the depth and length of cracks also depends on these same variables and has not been proven to be accurate.

# Annex K
(informative)

# In-the-Ditch Technology

## K.1 Magnetic Particle Inspection for Crack Detection

MPI is used to screen the pipe for cracks. This NDT method is used in many industries to detect surface and slightly subsurface discontinuities such as cracks in ferromagnetic materials, steel being the most common. In MPI, a magnetic field is induced in a test piece; the magnetic flux deflects and leaks out in the vicinity of a crack. Small magnetic particles, typically less than 20 microns (0.79 mil), are sprayed on the pipe. The magnetic particles cluster at the discontinuity to form an indication. The particles remain at the discontinuity after the field is removed until they are physically moved.

The MPI method is an efficient screening tool with the inspection of a standard pipe joint taking less than an hour; the documentation time is proportional to the number of anomalies detected. For daylight inspection, the most common approach for pipelines, a very thin white layer of paint is applied to the weld seam and black particles are used to detect flaws. A technician performing an MPI is shown in Figure K.1.

**Figure K.1—Example of a Magnetic Particle Inspection**

## K.2 Ultrasonic Crack Detection

### K.2.1 General

Many ultrasonic methods have been developed to detect and size cracks in metals. Initially, when cracks were detected, the amplitude was used to assess the size of the cracks. While many processes have been developed, measuring the amplitude of reflected signal is a relatively unreliable method of sizing defects because the amplitude strongly depends on the orientation of the crack. Currently, the pipeline industry most commonly uses two automated methods for the inspection of seam welds; time information is now used rather than amplitude to size cracks:

— TOFD,

— phased array ultrasonic.

### K.2.2 Time-of-Flight Diffraction

TOFD uses the time of flight of an ultrasonic pulse to determine the position of a reflector. In a TOFD system, a pair of ultrasonic probes sits on opposite sides of a weld. One of the probes, the transmitter, emits an ultrasonic pulse that is picked up by the probe on the other side, the receiver. Figure K.2 shows a typical inspection head and a pipe with calibration notches in the seam weld.

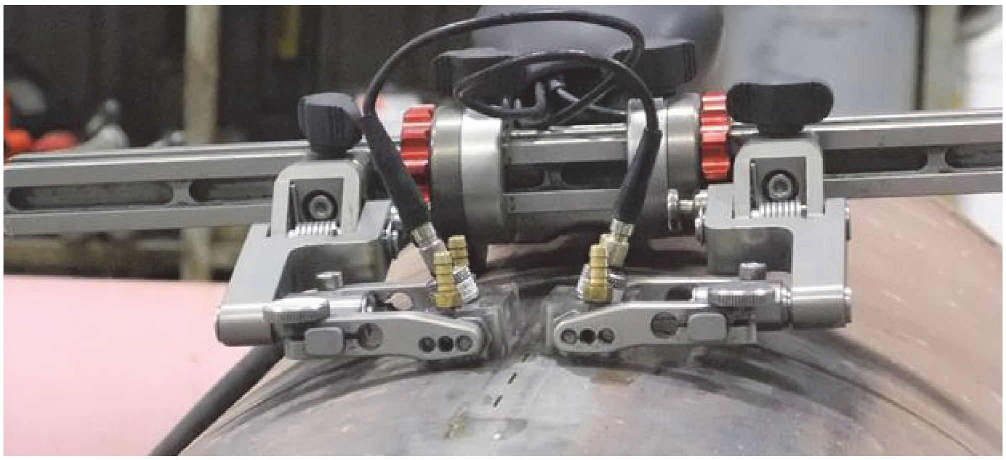


**Figure K.2—Time-of-Flight Diffraction Head for Seam Weld Inspection**



In a typical seam weld inspection, the signals picked up by the receiver probe are from two waves: one that travels along the surface and one that reflects off the far wall. For a good weld, the signals are consistent as the inspection head rolls along the pipe. Figure K.3 shows 2 m (6.5 ft) of pipe with a good seam weld with the surface wave illustrated in red and the bottom reflected wave in green. The small variations are the natural variation in seam welds. While TOFD limits the capability to detect small defects, the burst tests reported elsewhere show that many noncritical anomalies can be detected.

When a seam weld defect interrupts the sound path, the wave has different travel time. Furthermore, there is a diffraction of the ultrasonic wave from the tip(s) of the crack. Figure K.4 shows 2 m (6.5 ft) of pipe with anomalies that require additional analysis at approximately the half-meter point.

The inspection system displays the reflected and mode converted waves. Using the measured time of flight of the pulse, the depth of a crack tip can be calculated automatically by simple trigonometry. This method is more reliable than traditional amplitude based UT, as summarized by the study undertaken by the Electric Power Research Institute to assess the performance of commonly used ultrasonic techniques and procedures for pressure vessels. Techniques assessed in this study include TOFD, backward-scattering tip-diffraction, and conventional ultrasonic techniques. This study was performed before phased array ultrasonic methods were widely practiced. While the arrival time of the pulses can be used to provide reliable depth information, sizing assumes a vertical crack. The signal does not contain information on whether the crack is vertical, at an angle, curved, or other geometrical variation.

### K.2.3 Linear Phased Array Inspection Technique

#### K.2.3.1 General

A linear array probe contains a series of long, thin transducers closely spaced and parallel to one another. It resembles a conventional, monolithic transducer element that has been repeatedly sliced by a slitting saw. Each array element is connected to a separate pulsar, receiver, analog-to-digital converter, and delay generator. All the array elements are pulsed, and then their received waveforms are summed and the resultant A-scan is recorded. By adjusting the timing of the pulsing and reception of each element, the angle and focal point of the ultrasonic beam can be controlled. The beam

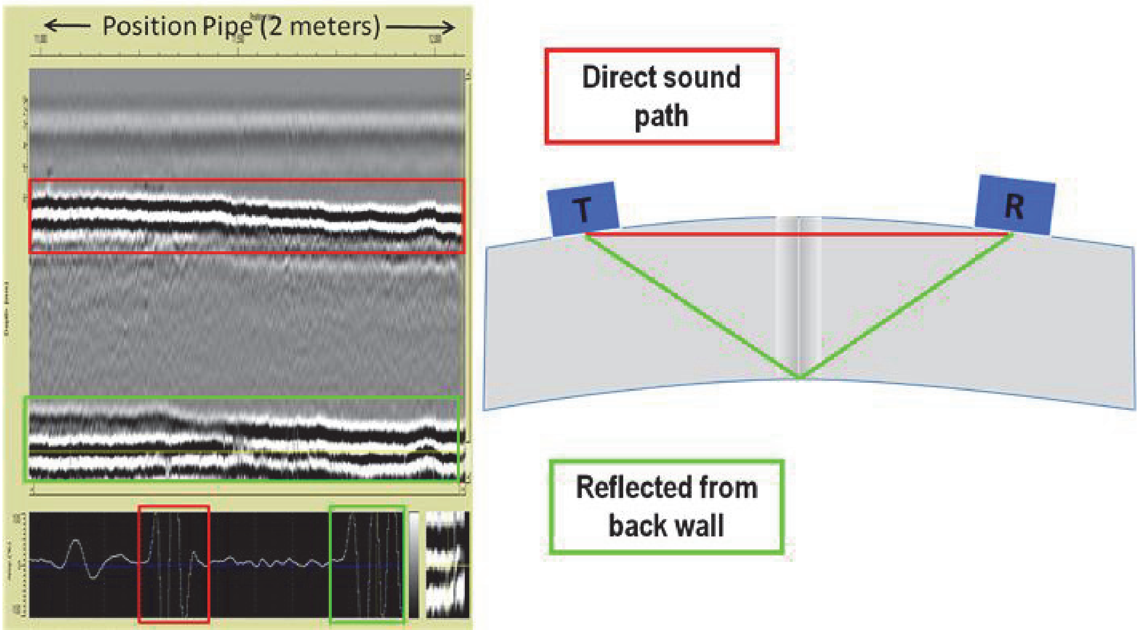



**Figure K.3—Typical Inspection Result for 2 m of Anomaly-free Seam Weld**



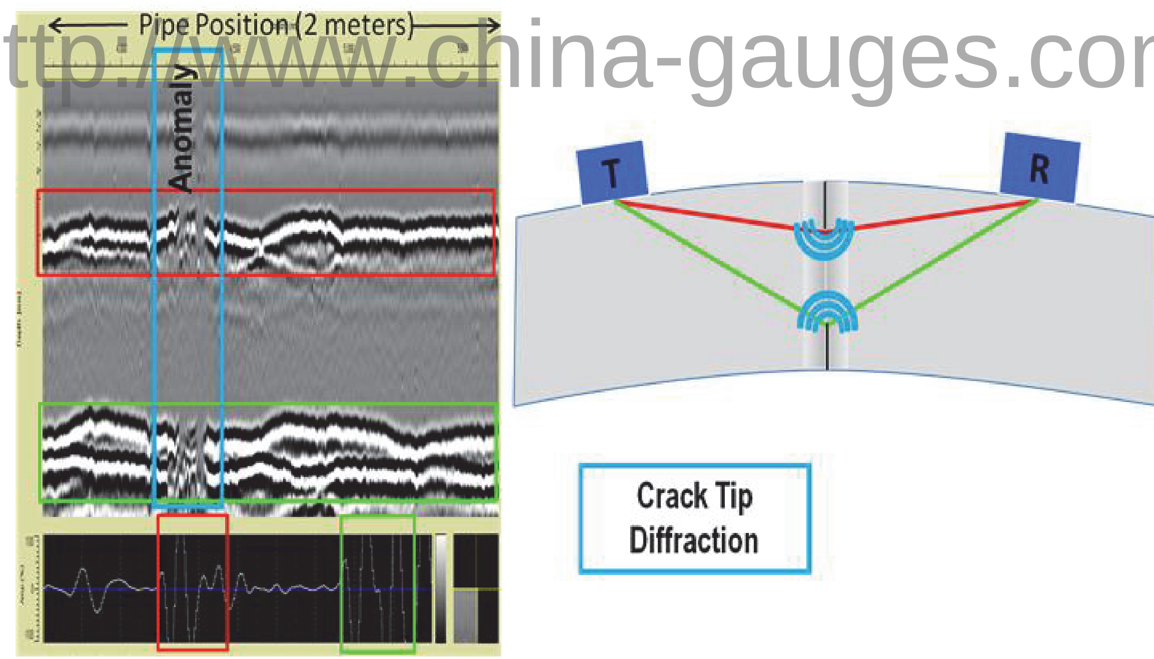



**Figure K.4—Typical Inspection for Two Anomalies—Requires Additional Analysis**

angle and focal depth can be changed from one pulse to the next by this electronic control process. In this manner, a single array probe can be used to produce beams at many different angles. When an array produces consecutive beams of slightly different angles, a fan-shaped image called a "sector scan" is formed as shown in Figure K.5. (The sector-scan image is familiar to most people from their experiences with fetal ultrasound imaging and the "pie-wedge"-shaped images of infants in utero.) As the operator moves the probe along the surface of the part being inspected, the instrument displays and updates in real time a wedge-shaped cross-sectional view of the interior of the component and any flaws that are present in it. The sizes of the flaws are represented directly in the image.

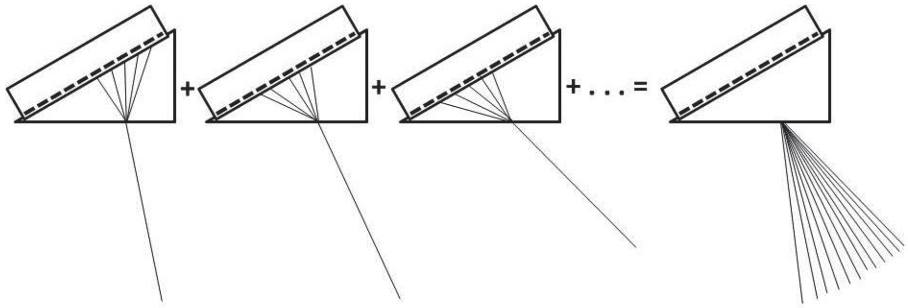



**Figure K.5—Principle of a Sector Scan**

For industrial applications, a linear array produces sound waves between 2 MHz and 10 MHz; the higher frequency selected for its high sizing resolution, and the lower frequency selected for better detection. The number of elements in the array in commercial equipment is typically a power of 2 and usually 32 or 64 elements. The shear wave mode is typically selected to allow the cracking to be imaged in the full-vee path after the sound beams had reflected from the pipe's inside surface (Figure K.6). Phased array systems can best programmed to perform sector scans over a range of beam angles to ensure the weld is assessed. A typical range is from 30° to 60°. The angel is swept in discrete angle increments, from 0.1° to 0.5° increments. Smaller angle increments allow more precise depth measurements, but scanning takes more time as a result. At 0.2° increments, a phase array system would have a precision of about 0.025 mm (0.001 in.) for a depth measurement. Each beam was focused at the three-fourths vee path position, which is at midwall after the reflection from the inside surface (Figure K.7).



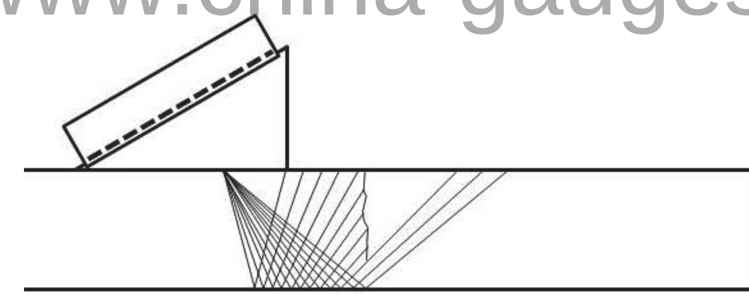


**Figure K.6—Imaging a Crack at the Full-vee Path Using a Sector Scan**

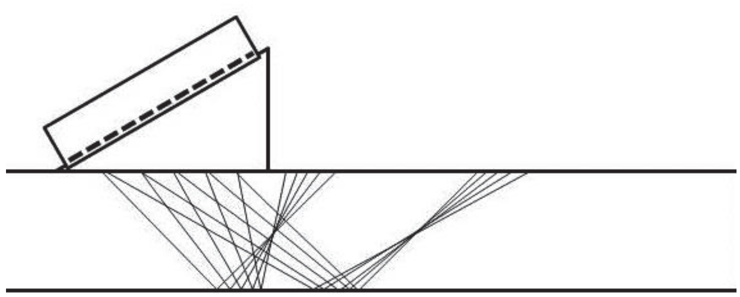


**Figure K.7—Focused Beam Can be Attained at the Three-fourths-vee Path—Entire Heat-affected Zone Is Assessed**

#### K.2.3.2 Manual Examination

In areas where MPI and TOFD methods detect cracks, the crack depths can be assessed with manual phased array imaging. In manual examination mode, the operator moves the probe over the pipe's outside surface and views the continually updated sector-scan image. When the image of the anomaly of interest is presented, the operator uses on-screen cursors to measure the crack depth. Specifically, the operator positions one cursor at the position of the crack tip response and the other cursor at the position of the low-amplitude responses that are received from the roughness of the outside surface of the pipe. The difference between the vertical positions of the two cursors is equal to the height of the crack. In this way, the depth measurement does not rely on a nominal value of the pipe thickness, but includes a measurement of the thickness at the crack location.

#### K.2.3.3 Automated Examination

To assess the entire seam weld and not just one axial location, automated measurements can be performed. A three-dimensional scan can be attained by attaching to a computer-controlled scanning device and data acquisition system. The probe was scanned in the pipe axial direction, every 6.3 mm (0.25 in.) acquiring a sector scan as described above. At the end of the scan line, the probe was incremented 3.1 mm (0.125 in.) in the circumferential direction, and the cycle was repeated. The ultrasonic coverage can be quite robust; every point within the material was hit by several different beam angles because the sector scans overlapped significantly, as shown in Figure K.8. Once the computer assembles the data into a volumetric image, images of specific planes can displayed as shown in Figure K.9; typical plains include all one depth (top image), along the pipe (lower left image) for the examination of seam welds, or around the circumference (lower right image).



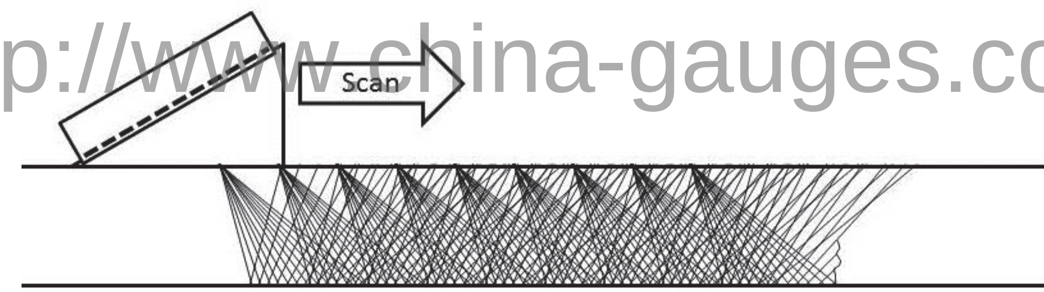



**Figure K.8—Dense Overlap of Sector Scans Circumferentially Indexed by 3 mm (0.12 in.)**

## K.3 Full Field Inversion

An emerging technology to imaging of defects in longitudinal weld seams is the full field inversion (FFI) method. FFI finds its origin in the application field of seismic exploration where acoustic wave fields are used to reconstruct structures and layers in the subsurface. With the introduction of ultrasonic array technology, the principles to reconstruct images from measured wave fields became applicable for other applications such as girth weld inspection. The most significant benefit over a standard TOFD and phased array methods is having a two-dimension cross sectional image as shown in Figure K.10.

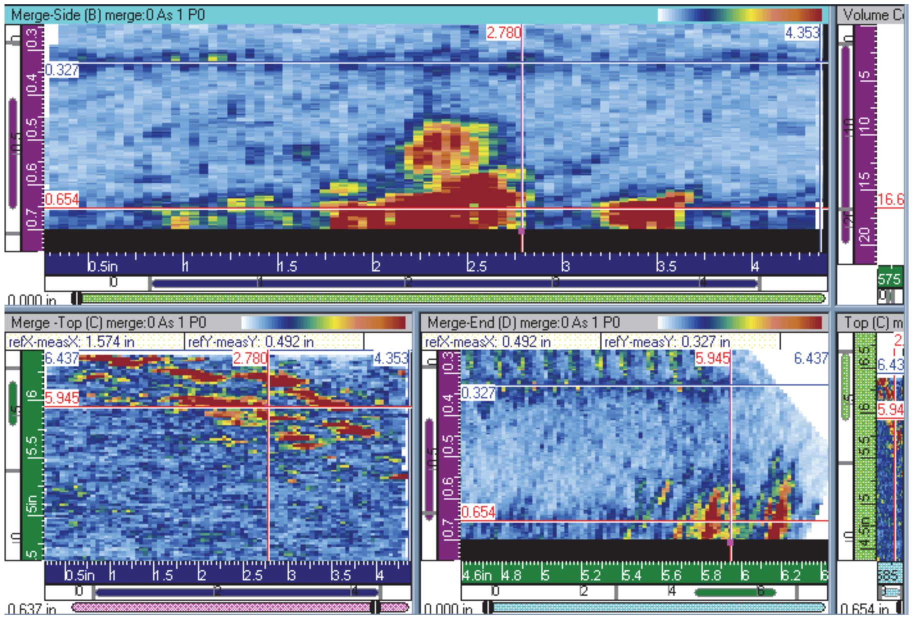



**Figure K.9—Example of Orthogonal Views**



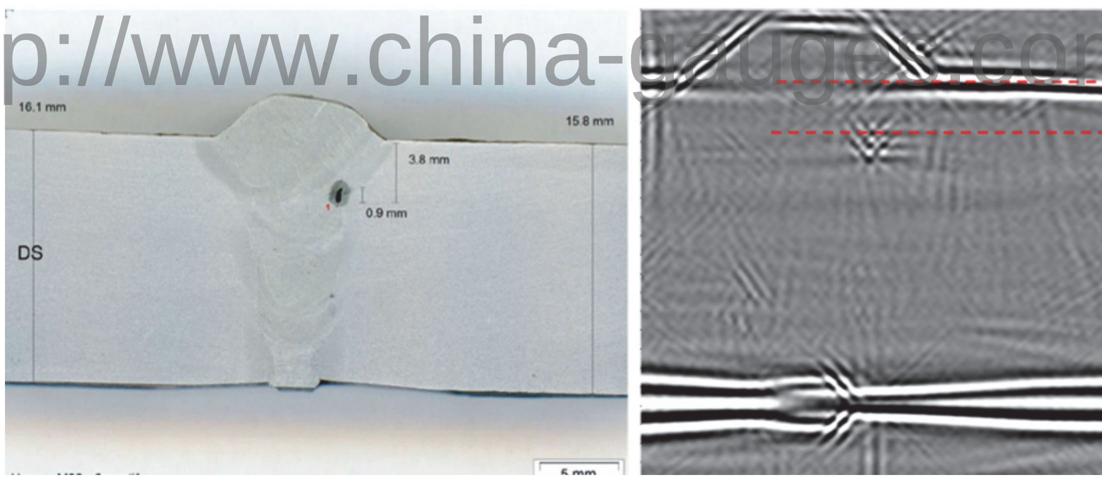



**Figure K.10—Example of Full Field Inversion of a Weld**

# Annex L
(informative)

# Example of an ILI Response Protocol

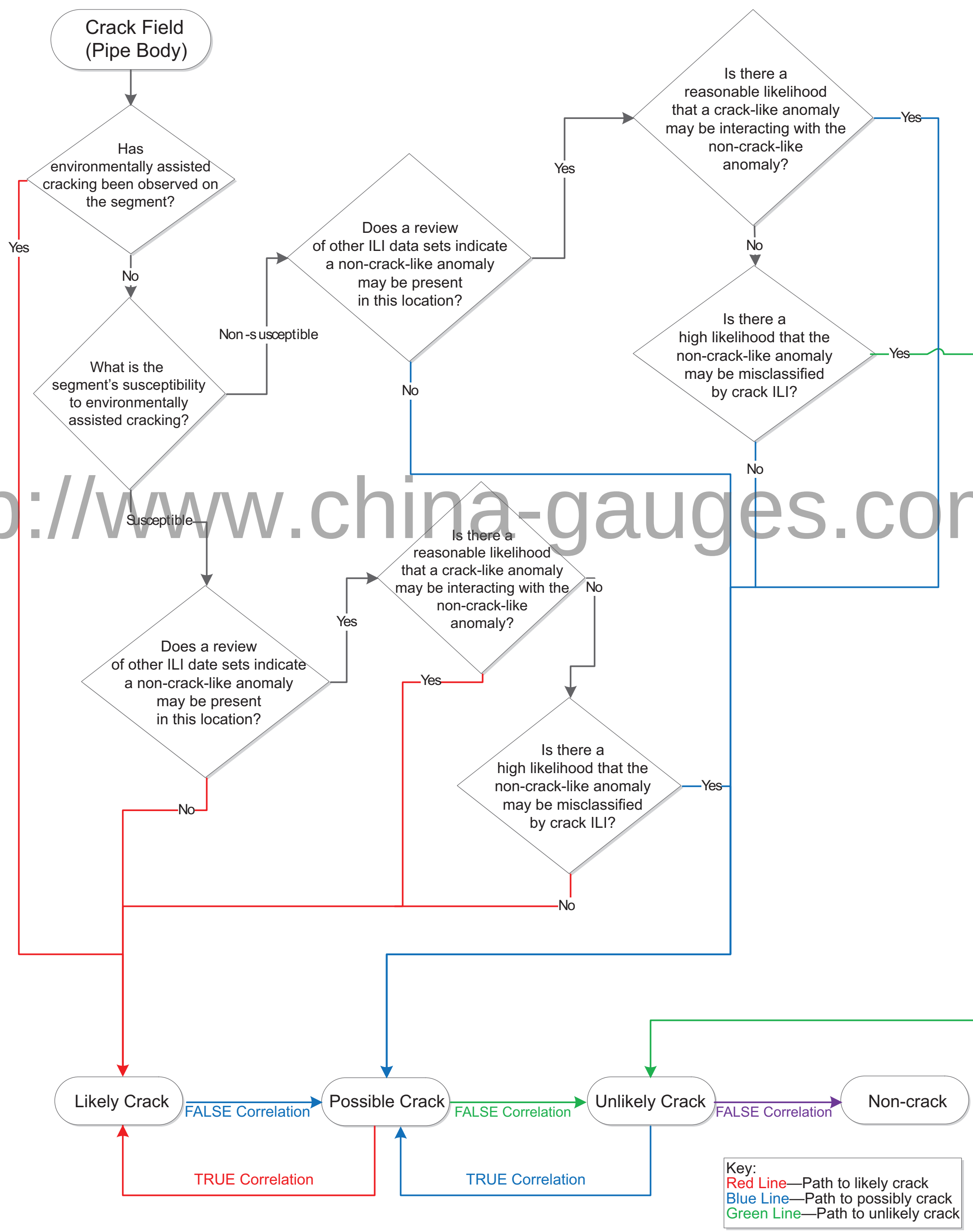




**Figure L.1—ILI Response Protocol—Example**

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