

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	<i>Code of Federal Regulations</i>
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 ₂ S	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



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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 disbanded 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 temperature 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.

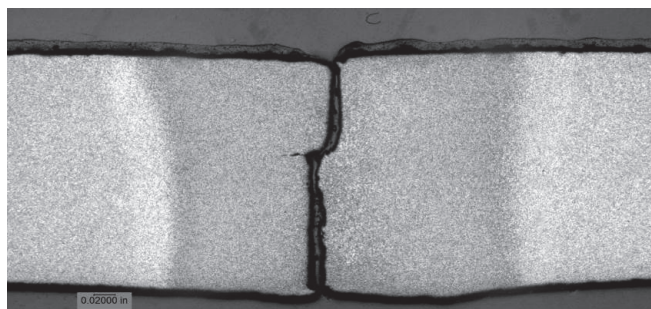
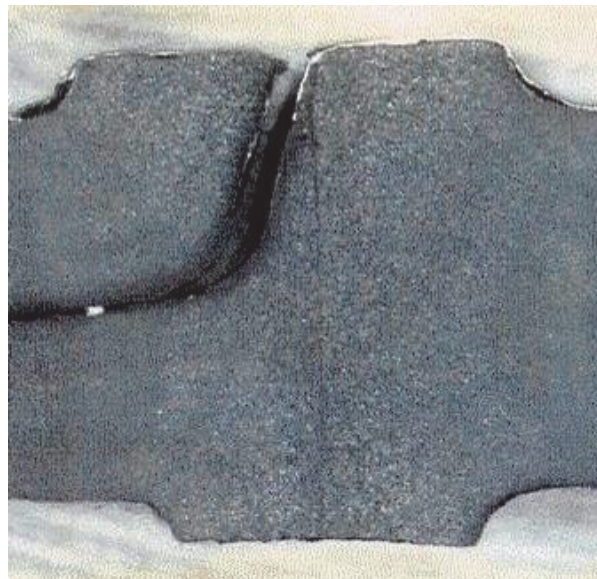


Figure 2—Hook Crack and Fatigue Crack Extension in Low-frequency Electric Resistance Welding Pipe



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 grow 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.

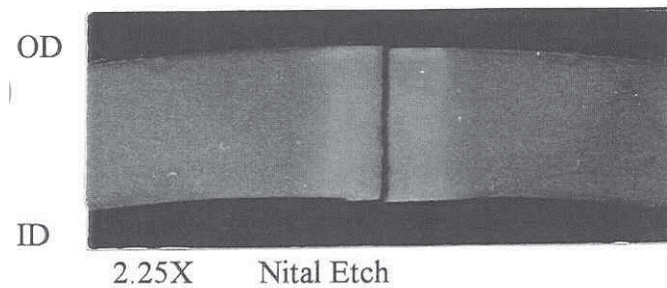


Figure 4—Lack-of-Fusion Defect

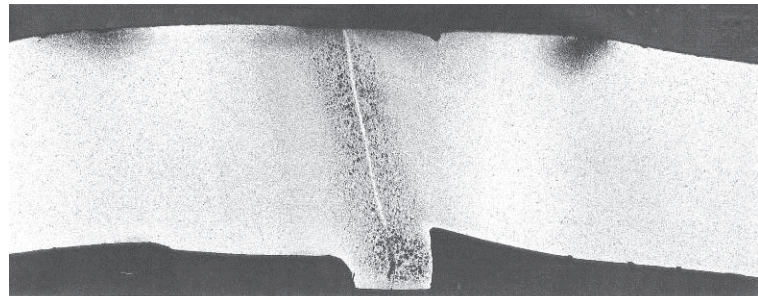


Figure 5—Direct Current Welded Seam with Offset Skelp Edges

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.

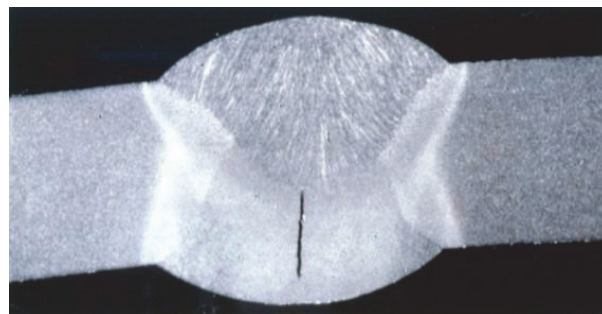


Figure 6—Weld Metal Crack (Hot Crack)

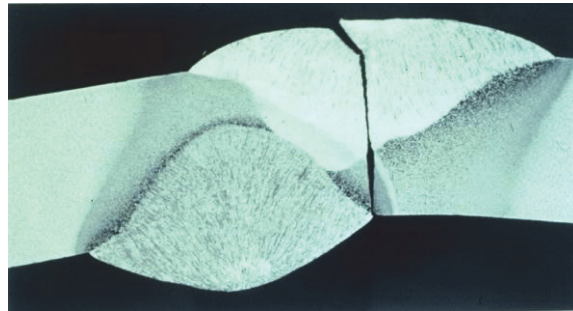


Figure 7—Toe Crack (Also Contains Offset)

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 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.

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

where

P_x Intermediate pressure point between pressure sources, psig;

P_1 upstream discharge pressure, psig;

P_2 downstream suction pressure, psig;

K SG $\times$ (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.

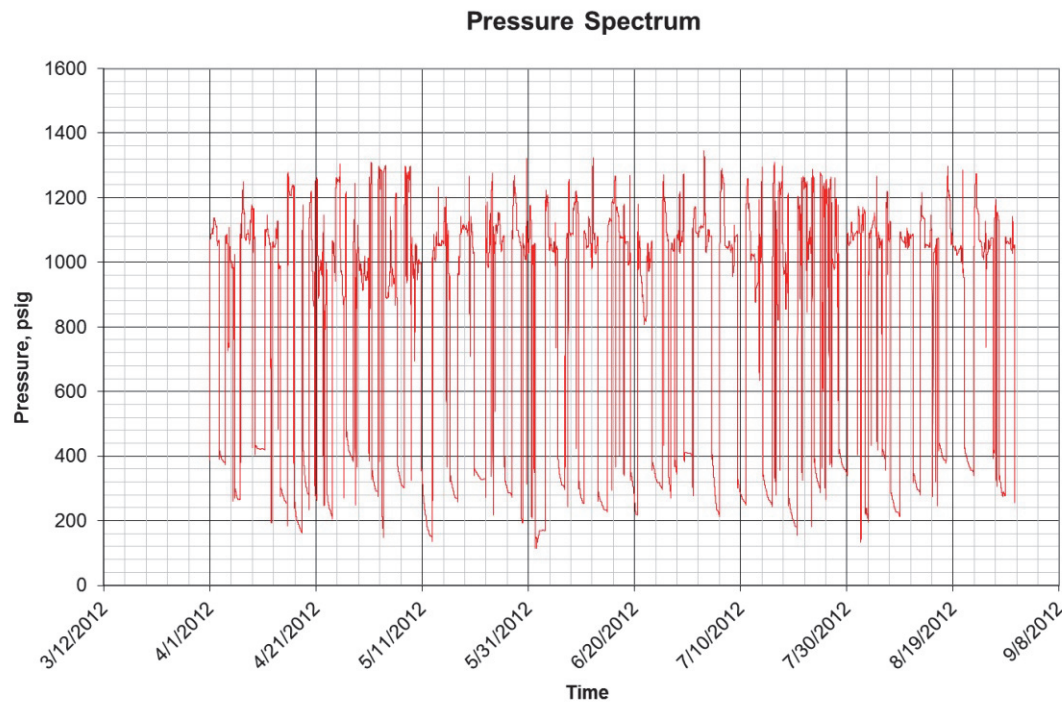


Figure 8—Example Pressure Spectrum from a Liquid Pipeline

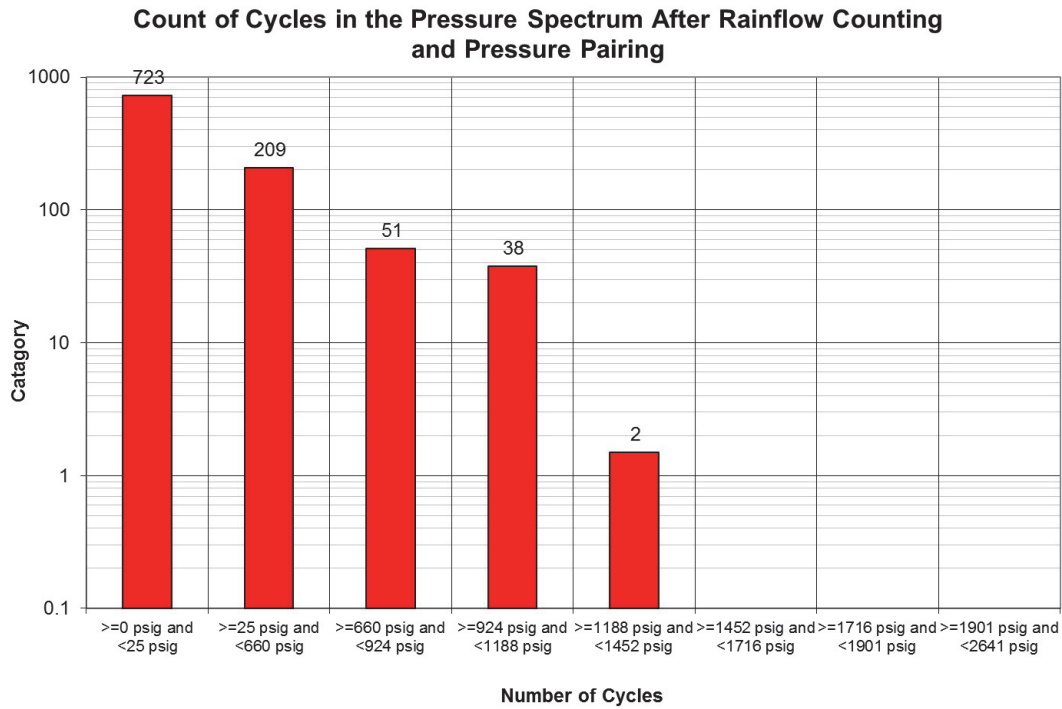


Figure 9—Example Histogram Resulting from Rainflow Cycle Counting

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):

$$\frac{da}{dN} = C(\Delta K)^n \quad (2)$$

where

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 n are constants that depend on the material and the environment;

ΔK is the change in stress intensity factor per cycle (psi-root-inch in U.S. customary units);

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

$$\Delta K = C_1 \Delta S \sqrt{\frac{\pi a}{Q}} \quad (3)$$

where

C_1 is a constant related to geometry;

ΔS 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 ΔK 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 n 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 n 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 n , 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):

$$\sum_k [n_k / N(\Delta\sigma_k)] = 1 \quad (4)$$

where

n_k is the number of occurrences of stress cycles of k^{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^{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 ΔK_{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 ΔK_{th} is 2.2 MPa (m)^{0.5} [2.0 ksi (in.)^{0.5}]. The applied ΔK as a function of applied stress cycle amplitude and incremental crack size can be calculated at each applied stress cycle and compared with ΔK_{th} to determine whether the crack would be expected to enlarge during that particular stress cycle. With a fixed ΔK_{th} , the applied stress cycle amplitude that exceeds the threshold decreases as the crack enlarges. For example, a threshold of 2.2 MPa (m)^{0.5} [2.0 ksi (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 5th percentile (L5), and upper 95th 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:

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

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 ΔK for those assumed defects can then be compared to a threshold ΔK 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.

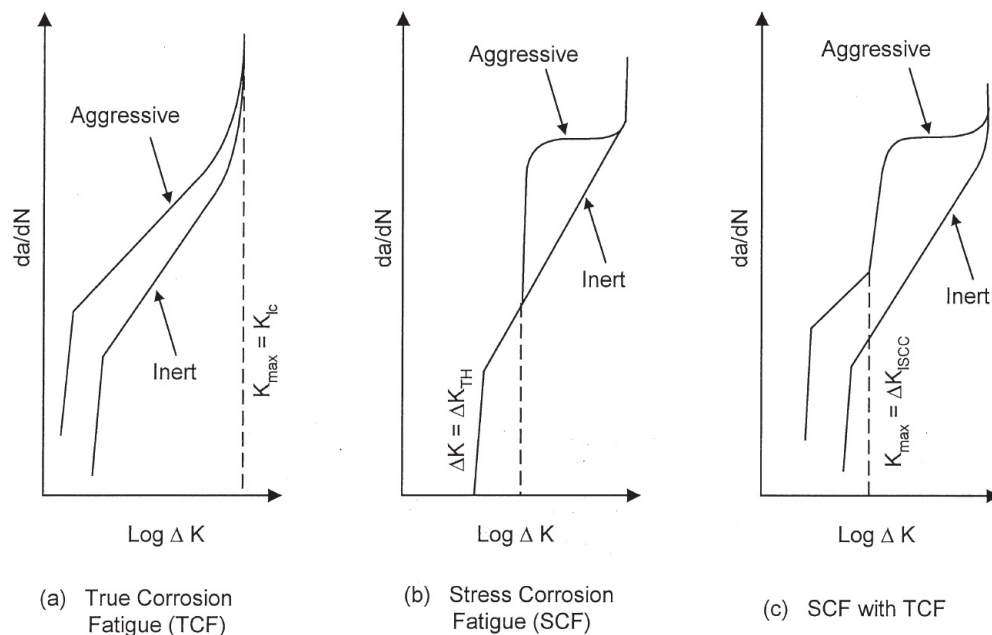


Figure 10—Coupling of Mechanical Fatigue with Environmental Crack Growth Mechanisms

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.